Application: 23-06-008
Exhibit No.: PGE-22
Date: April 15, 2025

PGE-22 EXHIBIT

PG&E RESPONSE TO DATA REQUESTJOINTEI_004-Q004 INCLUDING ATTACHMENTS

APRIL 15, 2025

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire and Gas Safety Costs
Application 23-06-008
Data Response

PG&E Data Request No.:	JointEI_004-Q004
PG&E File Name:	WildfireandGasSafetyCosts_DR_JointEI_004-Q004
Request Date:	March 13, 2025
Requester DR No.:	004
Requesting Party:	Energy Producers and Users Coalition (EPUC); Indicated Shippers
Requester:	Laura Chartrand
Date Sent:	March 26, 2025
PG&E Witness(es):	Lucy Redmond – Gas Engineering

QUESTION 004

Referring to PG&E testimony, page 2-Atch-7 through -14, “Regulation Timeline.”

a. Please provide a copy of the PG&E’s Underground Storage R&IMP and accompanying field specific Well Risk Evaluation and Construction Standard Implementation Plan (2019 Implementation Plan) provided to CalGEM. (Line 13).

b. Please provide a copy of the letter from CalGEM to PG&E re: Interim Testing Requirements. (Line 18).

c. Please provide a copy of PG&E’s response to CalGEM indicating concern regarding impact to near term and upcoming system reliability with the testing schedule required in Interim Testing Requirements. (Line 19).

d. Please provide a copy of the letter from CalGEM to PG&E directing PG&E to submit a revised implementation plan with an accelerated inspection schedule. (Line 20).

e. Please provide a copy of PG&E’s revised implementation plan to CalGEM(2021 Revised Implementation Plan). (Line 21).

f. Please provide a copy of CalGEM’s approval of PG&E’s 2021 Revised Implementation Plan. (Line 22).

g. Please provide a copy of CalGEM’s Response Letter. (Line 25).

ANSWER 004

a. For a copy of PG&E’s Underground Storage R&IMP and accompanying field specific Well Risk Evaluation and Construction Standard Implementation Plan (2019 Implementation Plan) provided to CalGEM, please see the following attachments:

- “*WildfireandGasSafetyCosts_DR_Joint-EI_004-Q004Atch01.pdf*” - PG&E’s Transmittal Letter – Sent 03/29/2019.

- *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch02.pdf*" - PG&E's Gas Storage Asset Management Risk & Integrity Management Plan 2019 Revision 5 – Dated 03/29/2019.
- *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch03.pdf*" - McDonald Island Underground Storage Field Implementation Plan. Dated 03/29/2019.
- *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch04.pdf"* - Los Medanos Underground Storage Field Implementation Plan. Dated 03/29/2019.
- "*WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch05.pdf*" - Pleasant Creek Underground Storage Field Implementation Plan. Dated 03/29/2019.

b. For a copy of the letter from CalGEM to PG&E re: Interim Testing Requirements with accompanying listing of wells, please see the following attachments:

- *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch06.pdf"* - Final CalGEM UGS Interim Testing Schedule Letter to PGE. Dated 09/30/2020.
- *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch07.xlsx" - Wells List PG&E 9.30.2020.*

c. Please see *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch08.pdf"* for a copy of PG&E's response to CalGEM indicating concern regarding impact to near term and upcoming system reliability with the testing schedule required in Interim Testing Requirements.

d. Please see *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch09.pdf"* for a copy of the letter from CalGEM to PG&E directing PG&E to submit a revised implementation plan with an accelerated inspection schedule.

e. Please see *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch10.pdf"* for a copy of PG&E's revised implementation plan to CalGEM (2021 Revised Implementation Plan).

f. Please see *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch11.pdf"* for a copy of CalGEM's approval of PG&E's 2021 Revised Implementation Plan.

g. Please see *"WildfireandGasSafetyCosts_DR_JointEI_004-Q004Atch12.pdf*" for a copy of CalGEM's Response Letter.

[redacted]
Pacific Gas and Electric Company
6121 Bollinger Canyon Road
San Ramon, CA 94583

March 29, 2019

By Email

Mr. Alan Walker
Division of Oil, Gas, and Geothermal Resources (DOGGR)
California Natural Resources Agency – Dept. of Conservation
801 K Street ▪ MS 18-05
Sacramento, CA 95814

RE: PG&E's Submission in accordance with DOGGR Final Regulations §1726

Dear Mr. Walker,

In accordance with the Title 14, Chapter 4, §1726, PG&E has submitted PG&E's Underground Storage Risk and Integrity Management Plan(WELL), Revision 5 to the Division of Oil, Gas, and Geothermal Resources (DOGGR). This is the foundation document for PG&E's approach to managing and mitigating the threats and hazards associated with the operation of underground natural gas storage facilities and applies equally to all three PG&E facilities: McDonald Island, Los Medanos, and Pleasant Creek.

Risk Evaluation & Tubing and Packer Retro-fit

Additionally, in accordance with §1726.3, PG&E has submitted the following companion documents to the WELL Plan for the well-by-well risk evaluation and construction implementation (§1726.3(d)).

- McDonald Island Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan
- Los Medanos Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan
- Pleasant Creek Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan.

These documents detail the process and application of the risk evaluation at the well level and lay out PG&E's current plan to complete baseline casing inspections and convert the existing well configuration to tubing and packer over a seven-year implementation period beginning this year in 2019.

Emergency Response

Within the WELL plan, PG&E describes the approach in place for emergency response. PG&E response protocol is structured using the Gas Operations Emergency Response

[redacted]
Pacific Gas and Electric Company
6121 Bollinger Canyon Road
San Ramon, CA 94583

Plan (GERP) in concert with PG&E's Well Control Tactical Considerations Plan (WCTC) and the site-specific relief well plans, as appropriate. A copy of PG&E's GERP and WCTC are being provided to the Division in accordance with §1726.3.1.

UGS Project Data

Additionally, PG&E has prepared and submitted reports detailing the data requirements outlined in §1726.4 and a wellbore database file for each facility: McDonald Island, Los Medanos, and Pleasant Creek.

Clarification Request

The documents noted above and submitted under the requirements are currently in place and PG&E continues to operate under the guidance, standards, and process within. PG&E understands it is the Division's intent to review each of these documents and it will take time to receive approval. PG&E respectfully seeks the Division's early concurrence and clarification on the following:

Construction Standard Implementation Timeline

PG&E understands the regulations were effective October 1, 2018 and 1726.3(d) required within the first year 10% of non-conforming wells to be converted to T&P. As such, PG&E is planning for 2019 well conversions to be completed by October 1, 2019.

PG&E seeks clarification if the Division's intent of 1726.3(d) views the conversion timeline to be that of October-to-October, or if the intent is to follow a traditional calendar year and completing the required percentage by December 31 of a given year.

Subsurface Safety Valve Testing §1726.8(a)

PG&E seeks clarification to the style of test the Division is intending to be notified for the opportunity to witness subsurface testing. Under the existing Risk and Integrity Management Plan, PG&E performs both function tests and the extended annual leak-by tests; note, a typical leak-by test is conducted over a four-hour period.

It is PG&E's understanding it is the Division's intent of §1726.8(a) to continue to be notified for opportunity to witness the function testing similar to the existing practice put forth in the Emergency Regulations in February 2016.

Additionally, PG&E seeks clarification that the Division is not required to witness the testing under the language in §1726.8(a) provided a notification was made 48 hours in advance and PG&E maintains the record of testing.

[redacted]
Pacific Gas and Electric Company
6121 Bollinger Canyon Road
San Ramon, CA 94583

The WELL Plan, Rev 5, Section 11 details PG&E's approach to safety valve operation, maintenance and inspection. The following frequencies and allowances are aligned with PG&E's Gas Operation standards for performing routine asset maintenance and testing associated with the transmission and distribution valves under CFR Part 192:

- Function Testing – Every 6 months, not to exceed 8 months
- Leak-by Testing – Annually, not to exceed 15 months.

Noise & Temperature Annual Survey 1726.6(a)(1)

PG&E performs annual noise and temperature surveys on all wells and this has been a practice in place since the 1990's. PG&E typically targets to complete these surveys during inventory verification periods, i.e. when the fields are shut-in and noise interference from normal operations is limited. Inventory verifications are typically within the same calendar month year over year, however, PG&E seeks the Division's concurrence that performing these surveys once per annum within the typical operation window meets the intent of the annual requirement and further it is not the intent of the Division to require these surveys be performed to the day each year.

Leak Notification §1726.9

PG&E's respective Storage field monitoring plans required under the O&G law were accepted by the California Air Resource Board(CARB). PG&E seeks clarification from the Division regarding requirement notification of leaks that can be repaired the same day as identified via tightening, lube, and adjusting (TLA) methods and is the practice accepted by CARB.

For any questions you may have regarding any of the submittal documents, please feel free to contact Lucy Redmond at [redacted] or myself at [redacted]

Thank You,

[redacted]
Director
Pacific Gas and Electric

Underground Storage Risk and Integrity Management Plan

Gas Storage Asset Management Department

Publication Date: March 29, 2019
Revision 5

Underground Storage Risk and Integrity Management Plan

This plan provides guidance in the form of standards and procedures for PG&E's underground gas storage field design, maintenance and operations. This plan is supplemented by companion documents referenced throughout and listed in Appendix AB.

TABLE OF CONTENTS

Underground Storage Risk and Integrity Management Plan

Underground Storage Risk and Integrity Management Plan

1. Introduction

Pacific Gas and Electric Company (PG&E) underground natural gas storage fields help provide customers with safe, reliable and affordable gas throughout the year and provide peak day gas supply during high-demand periods. The gas in the storage fields belongs to PG&E and customers and is injected, stored, and withdrawn as required.

This Underground Storage Risk and Integrity Management Plan (the "Plan" or "IMP") has been developed to provide guidance to personnel involved in all aspects of storage field operations to protect the public, environment, and company and contract personnel. This guidance is in compliance with the the Pipeline and Hazardous Materials Safety Administration (PHMSA) IFR - Interim Final Rule issued by PHMSA and incorporates by reference, American Petroleum Institute (API) Recommended Practice 1171. The Plan is designed to be PG&E's central guidance document to support maintenance of the functional integrity of storage wells and reservoirs as well as the prevention and mitigation (P&M) activities to manage the associated risk. These activities are founded on PG&E SME experience, and industry recommended practices and applicable to the specific work to be performed. Principles of process safety have also been incorporated into the practices as identified in the Plan.

Implementation of this plan allows PG&E to identify potential threats and hazards to reservoir and well integrity; assess risks based on potential severity and estimated likelihood of occurrence of each threat; identify the preventive and monitoring processes employed to mitigate the risk associated with each threat; and specify a process for periodic review and reevaluation of the risk assessment and prevention protocols. The plan is both a broadly-applicable level across assets groups and at site- and asset-specific level. Individual storage facility work plans outlining compliance of well assets to Section 1726.5 are provided in the following companion documents:

- McDonald Island Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan
- Los Medanos Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan
- Pleasant Creek Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan.

The products of the noted documents above are the well-by-well risk model and implementation plans for each field. The risk model and the implementation plan are living documents and are updated as needed based on continuous evaluation data received as part of the P&M measures outlined within this plan.

As part of integrity management, the Plan provides practices for assessing existing reservoir and well integrity, and for monitoring of existing reservoir and well operations to demonstrate and verify that the gas stored in the facility remains contained in the reservoir and protected from undesired reservoir gas migration or breaches in the wells.

The Plan does not address requirements for new storage field design and construction, expansion of existing storage capacity, commissioning of new or expanded capacity and drilling of new wells.

The Plan does not replace or restrict PG&E's compliance with any specific requirements applicable to pipelines and associated facilities pursuant to the United States Code of Federal Regulations Parts 190-199 of Title 49 and California Public Utilities Commission General Order No. 112.

2. Target Audience

Employees in departments involved with all aspects of gas storage operations such as Gas Storage Asset Management (GSAM), Gas Pipeline Operations & Maintenance (GPOM), Station Services, Corrosion Engineering, Pipeline Services, Transmission Integrity Management Program, and Leak Management.

This plan and the companion documents reside in the following locations, to ensure accessibility to the personnel listed above. Appendix AA and AB provide a detailed inventory and ownership of other documents, data and records beyond the boundaries of GSAM.

Document	Location
This plan	Storage Asset Family Shared Drive and Reservoir Engineering SharePoint
Guidance documents published by the Gas Operations Guidance Documents and Engineering Services Department (or the department successor)	Gas Operations Technical Information Library
Companion Guidance Documents developed or adopted by GSAM	GSAM shared drive

2.1. Training

Initial and refresher training are provided as needed to the identified target audience to ensure that personnel understand and adhere to the current published version of this Plan.

3. Regulatory Jurisdiction for Company Gas Storage Fields

Initial investments in and continued operation of the Company natural gas storage fields are subject to the jurisdiction of California Public Utility Commission (CPUC). The CPUC has issued Certificates of Public Convenience and Necessity for each PG&E storage facility.

Additionally, the safety, design, construction, operation, and maintenance are all performed under the jurisdiction of Federal Pipeline and Hazardous Materials Safety Administration (PHMSA), CPUC, and Department of Conservation rules and regulations.

4. Roles and Responsibilities

The stakeholders who are involved in the Plan are listed in the following table.

Table 1: Stakeholders

Department	Responsibilities Related to Storage Assets
Gas Storage Asset Family Owner	• Understand the condition of storage assets • Understand the risks to storage assets • Develop and implement asset risk reduction strategies • Develop long term financial plan • Ensure that training is in place for PG&E and third-party personnel who are involved in storage assets
Gas Pipeline Operations & Maintenance (GPOM)	• Operate the storage assets • Perform preventive and corrective maintenance on equipment, and ensure personnel receive training as appropriate. • Provide guidance and coordinate leak survey of storage facilities
Leak Survey Dept	• Conduct leak surveys. • Provide training to leak survey personnel.
Reservoir Engineering	• Maintain integrity of wells and reservoirs within storage facilities • Develop, deliver and receive training on prevention and mitigation measures to manage reservoir and equipment risks
Station Services/Facility Integrity Management	• Maintain integrity of pipe and surface equipment within Storage facilities
Corrosion Engineering	• Develop corrosion site specific plans for storage facilities • Ensure corrosion personnel receive training as appropriate.
Pipeline Services	• Maintain integrity for transmission pipe system including pipe near storage facilities • Ensure personnel receive training as appropriate.
Gas System Operations & Planning	• Manage inventory, deliverability capacity, and outage planning
Gas Emergency Preparedness	• Maintain the emergency response documentation and manage drills and exercises accordingly
Transmission Integrity Management Program	• Identify threats, assess asset condition, and prioritize mitigation work for transmission pipe system including pipe near Storage facilities • Ensure personnel receive training as appropriate.

5. Flow of Plan Activities and Frequency of Plan Updates

PG&E uses the guidance provided by American Petroleum Institute (API) Recommended Practice 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs for the design, operation, and maintenance of storage facilities.

The Plan will be reviewed on a frequency not to exceed 3 years for the entire document.

Guidance document review and modifications may be performed to account for circumstances such as changes in operating conditions (e.g., well and reservoir integrity performance, the number and types of issues that are occurring), as well as other issues, hazards or threats, advancements in technology, regulatory changes, abnormal operating conditions or as experience dictates. Reviews may also be conducted based on internal audits of the work being done by storage personnel (ref Section 24) to determine the adequacy and effectiveness of the procedures used in operation and maintenance of storage facilities.

Reviews of and changes to this plan and companion guidance documents published by GSAM shall be accomplished in a controlled manner in accordance with Section 22 (Change Control) of this plan.

6. UGS Integrity Management Process

The following activities are performed to demonstrate and verify reservoir and well integrity:

- Reservoir Characterization
- Reservoir Design Basis
- Field Integrity/Inventory Verification
- Observation Well Monitoring
- Monitor Third Party Wells
- LUAF (Lost & Unaccounted For)
- Measurement Correlation
- Inventory Verification Study
- Audit of Inventory report by Consultant
- Well Integrity
- Downhole Logging
- Annular Pressure Monitoring
- Gas Sampling
- Safety Valve Maintenance/Testing
- Wellhead Maintenance
- Remedial Action and Well Construction
- Well Pressure and Flow Monitoring
- Wellhead Inspections and Leak Survey
- Plugged well site inspections for evidence of gas or other fluid flows to surface.

7. Data Management

Traceable, verifiable, and complete gas storage asset data is maintained in an accessible manner to support asset operations and maintenance, and for regulatory inspection.

Refer to Section 24 and Appendix AA of this document for additional information on PG&E's record management program.

8. Reservoir Integrity

Ongoing verification and demonstration of the integrity of the reservoir includes demonstration that reservoir integrity will not be adversely impacted by operating conditions. Reservoir integrity is verified by inventory-bottomhole pressure surveys/shut-in test or other pressure decline analysis methods, monitoring observation wells, monitoring third-party existing and new wells, performing measurement correlation/audits, and lost and unaccounted-for gas studies.

Refer to Appendix P of this document.

8.1. Reservoir Characterization

Geological and engineering characteristics of the reservoir influence its performance and integrity capability. As new information that could influence integrity is available, the reservoir characterization is reviewed and updated.

The reservoir characterization addresses rock characteristics such as lithology and lithologic variation, porosity, permeability, average thickness, areal extent, caprock thickness, caprock threshold pressure, reservoir/caprock fracture gradient, locations and characteristics of faults and fractures, location and characteristics of any offset hydrocarbon operations, reservoir temperature, original and conversion pressure, original and produced native oil, gas and water, original and current fluid properties such as density, viscosity and chemistry.

The characterization is illustrated in the form of structure maps, isopachous maps, and a geologic cross section drawn through at least one well location with a type log incorporating the deepest producing zone. Illustrations are clearly labeled as to scale and purpose, with clearly identified wells, boundaries, zones, contacts and other relevant data. Updated characterizations are made available to appropriate regulatory agencies.

This information is maintained in current reports on GSAM Shared Drive.

8.2. Reservoir Design Basis

The reservoir design basis states the purpose of the storage service and incorporates operating limits that are updated to keep current. The design basis addresses the injection and withdrawal plans and methods, well type and distribution, maximum design reservoir and well flow rates, minimum design operating pressure and evidence for not exceeding geo-mechanical strength, maximum design operating pressure and evidence for not exceeding geo-mechanical or surface facility strength, observation well purposes and locations, cathodic protection systems, water source wells if any, water disposal operation, and surface and subsurface safety systems employed. The design basis is illustrated in maps showing all well locations and key pipeline facilities, cathodic protection facilities if any, water source and disposal wells if any. An updated design basis is made available to appropriate regulatory agencies, particularly as it accompanies intended changes or well additions requiring prior regulatory approval.

8.3. Inventory BHP Surveys/Shut-in Test or Other Pressure Decline Analysis Methods

Storage field inventory studies performed by GSAM verify the volume of gas in the storage reservoirs compared to the company booked volumes. Gas volumes that need reconciliation consist of native base gas, injected base gas, injected and withdrawn working gas (less fuel) and other losses, both measured and estimated. These studies consist of conducting a pressure-inventory analysis for each storage reservoir. A detailed description of the methodology, terms, and definitions related to inventory studies is included in Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification.

8.4. Observation (OBS) Well Monitoring

Observation (OBS) wells are utilized to monitor gas pressure movement within a storage zone and to monitor the potential for gas migration away from the storage zone or movement to other porous zones above or below the storage zone. Some OBS wells were originally oil/gas production wells obtained with the acquisition of the field and others were drilled as part of the development of the field.

Observation well pressure data is utilized to monitor the reservoir pressure versus inventory relationship and trends indicating field stabilization or anomalies which may be indicative of gas loss or migration.

Gas samples are obtained and analyzed from OBS wells and selected injection/withdrawal wells to determine if changes in gas composition occur over time and is conducted per Appendix O, Practice 11 – Observation and Selected I/W Well Gas Sampling. The samples may be taken from OBS wells completed in the fringe area of the storage zone and/or OBS wells completed in porous zones above or below the storage zone. This information is recorded in the Gas Storage Database (GSDB).

Changes in gas composition may indicate movement of storage gas toward storage boundaries, or may indicate a need to reassess the inventory (see Appendix P) since gas composition can affect inventory calculation. This information is valuable for identification of potential storage gas migration.

Some injection/withdrawal (I/W) wells that are connected to the transmission pipe of the corresponding storage fields are not utilized to flow gas into or out of the reservoirs but are utilized for reservoir monitoring purposes similar to OBS wells. The following lists questions PG&E may consider when evaluating pressure response and gas sample data from an OBS well or an I/W well:

- Are pressure changes observed at the surface or bottom hole?

- What is the fluid observed in the well – oil, gas, brine, etc.? If gas, does the gas sample reflect native or storage gas?
- Which formation is the OBS well monitoring – the storage zone, fringe area of the storage zone or potential porous zones above or below the storage zone into which gas could migrate?
- Status of nearby wells – what does the data from offsetting wells provide?
- Well mechanical integrity history
- Does annular pressure monitoring data indicate the integrity of tubing or casing?
- Are apparent defects present on casing inspection logs? If so, what is the rate of change of apparent defects?
- Well location – is the well near houses, buildings, roads or waterways?
- Does the pressure of this well track closely with the reservoir pressure?
- Is this well being used for gas injection and/or gas withdrawal?
- Is the drainage area from this well a low percentage?
- Is the gas analysis from this well similar to the gas analysis from the remainder of the reservoir?

8.5. Monitor Third-Party Existing and New Wells

An important part of maintaining storage field integrity is evaluating the mechanical integrity and verifying that any third-party wells within the protection acreage and/or penetrating the storage reservoir are adequately designed to prevent the leakage of gas from the reservoir. PG&E also attempts to periodically monitor third party wells to detect leaks that may develop later in the life of a well.

PG&E seeks to obtain written access agreements with the operators of existing and new third-party active wells to minimize operational misunderstandings and future problems. This includes requesting well integrity evaluation data from third party well owner/operators following the frequency established using conclusions from the risk assessment and seeks assurances that all planned third-party wells that will penetrate its storage reservoirs comply with state regulations; PG&E does not waive any state regulation nor accept attempts to lessen any. If allowed by the operator, PG&E monitors the drilling, cementing and logging of any third-party well.

Results of PG&E's attempts to understand risks associated with third-party wells are documented in folders for the applicable storage field asset on GSAM's shared drive.

The following criteria is considered in the evaluation of existing and new third-party wells that are within the protection acreage and/or penetrate the storage reservoir.

8.5.1.1. Existing Wells

- Thoroughly review the state regulations for third-party wells penetrating PG&E's gas storage reservoirs and specific state regulations pertaining to individual reservoirs and verify that these rules are strictly followed.

- Identify well location, serial, and state permit or API number, production interval, total depth, and operator for all wells within PG&E storage field boundaries.
- Obtain available well data, schematics, and logs, and conduct a thorough review of state files.
- Obtain gas, oil, and water production data from the state and/or well data from service companies.
- Monitor production data annually and look for anomalies.
- Sample the storage reservoir gas and, if necessary, obtain a gas analysis from the existing well to be used for comparison purposes.
- Open dialogue with outside operator and obtain written permission to perform the following, if practicable:
- Routinely monitor all annular and tubing pressures.
- Sample the gas streams including the tubing and the tubing-casing annuli (TCA) and perform a gas analysis at least once but more often if anomalies are identified. Resample if the producing horizon changes.
- Seek information on plugged and abandoned wells within the protection acreage.
- For wells located within the lateral and vertical buffer zone being plugged and abandoned by a third party, confirm that the storage reservoir will remain isolated to protect its integrity.
- GSAM shall conduct an initial review of plugging records, and again only for cause, such as changes in condition found by leak survey or other observations.

8.5.1.2. New Wells

- Review the design and completion of the well. Verify that the storage zone will be properly isolated by cement and that the casing design is adequate for storage field pressures.
- To the extent practicable, monitor the drilling, cementing, logging, and perforating operations of third-party wells.
- Review all available logs and identify any anomalies.
- If PG&E suspects that the integrity of its storage reservoir has been breached by a new well, PG&E will contact the operator and attempt to negotiate a plan for remedial action.

8.6. Measurement Correlation and Lost and Unaccounted For (LUAF) Studies

Metering errors and fuel/station gas usage for underground gas storage operations represent gas “losses” from inventory and are accounted for monthly. The following potential gas losses are considered to verify gas inventory.

- Engine starting gas utilized (number of starts times the volume of a typical start).
- Venting volume of compressor and piping each time a unit is shut down and the number of times it is shut down each month.
- Emergency shut down (ESD) blow down volumes.
- Other equipment depressurizing (volume of each event).
- Station fuel.
- Well blow downs (number of wells, starting pressure, and volume of each).
- Transmission pipe system header blow downs.
- Relief valve discharge occurrences and estimate of volume.
- Flash gas from atmospheric tanks.
- Flare gas, where applicable.
- Diffuse gas losses from leaking valves, flanges, and screwed pipe.

9. Mechanical Integrity of Wells

Ongoing verification and demonstration of the mechanical integrity of each well used in the underground gas storage project and each well that intersects the reservoir used for gas storage are performed. The protocols for verifying and demonstrating well integrity shall not be limited to compliance with the mechanical integrity testing requirements under Section 1724.10(j) and include consideration of risk-based decisions for each well.

Gas storage wells may be in service for 75 or more years. Therefore, it is prudent to design the wells to remain intact for that time period and to monitor and maintain the integrity to prevent gas leakage. Methods utilized to assess and prevent future casing failures and gas releases include storage well logging, cathodic protection and monitoring, MIT (Mechanical Integrity Test), and annular pressure monitoring. Refer to Appendix Z which illustrates the process flow for the testing regime to demonstrate well integrity.

9.1. Well Characterization and Analysis

Each active and plugged well within the buffer zone is characterized for its mechanical "as is" condition by means of a wellbore schematic (and wellhead diagram for active wells) utilizing the practices in Appendices F and G. The schematics and diagrams are maintained in a current state and reflect the most recent well entry findings, workovers, integrity tests, and equipment changes.

Each active and plugged well within the buffer zone is evaluated for its current mechanical integrity utilizing a barrier analysis methodology to identify any deficiencies that need to be addressed. The barrier analysis incorporates tubular and wellhead design safety factors and cementing standards that meet or exceed minimum regulatory requirement.

Subsequent evaluations are conducted as determined using the risk assessment and the information derived from the initial evaluation. Process and results are documented as described in each section below. Records are maintained by asset in the GSAM shared drive.

9.2. Storage Well Logging

9.2.1. Well Logging

Wells are logged to identify potential problems and may include the following types of cased hole logs (type of log/survey identified in parenthesis).

- Reductions to casing wall thickness (MFL, Caliper, and Ultrasonic Casing Inspection Tools)
- Identification of gas presence behind the casing (Gamma Ray-Neutron – GRN, Pulse Neutron)
- Cement Bond Log (CBL)
- Presence of a corrosion cell (Casing Potential Profile – CPP)
- Temperature logs
- Noise logs
- Downhole video cameras
- E-Log-I surveys

9.2.2. Future Well Logs

In addition, for future new storage wells, the following list of logs shall be considered to be run during drilling and completion. The principle (how the log works) and the identification (purpose of the log) are presented in Appendix A, Well Logging Criteria for New Wells, along with the list of logs.

9.2.2.1. Open Hole Logs

- Caliper
- Density w/Pe (Litho-Density)
- Compensated Neutron Log (CNL)
- Spontaneous Potential (SP)
- Gamma Ray (GR)
- Resistivity Logs (Dual-Induction or Array Induction)
- Microlog (ML)

9.2.2.2. Cased Hole Logs

- Casing Inspection Tools (i.e., Vertilog, MicroVertilog, High-Resolution Vertilog, Caliper, and Ultrasonic inspections)

- Cement Bond Log/Cement Mapping Tool with Gamma Ray and Casing Collar Locator or Segmented Bond Tool with Gamma Ray and Casing Collar Locator

- Base line TDT/PDK with Gamma Ray and Casing Collar Locator or Gamma Ray Neutron with Casing Collar Locator

9.3. Casing Inspection Tools

Casing inspection tools are beneficial to establish baseline casing and tubing. The following criteria summary should be utilized (See Appendix C, Casing Inspection Survey Frequency Decision Tree for further details):

- Run baseline logs (casing inspections and/or GRN) on every well when the tubulars are removed (typically during a rework).
- Follow-up casing inspections are required on casing completed wells to assess the rate of change in pipe corrosion at time intervals to be determined by the condition of the pipe.
- Follow-up casing inspections on tubing and packer completed wells are required when tubing is pulled for other remedial work and with consideration of the time interval between the remedial work and the last casing inspection run.
- Noise and Temperature logs (annually) and GRN logs (periodic) will be run on tubing and packer completed wells that do not have baseline casing inspections to identify changes in gas accumulation behind pipe and review.
- Thru-tubing inspection logs are a new practice for PG&E and when used in conjunction with traditional casing inspection logging tools provides an opportunity to monitor for accelerated wall loss feature growth during surveillance inspections. Additionally, run ahead of baseline condition, these logs present an opportunity to flag large metal feature defects.

For more details, please refer to Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments.

9.4. Casing Potential Profile (CPP)

Coordination and communication with the Operations department to verify that wells are protected by a cathodic protection system. Periodically, E-Log-I surveys may be conducted by Corrosion department to verify that adequate cathodic protection current is being applied to each well’s production casing string.

10. Casing Pressure Tests and Annulus Monitoring

This section addresses testing and monitoring, and is supported in detail in Appendix K, Practice 7 – Mechanical Integrity Test Acceptance and Frequency, Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring, Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring, and Appendix Z, Well Integrity Testing Regime Process – Production Casing.

Records are maintained on GSAM’s shared drive in folders specific to each well.

10.1. Mechanical Integrity Test (MIT)

Wellbore mechanical integrity tests (MIT) are hydrostatic tests that demonstrate that the well casing, tubing, casing-tubing annulus and packer is capable of holding a pressure at the time the test was conducted. Performing MIT on wells completed with tubing and packer is relatively simple due to the nature of the completion. A pump truck is connected to the casing valve and fluid is slowly pumped until the annular pressure reaches the desired pressure. The tubing is pressure tested by setting a plug in the bottom of the tubing string and pumping fluid into the tubing until the pressure reaches the desired pressure.

The pressures test shall be conducted for one hour at 115% of maximum operating pressure (MOP) or the minimum yield strength of the casing and tubing, whichever is less. A passing pressure test meets the following criteria:

- the pressure loss in the first 30-minutes does not exceed 10% of the initial test pressure, and
- the pressure loss in the second 30-minute interval does not exceed 2% of the pressure in the first 30-minute interval.

A casing MIT test is to be performed on a well upon completion and for a well completed with tubing and packer, at a rate of not less than one test every five years. If, during the five year test interval the tubing and packer is removed and replaced, a MIT will be conducted prior to returning the well to service.

Refer to Appendix K and Appendix Z for additional details.

10.2. Annulus Monitoring

Monitoring of the well annuli for the presence of gas and pressure is completed daily and more frequent if determined necessary. To minimize corrosion in the casing for wells where the casing is not cemented to surface, the annulus should be liquid filled and shut-in to prevent atmospheric corrosion. Any anomalous annulus pressures must be reported immediately to the manager, supervisor, and engineer. A plan of action should be developed to assess the anomalous pressure and could include taking the well out of service, collecting gas sample(s), and conducting a blow down test.

Refer to Appendix L, Practice 8 – Annular Pressure and Gas Sampling Monitoring and Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring for additional information.

10.3. Tubing Casing Annulus (TCA) Monitoring for Wells Completed with Tubing Set on Packer

Monitoring of tubing casing annulus (TCA) for the presence of gas and pressure is completed daily. If a well exceeds its historically observed pressures by 100 psi, it will be documented in the well annular monitoring plan and reviewed by an engineer to determine if a blow down test is required. If it is a new event within the documented history of the well, a blow down test shall be conducted in accordance with Appendix L.

Note, it is common to observe elevated pressures following an MIT that uses water immediately following the MIT due to expansion caused by high bottom hole temperatures. This is an example where pressures exceeding 100psi would not require a blow down test.

Initial pressure, final pressure, and blow down time should be recorded on all blow down testing and submitted to engineering. Based on blow down test results, any required remedial action including gas analysis and work overs will be determined and a decision to keep the well in service will be made by the manager, supervisor, and engineer. If a well decreases in pressure by 100 psi or goes on vacuum, it will be reported on the monthly field reports and evaluated for the cause, i.e. packer fluid leaking from the annulus versus cooling effects.

11. Safety Valve Operation, Maintenance and Inspection

PG&E’s storage fields are equipped with safety valve systems to isolate the various assets as part of the emergency shutdown systems. Storage wells and the connecting piping should be risk assessed on the need to provide isolation during an event[1]. The cause of these events could arise as from the integrity failure of a well or pipeline, runaway trucks, explosions, outside natural forces, vandalism/terrorism, or other nearby construction activities.

Wells equipped with a “downhole” safety valve (DHSV) or surface controlled subsurface safety valves (SCSSV) typically have valves installed 250 feet below ground level to provide emergency shutdown in the event the storage well cannot be isolated by the wellhead master valve. DHSV valves are surface controlled, hydraulically operated and are “fail safe” type valves (hydraulic control system pressure keeps the valves open, and the valves close on loss of hydraulic control system pressure).

“Uphole” safety valves (UHSV) or emergency shutdown valves (ESD) are installed on the transmission piping to isolate the transmission pipeline from abnormal low pressure downstream of the valve, including loss of containment of a storage well or the piping systems. UHSV are typically installed near the connection of the transmission piping and storage wellhead.

Safety valve systems are maintained in accordance with Utility Standard: TD-4521S Gas Valve Maintenance Standard and by personnel who have received training in preventative and mitigated activities (typically referred to as maintenance) under PG&E's operator qualification (OQ) program. Contract personnel (such as downhole safety valve manufacturer) engaged to perform preventative and corrective maintenance on this equipment accordingly are trained by the manufacturer or must demonstrate training.

Refer to Appendix AH for further information.

---

[1] CFR 192.12 – incorporated API RP 1171, Section 6.2.5 Emergency Shutdown Valves, Section 9.3.2 function testing practice for surface and surface safety valve systems. CCR, Title 14, Chapter 4, Subpart 1, Article 3; 1726.8 - Inspection, Testing, and Maintenance of Wellheads and Valves, Section (a) and 1726.3(d)(1) – Risk Management Plan. API RP 14B – Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems referenced by PHMSA and DOGGR.

11.1. Testing / Inspection

Function tests shall be performed on safety valve system at least every six months, not to exceed 8 months, and leak-by tests shall be performed at least once annually, not to exceed 15 months, in accordance with IMP Appendix I, Practice 5: Uphole Safety Valve (UHSV) Leak Test Procedures and Appendix R, Practice 14: Downhole Safety Valve (DHSV) Leak Testing.

11.1.1 Testing Notification

GPOM shall notify the DOGGR at least 48 hours before performing function testing so they may witness the operations. Documentation of the testing shall be maintained and available for DOGGR review.

11.2. Operations

IFR requirement 9.3.3, "a closed storage well safety valve system shall be manually re-opened at the site of the valve after an inspection and not opened from a remote location" is interpreted by PG&E as the following:

- To apply to situations where the safety valve trips and must be reset, and not to routine testing of safety valves addressed in the Testing / Inspection section above.
- To allow re-opening of the valve from the valve site or the control room or any intermediate location, provided that the reason for the trip has been investigated and the safety of re-opening has been confirmed.

Specific requirements for operation of safety valves in the event of a trip or abnormal operating condition reside in the operating procedures developed and maintained by GPOM for each storage field.

11.3. Records

Safety valve testing, maintenance and repair records are created by GPOM, and are maintained on the GPOM hardcopy records systems.

Records involving repairs conducted by third party service providers that are developed as part of project work are maintained in GSAM's shared drive in a folder associated with that asset and that project. However, maintenance records that change as a result of the project are updated and maintained by GPOM.

12. Wellhead (Christmas Tree) Valve Operation, Maintenance and Inspection

Storage wellhead (Christmas Tree) valves must be maintained in order to ensure that they can be operated as intended to shut off gas flow or isolate a well in the event of an emergency or for routine maintenance.

Valves are maintained in accordance with Utility Standard: TD-4521S Gas Valve Maintenance Standard and by personnel who have received training in preventative and mitigated activities (typically referred to as maintenance) under PG&E's operator qualification (OQ) program.

Contract or other personnel (such as valve manufacturer) engaged to perform preventative and corrective maintenance on this equipment accordingly are trained by the manufacturer or must demonstrate training.

Refer to Appendix AH for additional information.

Valve operation, maintenance and inspection in addition are governed by

- This section
- Valve manufacturer maintenance instructions
- Natural Gas Underground Storage Facility Monitoring Plan – Facility: McDonald Island (CARB approved plan and listed in Appendix AB)
- Natural Gas Underground Storage Facility Monitoring Plan – Facility: Los Medanos (CARB approved plan and listed in Appendix AB)
- Natural Gas Underground Storage Facility Monitoring Plan – Facility: Pleasant Creek (CARB approved plan and listed in Appendix AB)
- Guidance documents and forms listed in Table 2 – Wellhead Valve Guidance Documents.

Table 2 – Wellhead Valve Guidance Documents

File Name	Title / Notes
McDonald Island Christmas Tree Valve Testing Non-Platform 4-13-2016.doc	McDonald Island valve testing procedure
MI LM PC CHRISTMAS TREE VALVE TEST FORM.xlsx	McDonald Island data logging form
Los Medanos Christmas Tree Valve Testing Program 4-11-2016.doc	Los Medanos valve testing procedure
Los Medanos CHRISTMAS TREE TEST FORM_03232016.xlsx	Los Medanos data logging form
Pleasant Creek Christmas Tree Valve Testing Program 4-11-2016.doc	Pleasant Creek valve testing procedure
Pleasant Creek Christmas Tree Valve Test Form	Pleasant Creek data logging form

12.1. Testing

Function tests shall be performed at least once each calendar year not to exceed 12 months and monitoring of wellhead pressures are conducted according to Appendix J, Practice 6 – Wellhead Pressure Monitoring.

12.3. Inspection – Routine and Preventative Maintenance

Inspection: Routine and preventative maintenance tasks should be conducted in accordance to Utility Standard: TD-4521S Gas Valve Maintenance Standard.

12.4. Records

Valve testing, maintenance and repair records are created by GPOM, and are maintained on the GPOM hardcopy records systems and/or SAP, as applicable.

Monitoring pressures are maintained by GSAM.

13. Corrosion Monitoring and Evaluation

Corrosion monitoring and evaluation (including risk assessment) is performed at storage facilities to evaluate the potential for corrosion and the effectiveness of mitigative measures. Corrosion monitoring data is also utilized to establish integrity assessment priorities and the results of integrity assessments are used to further evaluate the effectiveness of the corrosion control program at storage facilities. Elements of the corrosion monitoring and evaluate program are discussed below.

Corrosion monitoring and evaluation should address the following:

- corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures;
- annular and packer fluid corrosion potential; and
- corrosion potential of current flows associated with cathodic protection systems.

13.1. Tubular Integrity

Evaluation of tubular integrity and identification of defects caused by corrosion, erosion or other chemical or mechanical damage is performed by using a casing inspection tool and visual inspection during well reworks. For more details on casing inspections, refer to Section 9.3: Casing Inspection Tools.

During well reworks a visual inspection is performed on tubing for apparent external corrosion including:

- Corrosion in the threads of the tool joints
- Apparent pits and holidays
- Excessive rust and scales

The frequency of wall thickness monitoring should be evaluated using risk assessment and in alignment with Appendix C, Casing Inspection Survey Frequency Decision Tree.

13.2. Wellbore Produced Fluids and Solids

Gas, liquid, and solids samples will be collected from active flow lines during withdrawal season to evaluate the corrosive potential of the product stream. Liquid sample collection points are currently limited to comingled product streams; however, piping modifications are being evaluated to facilitate liquid sampling from individual flow lines. Corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures is discussed below.

13.2.1. Operating Pressure

Minimum withdrawal flow rates are established to lift fluid from the bottom of the well to the surface. Fluid production is anticipated for wells as during withdrawal operation to meet demand.

As the corrosive potential of produced liquids is related to operating pressures, pressures will be recorded during each gas sampling event to further evaluate the corrosion potential of produced gas and liquids.

13.2.2. Gas Sampling

Corrosion evaluations may be performed using gas sampling results for water vapor, carbon dioxide, and hydrogen sulfide content. Carbon dioxide and hydrogen sulfide concentrations are converted to partial pressures to further evaluate the corrosion potential based on reservoir pressure.

Gas samples are collected at each observation wellhead monthly to establish a baseline for a gas withdrawal season. PG&E has historically spot sampled gas quality at wellheads and historic data indicates minimal changes in gas quality during the withdrawal season. Results of the baseline sampling are evaluated to determine whether changes in the sampling frequency can be supported and if warranted are recommended in the annual inventory reports.

Additionally, gas sampling may be performed at I/W wells in response to an annular condition per Appendix L.

13.2.3. Produced Liquid / Sludge Sampling

Liquid sample collection points are currently limited to comingled product streams; however, piping modifications are being evaluated to facilitate future liquid sampling from individual flow lines. At the time of this Plan's publication, produced fluids are collected and analyzed per PG&E's Sampling Plan - Produced Fluid Collection for Disposal at Class II Injection Wells from a comingled source.

PG&E has historically sampled liquids at traps / drains / separators installed downstream of individual flow lines. Once piping modifications to the facility are made, the results of the baseline sampling will be evaluated to compare the corrosive potential of produced liquids from individual wells and flow lines to historic data obtained from the comingled product stream. This analysis will determine whether changes in the sampling frequency and / or locations can be supported.

Additionally, in alignment with each specific storage field Well Risk Evaluation and Construction Standard Implementation Plans, PG&E is in the process of installing individual well sampling drip pots and coupons to allow for individual well fluid sampling that will be installed from 2019-2025.

13.2.4. Sand Inspections

When gas wells produce gas at high velocities in the tubing or casing, any sand that is picked up in the flow stream becomes a potentially destructive element. Sand that is blasted against the piping, valves, chokes, or other parts of the system can destroy equipment in a very short time. Further, the presence of sand is an indicator of a potential failure of the well's gravel pack and screen liner to prevent sand production. The sand inspections occur twice during the winter withdrawal period under a standard clearance: typically, once in January and once in March. If sand is detected, Reservoir Engineering will evaluate whether to reduce rate, shut-in a well, schedule to re-gravel pack and install a new screen liner, or another appropriate mitigation.

Refer to the Appendix H, Practice 4 - Sand Inspection for further details.

13.3. Annular Packer Fluid

To minimize the corrosion potential of the annular between the casing and the tubing, packer fluid with corrosion inhibitor is placed in annular and packer behind the scab liner / inner string. Annular filled with packer fluid can minimize the annular exposure to atmospheric corrosion (oxidation).

13.4. Current Flows Associated with Cathodic Protection Systems

Cathodic Protection (CP) is an electrochemical process that when applied adequately can greatly reduce corrosion rates of metallic structures. The external surface of well casings and production strings that are in contact with the soil at gas storage facilities are provided external corrosion protection by an impressed current cathodic protection system. Impressed current rectifiers are monitored bimonthly and structure to electrolyte potential testing is conducted annually to determine the effectiveness and adequacy of the CP system. Results are integrated with downhole metal loss and casing potential logs to further evaluate the performance of the corrosion control systems.

13.5. Formation Fluids

Corrosion potential of all formation fluids is further reduced when cement is placed between the formation and production casing to isolate fluid from contacting the casing from the above storage zone. For more details, please refer to Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment.

13.6. Uncemented Casing Annuli

Methods to monitor corrosion potential of the uncemented casing annuli include running MFL, Ultrasonic, and Caliper logs to determine metal loss and a decrease in casing thickness due to corrosion or erosion.

13.7. Pipeline and Other Production Facilities

13.7.1. Pipeline Assessments

PG&E applies the Transmission Integrity Management Program (TIMP) to all transmission pipe, including pipe operating within storage fields meeting the requirements of 49 CFR part 192 Subpart O. This includes High Consequence Area (HCA) analysis, threat identification and risk assessment on all transmission pipe on an annual basis. For HCAs, assessments and reassessments of the identified threats are performed within the code-prescribed timeframes and may include External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA), Stress Corrosion Cracking Direct Assessment (SCCDA), In-Line Inspection (ILI), and Hydrostatic Testing. In addition, PG&E is currently considering a threat assessment program to assess non-HCA pipe in exceedance of minimum code requirements.

13.7.2. Atmospheric Coating Systems

Above grade piping, to include wellheads and gas measurement / treatment equipment, is protected with atmospheric coating systems that are inspected on three-year intervals.

13.7.3. Cathodic Protection

Buried and/or submerged piping is protected by underground coating systems and impressed current cathodic protection systems that are monitored at intervals described in Section 13.4. Cathodic Protection (CP) is an electrochemical process that when applied adequately can greatly reduce corrosion rates of metallic structures. The external surface of well casings and production strings that are in contact with the soil at gas storage facilities are provided external corrosion protection by an impressed current cathodic protection system. Impressed current rectifiers are monitored bimonthly and structure to electrolyte potential testing is conducted annually to determine the effectiveness and adequacy of the CP system.

13.7.5. Internal Corrosion Site Specific Plans

Internal corrosion (IC) monitoring, flow modeling, and nondestructive examination (NDE) are utilized to monitor the threat of IC. Identified sections of high risk pipeline areas are targeted for additional inspection by using radiography and/or ultrasonic thickness (UT) testing to further evaluate the potential for internal corrosion. Additional monitoring may include weight loss coupons, UT monitoring probes, and/or electrical resistance (ER) probes will be utilized as required. Other metallic facilities that store or transport gas (such as filter separators) are inspected for internal corrosion on a risk-based schedule maintained by Facilities.

Liquid samples are analyzed, as available, for corrosive constituents including, but not limited to: pH, chlorides, and bacteria (types that initiate microbiologically induced corrosion).

PG&E conducts sand inspections to monitor for sand that may cause erosion corrosion damage in the pipelines and downstream equipment as described in Section 13.2.4.

14. Evaluation of Wells and Attendant Production Facilities

Protocols for evaluation of wells and attendant production facilities include monitoring of casing pressure changes at the wellhead, analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures, and analysis of the specific impacts that the intended operating pressure range could have on the corrosive potential of fluids in the system. Evaluation and management of attendant production facilities follow requirements in 49 CFR 192. These are addressed in the following sub-sections:

14.1. Casing Pressure and Flow Changes at the Wellhead

Casing pressure and deliverability flow changes at the wellhead are monitored and evaluated. For more details, please refer to Appendix L, Practice 8 – Annular Pressure and Gas Sampling Monitoring, Appendix N, Practice 10 – Wellhead Annuli Pressure Monitoring, and Appendix M, Practice 9 - Individual Well Performance Monitoring.

14.2. Facility Flow Erosion

Flow erosion mitigation is incorporated into facility design, past and present. Examples include targeted tees and long radius bends/sweeps.

Flow erosion is monitored through sand inspections (ref Appendix H), wall thickness inspections (Section 9.2.1, Section 11.1 and Section 13.1, and Appendix C).

The frequency of downhole wall thickness monitoring is evaluated using risk assessment Appendix C for casing inspections.

14.3. Hydrate Potential

Hydrates can form due to a combination of temperature, gas composition, and pressure. Hydrates pose a risk to the system and can plug or rupture lines and can cause extensive equipment damage. In general, hydrate formation can be prevented using dehydration systems, heaters, insulated/heat traced lines, and methanol injection. All three of PG&E storage facilities use gas dehydrators as a way to minimize free water in the gas flow. In addition, Los Medanos has heaters located at well meters. Also, at McDonald Island a majority of aboveground well lines are insulated and heat traced, and the facility uses a methanol injection system to inhibit and suppress hydrate formation.

14.4. Facility Component Capacity and Fluid Disposal Capability

Facility components are designed (sized) for station maximum capacity and fluid disposal systems for respective capacities. For production fluid storage capacities, please refer to Appendix Y, Production Fluid Facility Capacity Tables. PG&E relies on offsite disposal of produced fluids and does not have disposal wells at any of the three owned and operated facilities.

14.5. Operating Pressure Range

Minimum withdrawal flow rates are established within the operating pressure range to lift fluid from the bottom of the well to the surface. Fluid production is necessary to allow the wells to continue production to meet customer demands. Each well shall have established well operating parameters within limits. This should include pressures and/or flow rates to minimize flows that could lift sand or erosion due to velocity.

14.6. Well Risk Ranking

The risks for each individual well are used develop risk scores based on likelihood and consequence of failure. These risk scores are used to rank wells relative to each other by risk on a well by well basis. The methodology and 2019 results are provided in the following companion documents:

- McDonald Island Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan
- Los Medanos Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan
- Pleasant Creek Underground Storage Field Well Risk Evaluation and Construction Standard Implementation Plan.

The above noted field specific plans are living documents and are refreshed annually for work planning and as needed based on continuous evaluation data received as part of the P&M measures outlined within this plan.

PG&E began initial baseline casing assessment evaluation in 2013 and as PG&E completes the baseline process, the risk score of a given well informs the priority of the wells addressed in the annual program. This targeted addressing wells with higher risk scores first. PG&E historically performed approximately six (6) to eight (8) reworks and/or assessments per year in alignment with the funding approved in the Gas Storage and Transmission (GT&S) rate cases. This was set to pace completion of baseline integrity assessments and reworking of wells with nonfunctioning DHSV and gravel pack on 99 wells by 2025. Beginning in 2019 and planned through 2025, the risk score of a given well informs the pace a well is converted to tubing and packer configuration to eliminate a single point of failure. The final well selection in each year's well work program additionally considers the schedule of reworks and the ability to effectively and efficiently conduct the work, minimization of unnecessary equipment mobilization, and other station projects that impact deliverability with an effort to reduce the amount of outage time at the storage facilities. The planned well units to convert each year are shown in Table 4 by field.

Table 3: Storage Rework and Retrofit Unit Schedule

Year	McDonald Island	Los Medanos	Pleasant Creek	Total
2019	10	2	1	13
2020	14	3	2	19
2021	14	3	2	19
2022	13	3	2	18
2023	13	3	-	16
2024	13	3	-	16
2025	10	3	-	13

As PG&E continues to perform baseline assessments and re-assessments more data will be available to further inform the efficacy review of other P&M programs across the well population. After wells are baseline assessed and converted to tubing and packer, a well's risk score will help inform prioritization of a full re-assessment in the target ranges explained in Appendix C and shown below:

- 3-5 Years OR consider additional investigations
- 5-8 Year Interval
- 8-12 Year Interval
- 12-15 Year Interval

Information about a well's condition that is gained during well work is updated accordingly within the risk model as it is a dynamic and updated through the continuous evaluation processes included in this Plan's Appendices and practices. The year over year comparison inclusive of reassessment cycle will aid in evaluating if a well's risk has changed and how effective controls and mitigations are.

15. Threat and Risk Management

Sections 15, 16 and 17 address the process used by GSAM to evaluate all potential threats, hazards and corresponding risks impacting storage wells and reservoirs. The process is generally consistent year-over-year and across all asset families within Gas Operations, but is also improved over time with GSAM, Gas Operations and industry experience. The risk management process is reported, monitored and documented as described in the following subsections of Section 15, 16, and 17.

PG&E's organizational structure facilitates the integration of risk management and investment planning. The risk management process provides the framework for evaluation of the likelihood of events and consequences related to threats and risks associated with operation of PG&E's underground gas storage, risk ranking to develop preventive and mitigating measures to monitor or reduce risk, documentation of risk evaluation and description of the basis for selection of preventive and mitigation measures, provision for data feedback and validation, and regular risk assessment reviews to update information and evaluate risk management effectiveness.

15.1. Organizational Structures that Facilitate the Integration of Risk Management and Investment Planning

PG&E's risk management governance structure consists of the following:

15.1.1. Nuclear, Operations, and Safety Committee

The Safety and Nuclear Oversight Committee (SNO) consists of at least three directors from PG&E's Board of Directors, one of whom is appointed as the Committee's chair. The basic responsibility of the SNO Committee is to provide oversight and review of (i) significant safety (including public and employee safety), operational performance, and compliance issues related to PG&E's nuclear, generation, gas and electric transmission, and gas and electric distribution operations and facilities, and (ii) risk management policies and practices related to operations and facilities.

15.1.2. Risk and Compliance Committee

The Risk and Compliance Committee (RCC) is chaired by the Gas Operations Senior Vice President, all Vice Presidents and all Senior Directors. This Committee meets monthly and reviews and approves Session D materials in addition to monitoring compliance and risk management activities. Furthermore, asset family owners (AFOs) present at least once a year on progress, issues, and next steps in their asset management plans.

15.1.3. Gas Operations Risk Management Organization

This organization is led by the Manager of Risk Management who reports to the Senior Director of Asset Knowledge and Integrity Management. This organization is responsible for leading the risk management process resulting in Session D (focused on risk) and the creation of the Gas Operations risk register. The risk management team, consisting of a manager and a number of risk analysts, is also responsible for ensuring that Gas Operations' risk management process is fully integrated and aligned with the integrated planning process.

15.1.5. Asset Family Structure

In mid-2012, PG&E's Gas Operations divided gas assets into asset families and designated an individual responsible for each family, referred to as an AFO, who is the single point of accountability for fully understanding and managing the health of the assets within the asset family. To help manage the diversity of these natural gas assets and as a foundational step in implementing an asset management system PG&E established eight separate asset families within its Gas Operations business consistent with Publicly Available Specification (PAS) 55 and International Organization for Standardization (ISO) 55001, and API 1173 standards as guidance. PG&E Gas Operations is in the process of adopting and implementing API Recommended Practice 754, Process Safety Performance Indicators. This Recommended Practice helps to identify key leading and lagging process safety indicators useful for driving performance improvement. The benefits of process safety performance indicators include:

- Increased assurance on risk management
- Demonstrated suitability of control systems
- Cost savings
  - Avoidance of discovering weaknesses through costly incidents
- Collecting and reporting on relevant performance information
- Provide relevant and useful information for decision-making.

PG&E's asset management system focuses on:

- Identifying and reducing operational and enterprise risk;
- Maintaining an asset management framework and directing organizational focus on the most important asset risks and opportunities;
- Proactively managing the condition of gas assets; and
- Meeting or exceeding the requirements of federal, state, and local codes, regulations and requirements in an environmentally sustainable manner.

The Gas Safety Excellence Policy (TD-01) lays the foundation for PG&E's Gas Asset Management system, while the vision and strategy for enhancing the system is documented in the Strategic Asset Management Plan. PG&E also maintains risk-based Asset Management Plans for each of its nine gas asset families. Finally, PG&E reports regularly to the California Public Utilities Commission (CPUC) on its safety and reliability investments.

The AFO is a subject matter expert (SME) on the particular type of asset and also has the ability to draw upon other resources within the company to better understand, assess, and manage that family of assets. Associating each asset with a family, and designating an AFO, helps Gas Operations to: (1) identify threats; (2) assess asset condition and risk quality; (3) identify and assess risks facing the assets; (4) develop and effectively execute mitigation efforts; and (5) follow a consistent process for managing assets and maintaining alignment across asset families. The AFO represents its asset family in the risk management and investment planning processes. Each AFO is also responsible for developing an asset management plan for their asset family.

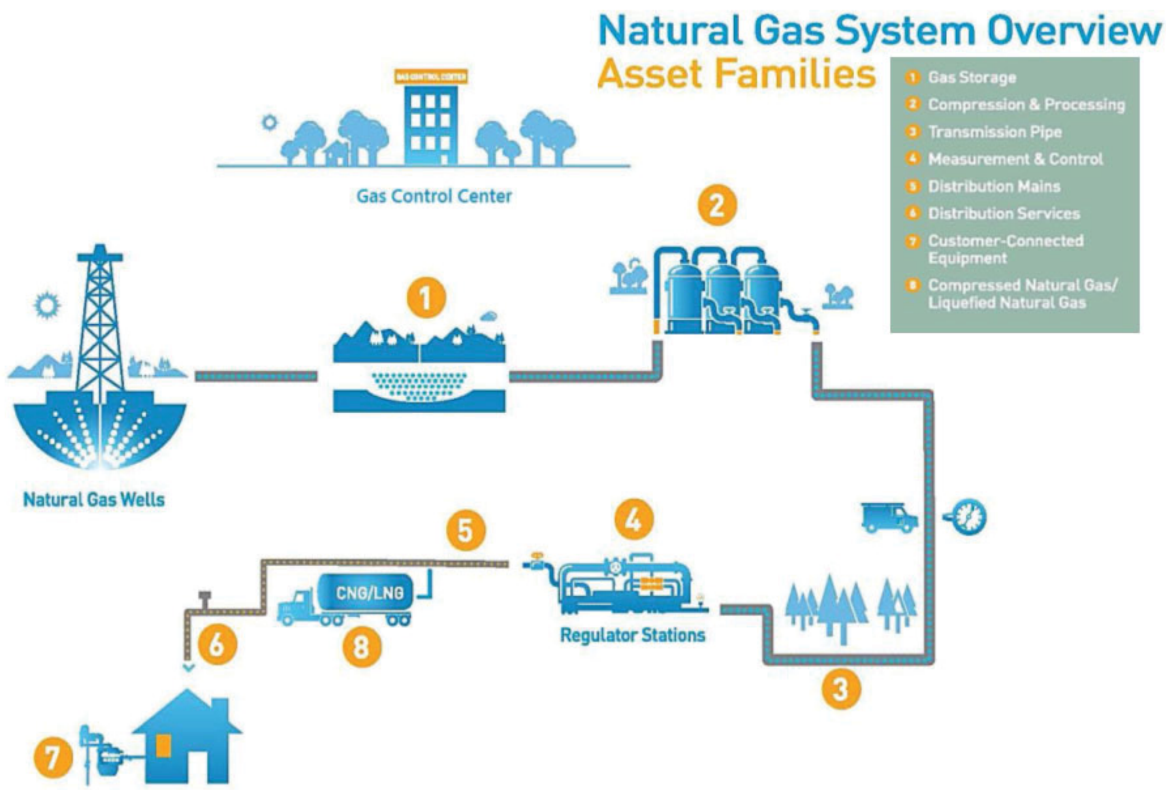


Figure 1. Gas Operations Asset Families

15.1.6. Investment Planning Organization

This organization is led by the Director of Investment Planning and Resource Management. This organization is responsible for portfolio-level prioritization across all assets and all programs. Investment Planning leads the process to develop a multi-year investment plan that is informed by risk and operational constraints. This process feeds directly into the forecast development for Session 1 (focused on strategy), Session 2 (focused on execution), and rate case filings.

15.2. Risk Management Process

This process is employed to determine susceptibility to threat and hazard-related events and to assess threat and hazard interaction.

Gas Operations has adopted a risk management process that provides a consistent and transparent method to identify, assess, rank, and mitigate risk and has integrated this process into the Gas Operations Investment Planning process, which allows Gas Operations to prioritize its investment portfolio based on risk and constraints. The Gas Operations risk management and investment planning processes are linked directly to the Enterprise and Operational Risk Management (EORM) Program and enterprise-wide integrated planning process.

The risk management process can be categorized into four major steps: (i) identify and assess threats to the assets; (ii) risk identification and evaluation; (iii) risk response; and (iv) risk monitoring and reporting.

15.2.1. Integrity Asset Threat Classification

Each AFO works with his/her team to identify the threats to the assets in their families. Typically, AFOs rely on the American Society of Mechanical Engineers (ASME) B31.8S standard as the basis for categorizing and evaluating threats to their assets. The standard identifies nine categories of threats, which are grouped into three main categories:

1. Stable or Resident

   These threats are either present or potentially inherent to the asset but do not grow over time or pose a threat unless influenced by another condition or failure mechanism, such as manufacturing defects influenced by land movement.

2. Time Dependent

   These threats, such as corrosion, are threats that potentially increase over time.

3. Time Independent

   These threats are not influenced by time such as third-party excavation damage, incorrect operations, or weather-related and outside force (e.g., natural forces).

AFOs complete a threat matrix that documents the data quality status of each threat and the status of the various proposed mitigation programs to address those threats.

An inventory of data that is available for use in assessing risks is presented in Appendix AA.

In addition to ASME B31.8S, the Gas Storage asset family uses the American Petroleum Institute Recommended Practice (API RP) 1171: Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. Potential threats or hazards identified for the wells, reservoir, and surface from API RP 1171 Table 1 Potential Threats and Consequences are listed in Table 4 below.

Table 4: Asset Type and Threats or Hazards

Asset Type	GSAM Threats or Hazards	API RP 1171 Threat
Wells	Corrosion / Erosion, Manufacturing, Equipment	Well integrity -- Gas containment failure due to inadequately sealed storage wells, e.g. casing corrosion, cement bond failure, material defect, valve failure, gasket failure, thread leaks, etc.
	Construction / Fabrication	Design -- gas containment failure due to inadequately completed wells, sealed plugged wells, failure of cement squeeze job perforations or stage tool, pressure rating of components, etc.
	Incorrect Operations (Operation and Maintenance)	O&M -- inadequate procedures, failure to follow procedures, inadequate training, and experienced personnel and/or supervision
	Incorrect Operations (Well Intervention)	Well intervention -- gas containment failure due to loss of control of the storage well drilling, reconditioning, stimulation, logging, working on downhole safety valves, etc.
	Refer to reservoir and surface elements on the threat matrix	Third party damage -- intentional/unintentional
	Refer to reservoir and surface elements on the threat matrix	Outside force -- natural causes. Weather-related and ground movement.
Reservoir	Construction / Fabrication, 1st, 2nd, 3rd Party Damage	Third party damage -- third-party drilling, completion, and work or activities. Third-party production, injection or disposal operations
	Outside Forces (Geologic Uncertainty)	Uncertainty of extensive reservoir boundary. Expansion, contraction and migration of storage gas. Failure of cap rock
	Incorrect Operations (Reservoir Fluid Compatibility Issues)	Contamination of storage reservoir by foreign influence

Asset Type	GSAM Threats or Hazards	API RP 1171 Threat
Surface	1st, 2nd, 3rd Party Damage (Surface Encroachments)	Surface encroachments
	1st, 2nd, 3rd Party Damage (Damage to Equipment)	Intentional/unintentional damage
	Weather & Outside Forces (Natural Causes)	Weather-related ground movement

Mitigations and prevention activities and guidance documents associated with threats are listed in Appendix X.

15.2.2. Risk Identification and Evaluation

Threats in each category of Table 5 above are considered in the development of the risk assessment. Any applicable threat should be considered even if shortcomings exist in the availability of data.

GSAM reviews the results of the risk assessment to determine whether the risk assessment, resulting prioritization or ranking represents its facilities and characterizes the risks. While no ASME B31.8S or API 1171 threats are excluded at this time, if it ever becomes appropriate to exclude any, this exclusion would be justified and documented in the supporting documentation for the threat matrix.

Having identified the various threats applicable to the asset family, each AFO works with subject matter experts (SMEs) and the Gas Operations' risk management team to identify the relative risk(s) which are based on events associated with the threats identified for the assets. Threats are assessed relative to individual facilities, such as wells, and by region when considering the reservoir.

A given threat may have the potential to give rise to or contribute to one or multiple risks. For example, the equipment-related threat results in a different risk for the Measurement and Control asset family than it does for the Distribution Mains and Services asset family.

<u>Risk Evaluation through 2018</u>

SMEs use available internal and external data, system knowledge, and subject matter expertise to determine the impact and frequency scores using the enterprise Risk Evaluation Tool (RET) to calculate a relative risk score for each risk. The basic components of the RET include:

1. The RET score is a product of the potential impact and the frequency of a risk event, while accounting for the current strength of current controls. Each risk event is

considered under a "probable worst case" scenario, otherwise known as a P95 scenario.

2. The potential impacts of the P95 scenario are scored across six impact categories – Safety, Environmental, Compliance, Reliability, Trust, and Financial. Each impact is scored from 1 (negligible impact) to 7 (catastrophic impact).

3. The potential frequency of the risk event is likewise given a score of between 1 (remote) to 7 (frequent).

4. A logarithmic scale is used in RET score calculations to increase differentiation between risks and provide a better view of the relative priority of risks.

5. A weighting factor for each category to indicate the relative importance of one category to another and ensure safety risks receive higher scores than non-safety risks, and as such, higher priority for mitigation consideration.

A series of calibration sessions occur at four levels where AFOs, SMEs, senior management, and officers have the opportunity to challenge and openly discuss the assumptions underlying the scores of the risks. The three levels of calibration are as follows:

1. The first level of calibration occurs for all risks within each asset family and includes AFOs, SMEs, and the Gas Operations risk management team.

2. The second level of calibration occurs for all risks across Gas Operations and includes AFOs, risk owners, SMEs, Gas Operations risk management team, and Gas Operations senior management.

3. The third level of calibration occurs at the enterprise level across all Lines of Businesses (LOBs).

4. The fourth level is a vertical slice calibration and occurs at the officer level for the enterprise.

The objectives of the calibration sessions are to improve consistency in the application of PG&E's risk model and SME input and judgment, and application of data, while continuously striving to improve repeatability and transparency. The calibrated risks are documented in the Gas Operations Risk Register, which is periodically updated and refined as additional information is obtained, reviewed, and evaluated.

Note, while PG&E's Enterprise Risk team is moving away from this risk assessment tool, the Storage Asset Family maintains and annually reviews the RET tool risk register with SME input.

Beginning in 2018 – Event Based Risk Analysis

The company is moving from a scenario focused risk register (RET) to a register that is defined per a risk event (BBRR).

A risk event is a mutually exclusive occurrence or change of a particular set of circumstances that may have potentially adverse consequences and may require action to address.

The risks described above are defined as “sub-drivers” that could result in an event with adverse consequences. The event currently defined under the scenario focused risk register for GSAM is:

- Loss of containment with ignition

The process described in the “Up Until 2018” section immediately above is still valid for the identification and assessment of risk subdrivers. An SME team representing a variety of disciplines applicable to GSAM are engaged to confirm the set of subdrivers is complete, and the influence these subdrivers have on the likelihood and consequences of events. Individual subdriver scoring is no longer part of the process, but the detailed understanding of risk subdrivers is still used to develop risk mitigation and control plans, since the detail provided at the subdriver level is consistent with the detail needed for this planning.

However, the higher level risk events in the list immediately above are used as the basis for evaluating risk severity at a corporate level, for the purposes of allocating resources equally across the corporation.

15.3. Risk Response – Development of Mitigation Programs

Using the identified and evaluated risks, AFOs and their teams then identify the appropriate risk response plan. A risk response plan includes a set of mitigations and corresponding metrics to reduce the risk, strengthen the controls, track the progress and assess the effectiveness of mitigations. This process is detailed below:

1. The first step of developing a risk response plan for a given risk is to determine the strategy. AFOs and SMEs identify if they want to reduce, accept, transfer, or avoid the risk.

2. As in most cases, if the plan’s strategy is to reduce the risk, then the next step involves AFOs and SMEs assessing the current controls to reduce that risk, and identifying any new potential mitigation. These mitigations are possible future processes, programs, assets, or controls that will reduce the risk.

3. Metrics are developed for the risks to help track progress of risk reduction and to evaluate the results of mitigation plans.

4. The mitigations are then submitted to Investment Planning for portfolio-level prioritization across all assets and all programs.

The risk response plan for key risks is documented in the Session D presentation material. The mitigations are also documented in the Asset Management Plans and in the initial preprioritized program submission to Investment Planning. Note that each of these outputs represents a snapshot in time; therefore, the risk response plans are likely different across these outputs.

15.4. Risk Reporting and Monitoring (Outputs and Documentation)

The processes described in Section 15 contain risk management activities that are conducted on a formal, annual cycle, however, the risk process including risk monitoring, risk management, assessments of risk management program effectiveness and improvement to risk management in general is continuous. If during the course of operations new threats or hazards are identified, or the impact of threats or hazards changes markedly, GSAM assesses the risk associated with new conditions and evaluates and prioritizes risk management options, metrics and monitoring frequencies in accordance with the risk assessment. These are key elements of maintaining the functional integrity of the storage operation.

The risk management process is reported, monitored and documented as described in the following subsections of Section 15.

15.4.1. Threat Matrix

A Threat Matrix is developed by the AFOs and AF staff to document key threats, the data quality status of each threat, and the status of the various proposed mitigation programs to address those threats and is documented within the Session D presentation. Any change to the threat matrix is reviewed and approved by the Risk and Compliance Committee.

15.4.2. Risk Register

Prior to 2018, the calibrated risk scores, justifications, and assumptions resulting from the risk refresh and Session D process were documented in the risk register. As described in Section 15.2, the risk register while no longer part of the formal process of risk reporting within Gas Operations is still of value in the development and continued review of risk subdrivers and corresponding risk mitigations and controls.

Low consequence risks managed by ongoing safety, reliability, capacity, compliance and other programs are not typically included in the risk register. For example, some support work such as minor building projects may not address a risk on the risk register but is considered in our integrated planning process. Risks in the risk register are mitigated by programs listed in the threat matrix.

15.4.3. Session D Presentation

The purpose of Session D is to communicate the top event-based risks to PG&E's senior leadership. These top risks represent high consequence, yet low frequency events that may occur as a result of the larger set of risk drivers and sub drivers (developed and documented in the RET).

Session D reflects an assessment of enterprise risks, operational risks and compliance risks. The Session D process kicks off at the end of the third quarter of each year and deliverables include a risk refresh, the Risk Register, a Session D presentation and an executive discussion among senior PG&E officers across all LOBs. At the annual Session D meeting, senior officers discuss: (1) the top risks for the company and for each LOB; (2) risk reduction or mitigation progress to date; (3) strategies to manage any risk mitigation challenges; (4) future risk management plans; and (5) areas where collaboration across LOBs or additional resources may be required to manage risk.

The information collected in Session D informs PG&E's strategy and execution plans that are developed in Sessions 1 and 2.

16. Asset Management Plans

Gas Operations documents the management of each asset family through an asset management plan (AMP). The AMPs are developed with a 5-year planning horizon to align with the Gas Operations 5-year financial outlook. They describe the: (1) physical assets of the respective asset family; (2) current condition and desired future state of the assets; (3) key risks associated with the asset family; and (4) investments planned or in progress to mitigate and reduce these risks. The AMPs also include key performance indicators, which are metrics intended to measure progress and improvement in asset performance and the effectiveness of mitigation programs.

AMPs are living documents evolving as new data becomes available or as risk management/control plans change. The AMPs are revised on an annual cycle. However, as described in Section 15.4 and in recognition of the dynamic process involved in identifying, assessing and mitigating risks, the assessment of risks and the development and implantation of risks mitigations and controls is a continuous process.

17. Prioritization of Risk Mitigation and Control Efforts

Risk mitigation and control efforts are prioritized based on potential severity of consequences and estimated likelihood of occurrence of each risk event. ~~threat.~~

17.1. Investment Planning Process

As described in Section 15.3, the AFOs submit a list of proposed mitigations to Investment Planning for portfolio-level prioritization across all assets and all programs. Investment Planning leads the process to develop a multi-year investment plan that is informed by risk. The objective of this prioritization is for Gas Operations to invest in its higher risks with the most effective mitigation programs given constraints including compliance obligations, obligations to serve, resources, system availability, executability, and cost. To accomplish this objective, Investment Planning leads the following steps, which include the Risk Informed Budget Allocation (RIBA) process:

17.1.1. Classification

The first step in the process is to classify projects or programs (for example reworks and integrity assessments, refer to Section 12.6: Well Risk Ranking). This step identifies the key drivers for the work, which are used during prioritization in concert with the risk scores of each project or program. Classifications include but are not limited to: Mandatory; Regulatory Compliance; Commitment; and Work at the Request of Others (WRO).

17.1.2. Program and Project Risk Scoring

The next step in the process is to risk score the respective projects or programs. It is important to note that there is a distinction in purpose between the Risk Register risk score, and the Program and Project risk score. The purpose of the Risk Register risk score is to rank and prioritize high consequence, low frequency risks at the asset level. The purpose of the Program and Project risk score is to relatively capture the consequence and likelihood scores for Safety, Environmental, and Reliability to determine the worst credible event that could occur if PG&E does not invest in the program or project. The program and project risk scoring process uses a framework to assess consequence and likelihood that is aligned with the framework utilized in the development of the Gas Operations Risk Register. The calculations are different; however, they are aligned, and that alignment is validated during the process as described in Section 14.1.3 below.

17.1.3. Program and Project Risk Score Validation

The next step is to validate the program and project risk score. To facilitate consistent application of risk scores within and across asset families, Investment Planning conducts calibration sessions. In addition, Investment Planning conducts analysis to validate that the program and project risk scores are aligned with the risk register risk scores.

17.1.4. Preliminary Portfolio

Based on the classification and calibrated risk scoring for projects or programs, Investment Planning builds a preliminary investment portfolio by first including all compliance, WRO, and commitment work and then by including programs ranked by their respective program and project risk score.

17.1.5. Constraints Analysis

Once the preliminary investment portfolio is compiled, Investment Planning collects information on constraints, including resources, system availability, and financials. Investment Planning then makes adjustments to the preliminary portfolio based on these constraints prior to the investment decision meetings.

17.1.6. Investment Decision Meetings

Investment Planning then conducts a series of Investment decision meetings with the AFOs and other stakeholders to analyze the portfolio and make any adjustments to the portfolio informed by risks and constraints. These adjustments are typically in the form of increases or decreases to the scope or pace of a program. Investment Planning is responsible for providing portfolio analysis and facilitating the meetings; however, AFOs are accountable for making the investment decisions.

17.1.7. Investment Plan Approval and Reporting (Outputs and Documentation)

The Investment Planning process and deliverables are documented and reported in the following key outputs and forums.

17.1.8. Program and Project Scoring Sheets

A Program and Project Scoring Sheet is generated for each program considered in the Investment Planning process. The purpose of the program and project scoring sheets is to document and display pertinent information for each program including the classification, program and project risk score along with justifications, rate case forecast iterations throughout the forecast development process, and alignment to Session D.

17.1.9. RIBA Charts

The RIBA charts are a visual representation of the output of the Investment Planning process, which display: program cost; program and project risk score; and respective classification.

17.2. Investment Planning Summary

PG&E presents its forecast in rate cases being informed by risk. The work proposed represents an appropriate balance of cost and risk reduction over time, based on the resources available, while maintaining the ability to deliver gas to customers. The RIBA process provides a means of making expenditure decisions that are risk-informed while considering other important factors. Lastly, both the EORM Program and RIBA process involve personnel who are most familiar with the condition of assets and ensures that all levels of management are engaged. The rate cases propose a set of programs that will set PG&E on the right course to continue reducing the risk profile of PG&E's natural gas assets for years to come.

17.3. Risk Management Records

PG&E's guidance document regarding records management and retention, GOV-7102S, "Enterprise Records and Information Management Standard", contains requirements that are applied to all GSAM records.

Refer to Section 23 of this plan for records management, and Appendix AA for a detailed mapping or records to record owners.

19. Abnormal Operating Conditions

19.1. AOC Definition

GSAM adopts the definition provided by PHMSA of an abnormal operating condition (AOC):

> A condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:
>
> - Indicate a condition exceeding design limits; or
> - Results in a hazard(s) to persons, property, or the environment.
> - Indicate a potential downhole problem not related to design or hazard(s) but that may risk the integrity of the well and/or reservoir.

In addition, a condition that is abnormal or potentially a non-conformance may be considered as an AOC and documented as such, even though it is judged to present no hazard or to exceed no design limit. Documenting these for trending and further assessment processes is encouraged.

19.2. Overview

AOCs are addressed in a number of procedures throughout this document, and in the Gas Operations guidance documents employed by GPOM in the maintenance and operation of storage field related assets. Refer to TD-4800S, Continuing Surveillance.

AOCs and corresponding assessments shall be documented by GSAM either as set forth in Section 21 Change Control in situations where an AOC requires a deviation, or in the project file for situations that are addressed by existing guidance documents.

Process hazard assessments shall contain assessments of applicable AOCs. In addition, pre-startup safety reviews and other safety review/assessment elements of managing storage assets may all contain elements of the recognition and treatment of AOCs.

Periodic reviews of documented abnormal operating conditions shall be conducted for the purpose of establishing trends or lessons learned and modifying existing procedures to prevent recurrence.

- A central element of this process is a review of the process hazard assessment that is conducted of the wells and well work, and a periodic review as new information emerges through PG&E’s operations or industry knowledge.
- A review of well work AOCs shall be included in the formal contractor critique meetings that constitute reviews of the season well work upon conclusion of the well work.
- GSAM shall also conduct a periodic review of reservoir operations AOCs, typically logged by GPOM as corrective notifications in SAP. This may be done in conjunction with Station Engineering.

As set forth in Appendix AG, Section 4, AOC notification and documentation, contractors are to be instructed that they must notify GCSPM of the all incidents or injuries immediately. Notification must occur to both WSM and GCSPM and a follow up report must be received within 24 hours of the incident.

19.3. Example AOCs

Process hazard assessments conducted of well work contain a variety of "what if" conditions that can constitute AOCs, and can result in hazards and consequences. These serve as examples of AOCs.

AOCs do not necessarily present increased hazards. Some PHMSA publications characterize AOCs as a non-emergency conditions in which some design limit has been exceeded, or simply a variation from normal operations.

GSAM will rely on its SMEs to determine whether and AOC has arisen, based on the guidance in Section 18.

20. Emergency Response / Emergency Preparedness

This section introduces the emergency preparedness / response plans to address accidental loss of containment, equipment failures, natural disasters, and third-party emergencies.

Emergency response and preparedness are addressed in several areas within this plan, and in companion documents to this plan. Together these plans represent the integration of PG&E's gas pipeline and storage operations.

20.1. Addressed in Companion Documents

Gas Emergency Response Plan (GERP) EMER-3003M – This is the primary emergency operations guidance document applicable across all of Gas Operations.

- Utility Standard: EMER-6010S - Gas Emergency Response Plan Training, Exercise, and Evaluation
- Utility Standard: EMER-1010S - Maintaining and Updating Emergency Response Plans
- The GERP meets all requirements mandated by government regulatory entities, in order to minimize the hazard resulting from a gas pipeline emergency.
- Gas Operations personnel with emergency response responsibilities receive both training on GERP content, and participate in periodic exercises to develop and test personnel competency, and to confirm or identify needs for revisions to GERP content. Records of personnel training and testing, and records of these exercises are maintained by the Gas Emergency Preparedness (GEP) Department in Gas Operations.

Well Control Tactical Considerations Plan (WCTCP) is created by GSAM, is published by GEP as an appendix within the GERP, and is the GSAM blowout contingency plan that includes site-specific surface intervention and relief well plans.

Emergency Response Table-Top Exercise Plan

- This plan ensures that applicable staff receives training in the use of the emergency preparedness / response plans, and that personnel are familiar with emergency plans and procedures.
- GEP manages the overall exercise.
- The exercise is designed to test the effectiveness of the emergency preparedness / response plans (WCTCP and GERP).
- The emergency response exercise is scheduled and facilitated by the GEP Department and consists of creation of emergency scenario, rehearsal but emergency response personnel of operations and activities to address the scenario, and critical review of emergency response plan effectiveness and personnel familiarity and performance under the emergency response plan.
    - Operating and engineer personnel who hold responsibilities to act during emergency events have current training and practice on their emergency response roles. Documentation of emergency response responsibilities for GSAM employees is included in the WCTCP.
    - GEP, GSAM and GPOM SMEs judge (and document in the exercise report)
        - The familiarity of emergency response personnel to the emergency response plans, and the performance of emergency response personnel, to either confirm capabilities are as desired, or to identify where capabilities need to be strengthened further, and develop and implement plans accordingly. Documentation of emergency response familiarity and capabilities is included in the post-exercise report.
        - The effectiveness of the emergency response guidance documents to either confirm document effectiveness is as desired, or to identify where guidance documents need to be revised to achieve the desired level of effectiveness. Documentation of emergency response plan effectiveness is included in the post-exercise report issued by GEP. Emergency response plan improvements desired as a result of the exercise are managed through PG&E's Corrective Action Program (CAP).

Blowout Prevention in California - Equipment Selection and Testing (DOGGR blowout prevention practice) - This is a guide for CA Division of Oil, Gas, and Geothermal Resources engineers and operators of Wells in California. The manual is designed to help operator personnel in planning their well operations. By serving as a single-source guide to blowout prevention equipment (BOPE) used in oil, gas, and geothermal operations in California, the manual will help operators conform to the BOPE requirements of the Public Resources Code and the California Code of Regulations. The manual is oriented primarily toward the equipment involved in blowout prevention.

Rig Evacuation Procedure (Appendix AD). This procedure is developed and owned by GSAM, and applies to personnel working on a drilling rig.

<u>Facility Evacuation Plan</u> These are maintained by GPOM for each of PG&E's three storage fields and address the evacuation of personnel from facilities on site and from the entire site.

<u>Pre-Fire Safety Plan</u> (for Fire Department) owned by GPOM for each site.

21. Security

Security at PG&E gas storage assets including limiting access to storage fields in general, and storage wells during drilling, workover, operation, and abandonment activities is accomplished in accordance with the following standards, plans, and guidelines. Collectively, these comprise the site security risk mitigation program.

- Utility Standard: TD-4050S Security Standard for Gas Operations is the primary guidance document.
- PG&E TD-4800S, Continuing Surveillance
- North American Electric Reliability Corporation (NERC) tier 1 standard / penetration testing checklist and procedure may be used periodically by PG&E Corporate Security to inspect security measures at storage facilities.
- TSA Pipeline Security Guidelines, April 2018.
- General requirements for design and construction of fences and gates are in located in Numbered Document L-50, “Property Fence and Gates.
- Appendix AF of this IMP (signage)
- McDonald Island Security Plan 9/9/2010
- Los Medanos Security Plan 3/1/2010 updated 4/18/2013
- Pleasant Creek Security Plan – Relies on TD-4050S since this has not been designated as a critical gas facility until 2017. Development of a site-specific plan to be considered in 2018.
- Threat Vulnerability Assessment - McDonald Island, February 2018
- SEC-2001S Physical Security Program Standard
- SEC-2002S Visitor Escort and Employee Access Controls Standard

When used at well locations, fences or enclosures shall comply with applicable fire codes and regulations.

Plans are developed by Gas Operations in conjunction with PG&E’s Corporate Security Department. GPOM as the lead operating organization for the storage fields is responsible for implementation of the security plans with Corporate Security.

Site inspections for review of safety and security assurance are performed by:

- GPOM to verify that requirements of this section are met and maintained.
- Corporate Security, using any of the guidance documents listed above.

PG&E may employ additional measures to enhance site security based on an analysis of site-specific factors.

Well work program documents and well procedure and safety kickoff presentations developed by GPOM, PG&E Gas Contractor Safety Program Management and GSAM address the process to limit access to storage wells during drilling, workover, operation, and abandonment activities. These are supplemental to standard GPOM and Corporate Security Department security procedures applicable to each storage facility.

In addition, sources of ignition and flammable-type equipment and materials should be located in a manner to provide for the ongoing safety at the wellhead or well site. These guidance documents are adopted as addressing this requirement for well sites:

- TD-4640P-01 that addresses hot work
- TD-4551P-07 that addresses hazardous area classification
- TD-4430P-02 that covers general major gas transmission station maintenance, and includes general requirements for locating flammable material at compressor stations.

21.1. Access Roads

Access roads shall be maintained by GPOM in a condition that permits personnel and equipment access to the wells.

- Storage facility roads on PG&E's property by ownership or property leased by PG&E are maintained by GPOM.
- The condition of storage facility access roads owned by others, such a counties or reclamation boards, is monitored by GPOM. If conditions are judged by PG&E to be unsatisfactory, PG&E shall take the steps necessary to achieve satisfactory condition.

22. Change Control

Change control is performed to manage change. For the purposes of the change control program, a "change" is an activity that results in a difference between the current state and a future state by addition, modification, or substitution of processes, equipment, facilities, personnel, or procedures.

Change control guidance is provided in the following documents listed in Table 6. Technical discussion and justification for an MOC may also be documented in published whitepaper. Published GSAM whitepapers are approved and housed using PG&E's Electronic Document Routing System (EDRS).

Appendix AC, Gas Storage Asset Management – Change Control for Well Rework Process provides guidance for managing changes required during well rework activity and categorizes the level of MOC required as Category 1, Category 2, or Category 3 based on the change type required. The qualifying activity is provided in Appendix AC. Gas Operations utility procedure form TD-4014P-01-F01 is used to document changes for Category 2 and Category 3.

Table 5 - Change Control Guidance Documents

Document / Form	Description / Application
Gas Operations guidance document: Utility **Standard**: TD-4014S - Change Control (Management of Change) (TD-4014S.pdf or some version of this)	Standard describes the structure and requirements of the PG&E system for Gas Operations change control (Management of Change) to mitigate safety, health, and environmental risks.
Gas Operations guidance document: Utility **Procedure** TD-4001-P01 - Procedural Change	Procedure for applying MoC to procedures
Gas Operations guidance document: TD-4001-P04 - Tools/Equipment Change	Procedure for applying MoC to tools and equipment changes
Gas Operations guidance document: Utility **Procedure** TD-4014P-01 - Field Change Control Process (TD-4014P-01.pdf or some version of this)	Provides guidance for change control across Gas Operations. This is used for GSAM process and guidance changes other than those set forth further below, and is intended for "…changes such as facility design, facility operation/maintenance, assets, guidance documents, organizational structure, suppliers/contractors, and tools and equipment." The Gas Operations Process Safety Department is the content owner.
Gas Operations guidance document - MoC form associated with the procedure above. Field Change Control **Form** from Gas Operations Procedure TD-4014P. (MoC Form D-4014P-01-FO1, Rev. 1.docx or some version of this)	Form published by Gas Operations Process Safety Department used to guide the assessment of and to document changes described above. Completed forms are filed with the Gas Operations Process Safety Department.
Appendix AC, GSAM - Change control for well rework process	Guidance document for GSAM and is included in this document as Appendix AC.
MoC Log	This is an index of MoCs created in GSAM that resides in the GSAM MoC folder on the shared drive It is also the source for GSAM MoC numbers that are part of the catalog systems for MoCs.
Manned Stations Operational Change Control Process	Guidance document for MoC for GPOM station operations at McDonald Island and Los Medanos. Maintained by Gas System Operations.

23. Communication Plan

23.1. Internal Communications

GSAM personnel are responsible for preparing and communicating guidelines for maintaining reservoir and well functional integrity, including but not limited to the following:

- GSAM develops and maintains guidance documents specific to storage well and reservoir assets, and develops or confirm storage-specific content for guidance documents that are developed by the Gas Operations Guidance Documents and Engineering Services Department or elsewhere in Gas Operations. An index of guidance documents applicable to storage operations is provided in Appendix AA.
- GSAM provides access to guidance documents as set forth in the Target Audience Section 2.
- GSAM takes the initiative to communicate storage-specific guidance document content to storage engineering and operations personnel, contract personnel and personnel elsewhere in Gas Operations (e.g., GPOM, Gas System Operations). These activities are documented as remarks and attendance lists in well work project kickoff meeting reports correspondence transmitting revised guidance documents to the target audience, five-minute meeting guidance that is provided to the target audience, etc. documentation is maintained in the project or facility files in the GSAM shared drive.
- Provides technical peer review of the results of Gas Operations personnel operating, inspection, data gathering and data reporting activities regarding gas storage assets, to not only use the information in managing storage operations, but also to ensure that Gas Operations personnel understand and can perform as required as set forth in the guidance documents affecting storage assets. These activities are documented as correspondence requesting additional or revise data, and filed in the shared drive folder for that asset.

23.2. External Communications

Table 7 below summarizes a schedule of deliverables to be submitted regarding risk assessment results and operations.

Table 6: Schedule of External Notifications and Reports

Deliverable	Schedule	Agency
Identified anomalies	Immediately	DOGGR
Yearly Storage Well Evaluation Report	Annually by January 31	DOGGR
Gas Injection and Production Reports	Monthly	DOGGR
Water Production Report	Quarterly	DOGGR
Inventory Verification Report (by field)	Annually by November 30	DOGGR
Asset Management Plan	Annually by September 30	DOGGR

Deliverable	Schedule	Agency
Annual Production Report	Annually by March 15	DOGGR
Annual PHMSA report	Annually by March 15	PHMSA
Incident Report – F7100.2 & Supplemental Incident Report	As needed, as soon as practicable, not to exceed 30 days after detection	PHMSA
Construction Notification of new underground natural gas storage facility or the abandonment, drilling, or well workover (including replacement of wellhead, tubing, or a new casing) of an injection withdrawal, monitoring, or observation well for an underground natural gas storage facility.	As needed, 60 days prior	PHMSA
Acquisition or divestiture of an existing underground natural gas storage facility	As needed, no later than 60 days after	PHMSA

24. Records

The guidance below is meant to supplement and in compliance with:

- GOV-7101S: Enterprise Records and Information Management Standard

A complete set of records supports GSAM's efforts to determine susceptibility to threat and hazard-related events and to assess threat and hazard interaction. Inspections, tests, patrols, or analyses shall be documented according to this plan, GOV-7101S, and documentation requirements in guidance documents used by PG&E outside of GSAM. This includes records that demonstrate compliance with PHMSA for training. All records are retained in accordance with the Enterprise Record Retention Schedule (ERRS) included in GOV-7101S.

Records include but are not limited to the set presented in Appendix AA.

Records retained shall include superseded procedures.

RECORDS STORAGE

Records listed in Appendix AA for GSAM are stored on the GSAM shared drive. Detailed organization is best understood by reviewing the shared drive directory tree system.

- Records specific to a storage field are stored in a subdirectory for that storage field.
- Records specific to a single well are stored by well number.
- Equipment manufacturer documentation such as drawings, manuals or procedures are stored in two locations
  - GSAM shared drive in the folder for the associated GSAM asset.
  - Gas Operations records system (Documentum), managed by EDRM.

Examples include documentation for wellhead manual valves, uphole safety valves and downhole safety valves.

- Management of change documentation created by GSAM for well work (refer to Section 18 of this plan).

MoC records for GSAM other than well work are retained by the Gas Operations Process Safety Department.

Records listed in Appendix AA for other PG&E organizations are stored in hard copy and/or electronic form in systems maintained by those organizations.

In cases where GSAM is not in possession of the electronic source document, hardcopy records shall be scanned and stored in the appropriate folder in the GSAM shared drive. Examples include:

- Documents from regulatory agencies such as permits, audit results, etc.
- Management of change documentation (forms) that are filled in with handwriting (e.g., GSAM Field Change Control Form).
- Manufacturer foreign print files.

OBSOLETE RECORDS

In general, all records are preserved for the life of the asset and archived if the asset is removed from service. Exceptions must be approved by the GSAM director as follows:

When an asset is removed from service permanently or if the asset owner identifies records that are no longer required for compliance, maintenance and operational, or business needs, the following must be performed:

1. Identify all copies of documents or records, electronic or hardcopy.
2. Present list of documents and/or records and obtain approval from asset owner (GSAM Director) to obsolete documents and/or records.
3. Once approval has been obtained, dispose of any hardcopies in secure PG&E record disposal bin or request approved shred services to securely dispose of record to ensure confidentiality of records is obtained.
4. If using an approved shredding provider, request signed records destruction form and scan copy of form. Add to appropriate GSAM shared drive.
5. Request other PG&E departments (e.g., GPOM) to obsolete drawings records if available.
6. Remove and delete electronic forms from the GSAM SharePoint

26. Internal Auditing

Internal auditing is viewed as accomplished in two parallel methods

1. Auditing may be conducted periodically of the performance of GSAM and other PG&E organizations relative to the requirements of this and other guidance documents applicable to gas storage assets, engineering, maintenance and operations.

2. Auditing is conducted as a normal course of daily activities by SMEs, through formal and informal inspections and assessments described throughout this IMP.

3. Testing and training of employees and contract personnel is also considered a form of auditing – it confirms personnel competency and leads to competency improvements as appropriate.

These processes are used to confirm that PG&E is complying with requirements across all procedures, practices and other guidance documents, and to identify opportunities to make improvements to correct activities if either needed or beneficial.

Audits are also required to be made of the work being done by storage personnel to determine the adequacy and effectiveness of the procedures used in normal operation and maintenance of storage facilities. These audits support the continuous improvement of guidance documents (ref Section 5).

The frequency for internal audit is determined in accordance with risk assessment practices addressed throughout this IMP. For example, highest-risk activities for which a solid understanding is not held for guidance document or human performance effectiveness deserve the highest priority for internal audits, and may be the subject of continuous review during the normal course of maintenance and operations activities.

Audits may be initiated by any PG&E organization but shall always involve GSAM leadership and staff. Audits may be conducted by PG&E or qualified third-party experts.

Audit results and findings shall be documented in a post-audit report, and reports shall be filed in the GSAM shared drive. Simple actions undertaken and completed promptly to correct aspects of storage asset management may be documented simply in revisions to the audit report. Actions that may require more substantial effort or that make take time to resolve shall be documented in and managed through PG&E's Corrective Action Program.

Audit findings that require PG&E to self-report to regulatory agencies shall be handled through PG&E's self-reporting process, administered by the Gas Operations Compliance Department.

26.1. GSAM Engineering

GSAM Engineering performs the follow as part of routine work:

- Constant auditing of storage operations through procedures set forth throughout this IMP.

- Informal site inspections/auditing at storage fields.
- Oversight auditing of GSAM reservoir specialist personnel.
- Auditing/review of storage reservoir and equipment operations including defects or issues identified by GSAM reservoir specialist personnel or GPOM.
- Periodic auditing review of emergency response plans
  - GERP annual review/update cycle
  - Storage field-specific emergency response plans

26.2. QA Department

Gas Operations QA department audits work done by GPOM under various sections in this IMP as part of the routine QA processes within Gas Operations. GSAM may provide guidance to QA to help clarify what needs to be audited.

26.3. Corporate Security

CS auditing activities consist of

- periodic reviews of physical security
- Prepares and periodically updates security vulnerability assessments (requirement in site-specific security plans)
- Ensures facility is compliant with protection of sensitive information (requirement in site-specific security plans).
- Ensures facility is compliant with the latest security guidelines, directives and policies (requirement in site-specific security plans).

END of Requirements

27. Compliance Requirement / Regulatory Commitment

PHMSA Interim Final Rule for critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities.

On December 19, 2016, PHMSA published in the Federal Register an interim final rule (IFR) that revises the Federal pipeline safety regulations to address critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities. This IFR responds to Section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, which was enacted following the serious natural gas leak at the Aliso Canyon facility in California on October 23, 2015. This IFR incorporates by reference two American Petroleum Institute (API) Recommended Practices (RP): (1) API RP 1170, "Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage," issued in July 2015, and (2) API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," issued in September 2015.

California Code of Regulations Title 14, Division 2, Chapter 4.

28. Document Contacts

Document Approver

Larry Kennedy

Document Owner

Larry Kennedy

Document Contact

Lucy Redmond

29. Revision Notes / Change Log

Changes to this plan are to be accomplished in a controlled manner, with the use of the Gas Operations change control process (ref guidance documents TD-4014S Change Control Standard and TD-4001-P01 Procedural Change).

The following documents changes of significance made to this plan.

Date / Document Edition	Change Summary / Description
August 2016	Published for use as a new document
July 18, 2017	Published a revised edition.
September 29, 2017	Published a revised edition.
January 18, 2018	Revised and published to conform to IFR requirements for elements to be in place by 1/18/18.
April 02, 2018	Revised to add content needed for well work program beginning in April 2018. Refer to compliance Masterfile for details. IFRcomplianceMasterfile032818.xlsx
March 29, 2019	Revision 5 published with changes to multiple sections for continued implementation of PHMSA IFR and DOGGR Final Regulations.

Appendix A, Well Logging Criteria for New Wells

Page 1 of 2

The following table of logs should be consideration newly drilled storage wells (vertical).

Table A-1: Logs to Consider for Newly Drilled Storage Wells (Vertical)

Type of Log	Principle	Identification
Array Induction	A high frequency current of constant intensity is sent through a transmitter coil. The magnetic field induces currents in the formation surrounding the borehole. The currents are proportional to the conductivity of the formation.	Deep formation investigation to minimize borehole influences and measure resistivities. Fluid Contacts. Water Saturation.
Density	Medium energy gamma rays are emitted to the formation and scattered, if the formation is very dense the more scattering takes place and more gamma rays are absorbed, less dense formation the less scattering and less absorption.	Primarily used to measure bulk density. Can be related to porosity when lithology is known, gas detection, hydrocarbon density, and evaluation of shaly sands.
Compensated Neutron Logs (“CNL”)	Neutron logs measure the formation’s ability to slow the movement of neutrons through the formation. This measurement reflects the amount of hydrogen in the formation indicating the porosity of the formation. This log requires a fluid filled hole.	The compensated neutron log is recorded as apparent limestone, sandstone or dolomite porosity. It has the advantage of reduced borehole influences and is used to evaluate formation porosity and identify gas zones and gas/liquid contacts.
Gamma-ray (“GR”)	Gamma-ray logs measure the natural gamma radiation	Used to identify lithology (distinguish shales from sandstones and carbonates). Also used for geologic correlations and for calculating the volume of shale in sandstone.
Spontaneous Potential (“SP”)	The SP curve records the electrical potential produced by the interaction of formation water, conductive drilling fluid, shales.	The SP is used to identify permeable beds, locate boundaries of permeable beds, aid in determining water resistivity and as an indicator of formation shaliness.
Resistivity Logs	Electric current is passed through the formation, and voltages are measured between electrodes. The measured voltages provide the resistivity.	Various formation resistivities are calculated: flush zone, uninvaded zones, fluid contacts and water saturation.
Microlog (“ML”)	Electric current is passed through the formation, and voltages are measured between two short-spaced electrodes with different depths of investigation. The measured voltages provide the resistivity	Comparison of the curves identifies mudcake which indicates invaded zones, thus permeable formations

Underground Storage Risk and Integrity Management Plan

Cased Hole Logs

The following table lists types of logs to run in cased hole conditions. Note, additional logs not included in this list may also be considered.

Table A-2: Type of Cased Hole Logs

Type of Log	Principle	Identification
Casing Inspection Tools	The tool uses magnetic flux leakage or ultrasonic measurements to identify corrosion and defects in casing	Evaluation of casing apparent metal loss or gain and internal or external corrosion defects
CBL-VDL (casing bond and variable density log)	The principle of the measurement is to record the transit time and attenuation of an acoustic signal after moving though the borehole fluid and the casing wall. This log requires a fluid filled hole.	The CBL is used to evaluate hydraulic seal, cement to casing bond and coverage. The VDL is used to assess the cement to formation bond and to detect the presence of channels and gas intrusion.
CMT or CET (cement mapping or cement evaluation tool) or SBT	The tool uses the casing resonance in its thickness mode to give a very fine resolution.	The tool is used to identify cement presence and quality.
CCL (casing collar log)	The CCL is a magnetic device which is sensitive to the increased metal at a casing collar.	It is run with cased hole logs and is primarily used for depth control.
GRN (gamma ray-neutron)	Gamma ray logs record the natural radioactivity of the formation, less dense formations will appear to be slightly more radioactive.	The GR is used for correlation and gives lithology control. Neutron identifies gas behind pipe, porosity and fluid contacts.
Pulse Neutron	Tool measures response of various formations to the emission of generated nuetrons.	The tool determines reservoir saturation, porosity, and borehole fluid.
Thru-tubing	Base on pulsed eddy current(PEC) physics principles.	The tool measures the response decay of the eddy current signals and can provide metal thickness information for multiple concentric strings of pipe.

Appendix B, Additional Investigations

Page 1 of 2

A. Check well's cement bond log – top of cement and bond quality

1. If no bond log exists, consider cost/benefit to obtaining one.
2. Have there been any squeeze efforts or related cement improvement or remediation efforts?
3. Any temperature surveys?

B. Check well's nuclear log history

1. Gamma-neutron, pulsed neutron or other nuclear log
2. Noise, temperature, flowlog, or production/problem assessment log
3. Obtain annular fluid levels (AFL) and AFL history
4. Review logs for any prior history of annular gas or gas out of zone (occurrences adjacent to collars or to DV tools; correspondence to areas of inspection survey defects)

C. Check well's casing inspection history

1. Type of survey, compare survey results to present log
2. Have there been other integrity surveys run (magnelog, cathodic profile logging?)

D. Review well records for construction and rework history

1. When was casing installed; scratchers or centralizers, other external or internal tools applied
2. Any milling/drilling/spudding/cabling inside the casing
3. Any casing pressure tests or mechanical integrity tests
4. Cementing operations
5. Size, cement, problems or surface and intermediate casing strings
6. Natural hydrocarbon zones encountered while drilling
7. Other fluid flow or lost circulation zones encountered while drilling

8. Perforations

9. Stimulation treatments

10. Position of well in transmission pipe system; position relative to cathodic protection system rectifiers and anodes

E. Review well's annulus pressure history

1. Occurrences of pressure or flow

2. Other external evidence of problems (water well surveys, vegetation stress issues, odors, audible leaks reported, regulatory citations)

If a well's file is deficient in a number of items listed above and the well's inspection survey shows defects increasing in magnitude and/or extent, appropriate logs should be run, or tests and offset data should be obtained to help assess the problem and promote solution.

If internal corrosion is evident from survey, mechanical caliper and/or video camera surveys should be run at earliest possible convenience to confirm presence and magnitude of internal metal loss.

Underground Storage Risk and Integrity Management Plan

Appendix C, Casing Inspection Survey Frequency Decision Tree

Page 1 of 3

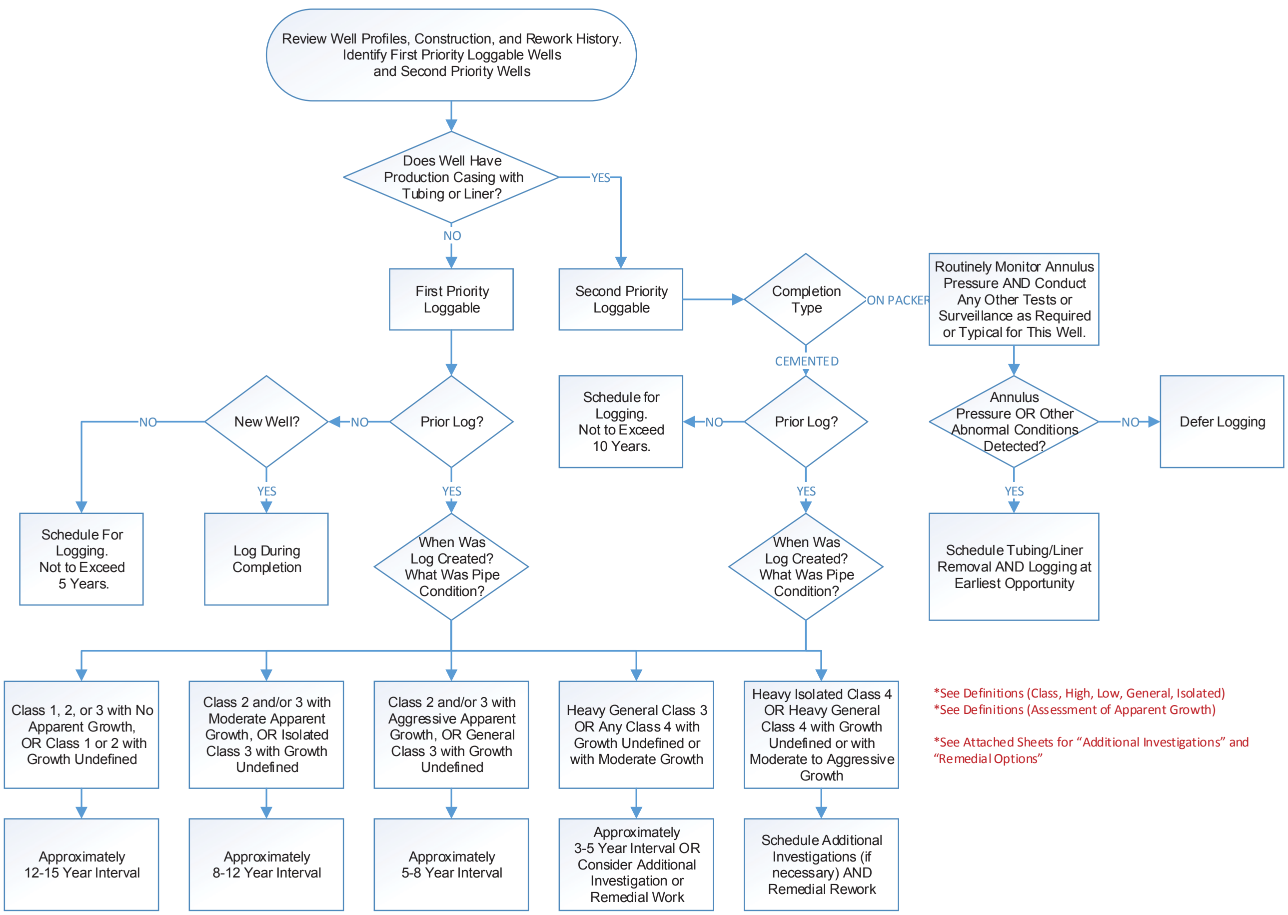


Figure C-1. Casing Inspection Survey Frequency Decision Tree

Underground Storage Risk and Integrity Management Plan

Definitions – Class, High, Low, General, Isolated

Class

Defect rating based on interpreted percentage of pipe wall thickness lost;
Class 1: <= 20% wall loss
Class 2: > 20% wall loss and <= 40% wall loss
Class 3: > 40% wall loss and <= 60% wall loss
Class 4: > 60% wall loss

High

In the upper 50% of the Class

Low

In the lower 50% of the Class

General

Many defects along the axis and/or circumference of the casing;
Baker/Atlas generally considers defect clusters appearing in nearly 40% or more of the sensors to be "general corrosion"

Isolated

Single flux leakage anomalies found by individual sensors or at most on less than 30 – 40% of sensors (which may be adjacent defects or single larger defects)

Internal

Anomalies on the internal wall of the casing, identified by eddy current anomalies corresponding to flux leakage anomalies on the same sensor pads; generally, the eddy current anomaly should have a signature or response level beyond background noise for any joint of casing

Outer or External

Anomalies on the external or outside wall of the casing. Identified by lack of eddy current anomalies on the same sensor pads.

Underground Storage Risk and Integrity Management Plan

Definitions – Assessment of Apparent Growth

To be used when comparing a survey log to prior survey logs

Pit Depth

Interpretations of metal loss from flux leakage measurements are at best within +/- 10 – 15% of actual metal loss (this could be closer to 10 – 15% for isolated pitting and 15 – 20% for general corrosion)

Therefore, let WTp = percent metal loss in present survey
WTn = percent metal loss in earlier survey
Yp = year of present survey
Yn = year of earlier survey

Then,

Maximum Rate of Apparent Change is:
[(WTp + 15%) – (WTn – 15%)] / (Yp – Yn)

And Minimum Rate of Apparent Change is:
[(WTp – 15%) – (WTn + 15%)] / (Yp – Yn)

Rates of Change > 3 – 4% + wall thickness per year = AGGRESSIVE
Rates of Change in the 1 – 3% wall thickness per year = MODERATE
Rates of Change < 1% wall thickness per year = LOW

Holistic Qualitative Review of Anomaly Occurrence and Density

In comparing the present survey to an earlier survey, does there appear to be a greater number of defects, a greater density of defect, or a growth in the circumferential or axial extent of defects?

How does the present survey compare to prior surveys in regard to eddy current anomalies or response to casing jewelry (scratchers, centralizers, etc.)?

Appendix D, Remedial Options and Decision Tree

Page 1 of 2

A. Remedial Options

1. Note: Any pipe recovered in remedial operations should be inspected and selected pieces set aside for delivery to Applied Technology Services (ATS) for detailed metallographic analysis and pit depth measurement. They may:

   a Clean and photograph the pipe.
   b Measure pit depth and geometry
   c Measure unaltered pipe wall thickness
   d Perform tensile tests on unaltered pieces of casing

2. Also note: Make sure that casing conditions have been properly assessed to remove the influence of conditions on log interpretation:

   a Does casing need to be washed prior to logging? (past history may indicate a need)
   b Were significant defect areas repeated?
   c Were all background checks and cross checks made against well construction data and rework records?

B. Remediation Decisions

1. Based on metal loss and geometry interpretation from casing inspection logs.

2. Compared to previous survey to establish rough approximate metal loss.

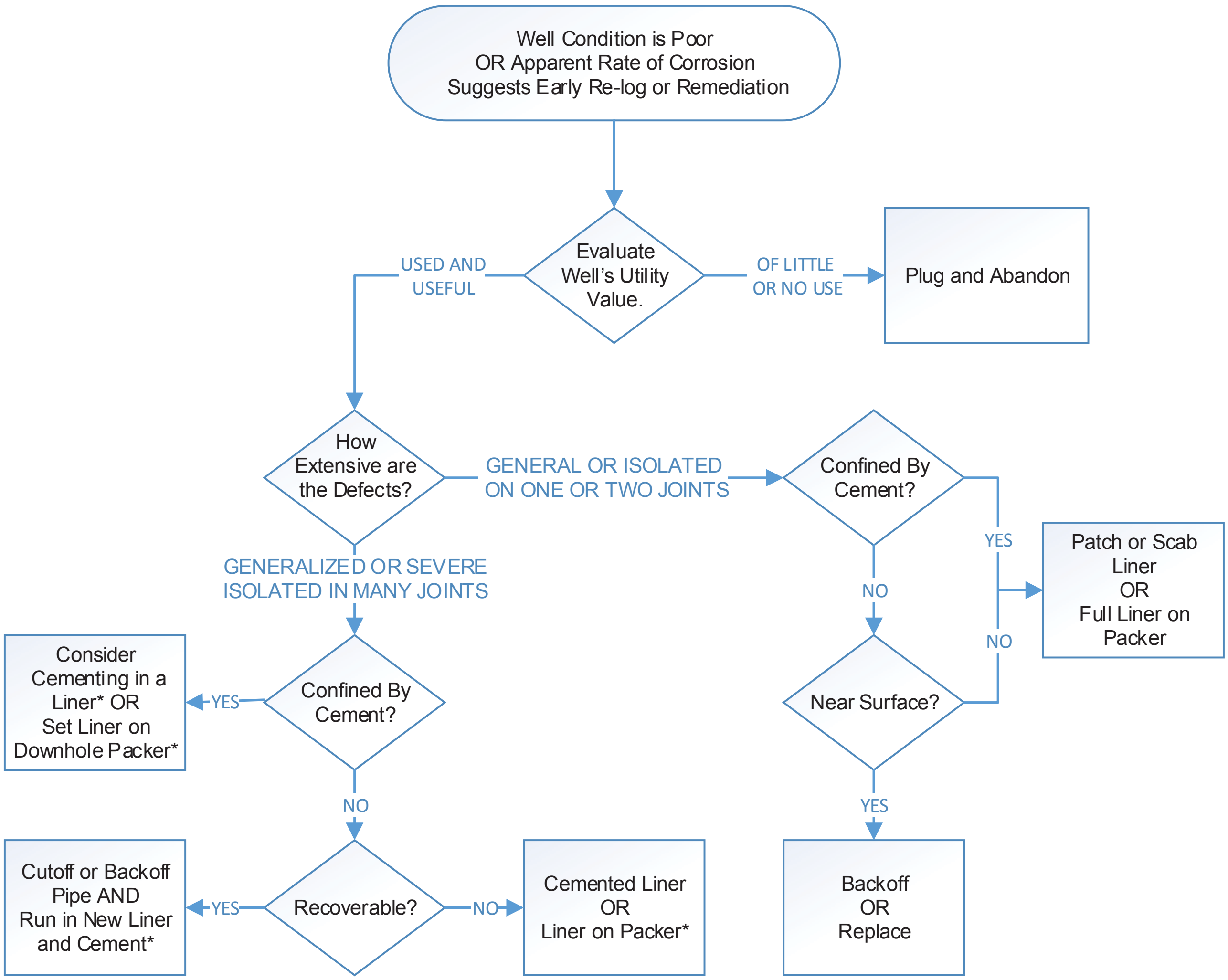
3. Hydrostatic testing program had established confidence in fairly high threshold for failure pressure of typical pipe sizes and pitting geometries.

   (1) Typical failure pressure of unconfirmed, corroded casing pipe, especially isolated pits, with at or in excess of API minimum for unaltered pipe.

   (2) Failure pressure of unconfirmed, corroded pipe exceeded calculated failure pressure based on NG-18 formula for line pipe.

4. Remediation or shorter-frequency re-log depends on approximate metal loss and on nature of defect patterns (geometry and location), 115% of the well's Maximum Allowable Operating Pressure (MAOP), and a complete review of the well's operating history. This history is in a variety of records on the GSAM shared drive for the well, and in Simplicity (Gas System Operations SCADA records).

Page 2 of 2



*If lining or tubing of the well will have a significant and adverse impact to well and field deliverability, consideration can be given to drilling additional or replacement wells with or without plugging of the well with corroded casing

Figure D-1: Remediation Decision Tree

Appendix E, Practice 1 - Design and Specifications for Construction of Natural Gas Storage Wells

Page 1 of 38

DESIGN AND SPECIFICATIONS FOR CONSTRUCTION OF NATURAL GAS STORAGE WELLS

Purpose: Provide requirements, specifications and procedures for the design and construction of natural gas storage wells.

What: This is to document the design and specifications for construction of natural gas storage wells.

Why: This document is to provide standard design and specifications for storage wells in each of the PG&E owned storage fields for ease of operation, maintenance, training, and troubleshooting.

When: This applies to new wells and reworks.

Who:

- Director of Reservoir Engineering (D-RE)
- Reservoir Engineers (RE)
- Reservoir Specialists (RS)

E.1 General

Appendix E (Practice 1) defines requirements for the design and construction of natural gas storage wells operated by PG&E. It applies to the drilling and completion of new wells, the remediation and reconditioning of existing wells (reworks), and the abandonment of wells.

E.2 Wellhead Equipment and Valves

Wellhead equipment shall comply with Practice 1A, Wellhead Equipment Design Standard. New and replacement wellhead equipment should conform to API 6A, Specification for Wellhead and Christmas Tree Equipment.

E.3 Well Casing

The design of well casing shall comply with Practice 1B, Tubular Design Standard.

E.4 Casing Cementing Procedures

Cementing of well casing shall comply with Practice 1C, Cementing Standard.

E.5 Completion and Stimulation

Completion and stimulation operations shall be designed and conducted to ensure that the integrity of the storage reservoir, caprock, well tubulars, casing cement, and wellhead equipment is preserved. In particular, loads generated during completion and stimulation operations should be compared to wellhead and tree pressure limits and to casing and tubing strengths to ensure that the minimum safety factors in Practice 1B are met.

The design and installation of completion tubing shall comply with Practice 1B, Tubular Design Standard.

Baseline cased hole logging should be performed on all wells as described in Appendix A, Well Logging Criteria for New Wells, Table A-2.

Fracture stimulation treatment requires special considerations and should follow API guidance documents API HF1, API HF2, and API HF3. Following fracture treatment, offset wells and the reservoir should be monitored for indications of a loss of well integrity.

E.6 Well Remediation (Reworks)

Wells suspected of having impaired mechanical integrity will be evaluated according to Appendix D, Remedial Options and Decision Tree. Depending on the degree of impairment, consideration should be given to isolating the well with kill weight brine and monitoring wellhead pressures and fluid levels until well remediation begins.

Existing well records, including casing inspection logs and mechanical integrity test data, should be reviewed when planning well remediation work. Well remediation planning should consider anticipated storage reservoir pressures prior to and during well remediation activities.

Prior to returning a reworked well to service, the well's integrity should be reassessed. Depending on the nature of the well work performed, casing inspection logging and/or pressure testing should be performed.

E.7 Well Closure (Plugging and Abandonment)

Plugging and abandonment of wells shall comply with Practice 1D, Well Abandonment Standard.

E.8 Environmental, Safety, and Health

API 1171 requires several design and construction safeguards that are met with this plan and the companion guidance documents:

1. Safeguards to the environment, safety, and health of workers and the public shall be incorporated into well design and well work activities.
2. Actions shall be taken to protect surface water and groundwater resources in the design, drilling and servicing of a well.

3. Worksite conditions shall be monitored during well construction and well work activities in order to protect the environment and the safety and health of workers and the public.
4. An emergency response plan shall be in effect as described in Section 10 of the API 1171. This is addressed in Section 16 of this plan.

Well work, construction, or any other work activity for PG&E includes preparation of an Environmental Release to Construction (ERTC) for review by PG&E's Environmental Field Specialist (EFS) prior to the work activity. This process is very similar to an environmental impact review as recommended for drilling operations in API 1171. The EFS will provide a formal approval, along with any required monitoring activities and/or preparation work required for the specific project approved to provide safeguards to the environment and compliance with local environmental regulations. Additionally, well work and construction is performed in alignment with PG&E's Safety and Health and Contractor Safety Programs.

API 49, 51R, 54, and 76 identify additional safeguards for storage well design and well work activities, as referenced in API 1171.

PG&E's Gas Emergency Response Plan (GERP) which is updated annually and includes a Well Control Tactical Considerations Plan, provides emergency response procedures during well design, construction and well work activities. A blowout contingency plan shall be in place that is PG&E specific as outlined in API 1171 Section 10.6.3.

E.9 Testing and Commissioning

New storage wells, new production casing installations, and wells in which the production casing is modified shall undergo pressure testing and baseline casing inspection logging to demonstrate mechanical integrity.

Production casing shall be pressure tested to 115% of maximum allowable operating pressure (MAOP) in accordance with Appendix Z, Well Integrity Testing Regime Process, and applicable regulatory requirements. New casing shall be tested prior to drilling out the shoe, and existing casing shall be tested with a plug set as close as practical to the top of the storage formation. On wells with tubing-packer completions, the tubing-casing annulus shall be pressure tested to meet regulatory requirements.

Loads generated during pressure testing should be compared to wellhead and tree pressure limits and to casing and tubing strengths to ensure that the minimum safety factors in Practice 1B are met.

Baseline casing inspection logging will be performed in accordance with Appendix S, Practice 15, Casing Inspection Logging and Data Assessments, and Appendix Z, Well Integrity Testing Regime Process.

E.10 Monitoring of Construction Activities

Development and replacement field activities that affect well design and construction should be evaluated prior to job execution and monitored during execution to verify and document that mechanical integrity of the well is maintained. All well activities should be supervised at the job site by competent personnel to ensure company procedures, regulatory and safety regulations, and any necessary geologic and engineering aspects of the well work are followed. The skills of such personnel and suitability for any equipment used should be documented.

Company procedures should be written clearly to allow competent personnel to follow the procedure consistently to achieve desired objectives. Current procedures shall be available and readily accessible to operations, maintenance, and storage personnel in either paper or electronic format. These procedures should outline monitoring activities. General procedures may be adapted for integrity monitoring activities. Training should be provided for any personnel (including contractors) designated to monitor storage wells during field activities which affect well design and construction.

API 1171 requires recordkeeping of the Monitoring of Construction Activities as outlined in E.11.

E.11 Recordkeeping

Well construction, completion, and wellwork records shall be maintained for the life of the storage facility. Well construction shall be documented in wellbore schematics and wellhead diagrams, as described in Appendix F and Appendix G, respectively.

Specific records to be maintained shall include, as applicable, the following items listed in Section 6.11.1 of API RP 1171:

- *6.2 Wellhead Equipment and Valves*

— Material and test records

— Design evaluations

— Emergency shut-down valve evaluation

— Inspection and repair records

— Wellhead Schematic

- *6.3 Well Casing*

— Material and test records

— Design evaluations

— Setting depths of all strings of casing

— Connection design evaluation

— Connection torque verification

- *6.4 Casing Cementing Practices*

— Blends, additives and volumes pumped

— Volume of cement circulated to surface

— pH of mix water and water temperature

— Pump and displacement rates and displacement times

— Pre-flush type and volume pumped

— Type of float and centralization equipment and location in string

— Theoretical and actual displacement volumes

— Detail of remedial cementing work performed

— Cement service company's field report and log of job

— Logged cement placement and any evaluation of quality of seal

- *6.5 Completion and Stimulation Considerations*

— Service company field reports and job logs

— Location and description of stimulation treatments

— Composition and volumes of any fluid used

— Cementing reports (as detailed in 6.4 Casing Cementing Practices)

— Type of equipment used and location in well

— Cased hole correlation logs

— Post treatment monitoring data and analysis

- *6.6 Well Remediation*

— Cementing reports (as detailed in 6.4 Casing Cementing Practices)

— Type of equipment used and location in well

— Well logs

— Work over and recompletion reports

- *6.7 Well Closure*

— Equipment removed from well

— Cementing reports (as detailed in 6.4 Casing Cementing Practices)

— Plugging records filed with local regulatory authorities

- *6.9 Testing and Commissioning*

— Mechanical integrity test data

— Pressure test data

— Type and amount of fluid in annulus of tubing packer completion

— Casing inspection logs

- *6.10 Monitoring of Construction Activities*

— Received equipment and material specifications

— Changes in well construction from original well design

— Rig and service company field tickets and job logs

— Mud records, mud log, driller’s logs, geolograph records, daily drilling or servicing reports

Appendix E, Practice 1A - Wellhead Equipment Design Standard

PRACTICE 1A - TABLE OF CONTENTS

1. SCOPE

1.1. Purpose

The purpose of the Wellhead Equipment Design Standard (WEDS) is to ensure that wellhead and associated equipment design performed by PG&E meets internal and regulatory requirements and does not pose a well control or safety risk.

The WEDS adheres to the following:

- PHMSA IFR – Pipeline Safety: Safety of Underground Natural Gas Storage Facilities
- State, Federal and other local jurisdictions regulations

1.2. Application

The WEDS is to be applied for:

- the design of new wells
- analysis of wells scheduled for remediation and reconditioning

- analysis of existing wells

The WEDS is to be utilized for both casing flow and tubing flow (tubing packer completions) wells.

1.3. Contents

The WEDS contains the design factors and considerations required to perform wellhead equipment design or design verification. Operating procedures produced separately to the WEDS detail the steps required to complete a wellhead equipment design.

1.4. Deviations from Design Standard

Wellhead equipment designs that do not meet the minimum requirements of the WEDS require approval from a PG&E Officer. Similarly, provisions containing the word ‘‘should’’, “may” or other non-mandatory language will be considered mandatory where denoted by a footnote. Depending on the degree of deviation, a risk assessment may be required.

Wellhead equipment designs that exceed the requirements of this standard are acceptable; however, the well designer should[2] evaluate the additional costs and benefits associated with such a design.

2. Wellhead Equipment and Valves

2.1. General

The wellhead acts as an interface between the casing and tubing strings in the wellbore and the surface facilities. The wellhead provides a suspending point for the casing and tubing strings running through the wellbore and also acts to contain the pressure inside the casing and tubing strings. The wellhead can be used for pressure monitoring for casings and annuli between different casing and tubing strings.

Newly installed wellhead equipment, including associated equipment (fittings, flanges, valves) should[i] conform to API 6A.

2.2. Wellhead Equipment Design

Newly installed wellhead equipment shall allow for full-diameter wellbore entry. A review of the well records shall[4] be conducted at the planning stage of a well maintenance. The goal of this review is to assess whether the level of wellbore access allowed by the existing wellhead is sufficient to conduct the planned operations.

---

[2] As per API RP 1171

Valves isolating the well from the pipeline system (including jurisdictional or regulated) and valves allowing for wellbore access shall[3] be part of the wellhead equipment.

All wellhead assembly ports should[3] be equipped with valves, blind flanges or similar equipment.

2.3. Pressure Rating

Wellhead equipment operating pressure ratings shall[3] exceed maximum anticipated operating pressure. Additionally, the following aspects should[3] be considered and evaluated as part of the well head equipment design (per API 1171 Section 6.2.3):

- Treating and stimulation pressures
- Flow rates
- Chemical composition of produced and stimulation fluids
- Anticipated solid production
- Anticipated increases in maximum operating pressure
- Intended flow path
- Anticipated need for tubular/annular pressure monitoring

2.4. Existing Equipment

Existing equipment is considered acceptable if it can contain the maximum operating pressure. Before any increase in operating pressure beyond the historical maximum, suitability of existing equipment shall[3] be evaluated.

2.5. Wellhead Emergency Shutdown Valves

Although automatic or remote-actuated emergency shut down valves (wellhead, side-gate, or subsurface) are usually not required on storage wells, the need for any type of emergency shut down valve shall[3] be evaluated considering the following (per API 1171 Section 6.2.5):

- Whether the well is an “active observation well” recognized by DOGGR, as defined by PRC §3008 (c), or is a “gas storage well” as defined by PRC §3180 (a)

[3] As per API RP 1171

- Distance from dwellings, buildings intended for human occupancy or well-defined outside areas where people assemble such as campgrounds, recreational areas or playgrounds
- Gas composition, total fluid flow and maximum flow potential
- Distance between wellheads, or between a wellhead and other facilities, and access for drilling and service rigs and emergency services
- Added risks created by installation and maintenance requirements of safety valves
- Risk to and from the well related to transport infrastructures (roadways, airports, etc...) and industrial facilities
- Alternative protection measures provided by barricades and railings, or other such devices
- Present and anticipated development of the surrounding area, topography and regional drainage systems and environmental considerations

Additional guidance on the design, installation and testing of subsurface safety valves is provided in API 14A and 14B.

3. General and Location Specific Wellhead Equipment Design

The wellhead assembly consists of casing head, tubing spool which includes casing valves, Christmas tree assembly which includes master gate valve, studded cross, and tubing valve. The typical components found on PG&E wells may include:

(a) Casing head:

- Casing head with two outlets
- Bull plug
- Nipple
- Ball valve
- API ring
- Casing slips and packing

(b) Tubing head:

- Tubing head with flanged outlets

- Double studded seal flange
- Flanged expanding gate valves
- Companion flanges
- Tubing hanger
- Gate valves
- API rings

(c) Christmas tree assembly:

- Master gate valve
- Single studded adapter
- Studded cross
- Flanged expanding gate valve
- Christmas tree cap/ wireline adaptor
- Companion flanges
- API rings
- Bull plug tapped ½"
- Nipple

4. Required Documentation

4.1. Well Work Records - Minimum Requirements

As per API RP 1171, records of well completion (as-built), well construction and well work activities shall[4] be maintained for the life of the facility. These records shall[4] include, as applicable and available, the items listed below.

[4] As per API RP 1171

- **Wellhead Equipment and Valves**
  - Material and test records.
  - Design evaluations.
  - Emergency shutdown valve evaluation.
  - Inspection and repair records.

4.2. Record Keeping

The wellhead equipment design documentation shall be stored in the PG&E well files for the life of the storage facility.

5. References

Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. API RP 1171, 2015

Specification for Wellhead and Christmas Tree Equipment. API SPEC 6A 19th Edition 2004

Appendix E, Practice 1B – Tubular Design Standard

PRACTICE 1B - TABLE OF CONTENTS

1. SCOPE

1.1. Purpose

The purpose of the Tubular Design Standard (TDS) is to ensure that casing and tubing design performed by PG&E meets internal and regulatory requirements and does not pose a well control or safety risk.

The TDS adheres to the following:

- PHMSA IFR – Pipeline Safety: Safety of Underground Natural Gas Storage Facilities
- State, Federal and other local jurisdictions regulations

1.2. Application

The TDS is to be applied for:

- the design of new wells
- analysis of wells scheduled for remediation and reconditioning
- analysis of existing wells

The TDS is to be utilized for both casing flow and tubing flow (tubing packer completions) wells.

1.3. Contents

The TDS contains the approved design factors and load cases required to perform casing and tubing design or design verification. Operating procedures produced separately to the TDS detail the steps required to complete a casing or tubing design.

The design documentation specified in Section 6.0 shall apply to all casing and tubing designs.

1.4. Deviations from Design Standard

Tubular designs that do not meet the minimum requirements of the TDS require approval from a PG&E Officer. Similarly, provisions containing the word ‘‘should’’, “may” or other non-mandatory language will be considered mandatory where denoted by a footnote. Depending on the degree of deviation, a risk assessment may be required. Depending on the degree of deviation, a risk assessment may be required.

Tubular designs that exceed the requirements of this standard are acceptable; however, the well designer should evaluate the additional costs and benefits associated with such a design.

2. Design Premise

2.1. Conductor Casing Design

The purpose of the conductor casing is to support unconsolidated surface deposits. The conductor size and grade should[5] be sufficient to accommodate the drilling of the surface hole and installing the surface casing.

2.2. Surface Casing Design

The purpose of the surface casing is to protect ground water and to ensure safe drilling operations until the next casing string is set. The surface casing shall be of sufficient size to accommodate the subsequent drilling and setting of casing strings. The weight and grade shall be sufficient to meet the load cases specified in section 4.

Surface casing shall be cemented into or through a competent bed and at a depth that will allow complete well shut-in in the event of a well control situation.

2.3. Intermediate Casing Design

Intermediate casing may be required on a well by well basis to provide protection against abnormal hole conditions such as cavings, lost circulation or abnormal pressure. The intermediate casing shall be of sufficient size to accommodate the subsequent drilling and setting of casing strings. The weight and grade shall be sufficient to meet the load cases specified in Section 4.

2.4. Production Casing Design

The production casing is for the purpose of isolating the storage formation/zone and providing a conduit between the storage zone and the surface. The production casing shall be of sufficient size to accommodate the production liner, production tubing and downhole safety valve (if installed) and to accommodate the desired withdrawal flow rate on casing flow wells. The weight and grade shall be sufficient to meet the load cases specified in section 4 and also be compatible with proposed fluid compositions.

The production casing setting depth is generally near the base of the cap rock shale above the storage zone, however, in certain circumstances the production casing setting depth may be at the total depth of the well.

---

[5] As per API RP 1171

Remedial inner casing strings installed inside existing production casing shall be designed as production casing.

2.5. Production Liner & Gravel Pack Design

The production liner, in conjunction with the gravel pack, is for the purpose of filtering the storage formation fines from entering the wellbore to minimize sand production.
Design Considerations:

- For open hole completion, wire-wrapped screen is normally used to allow maximum exposure to the formation
- Screen size is determined as follows:
    - From the core (or appropriate historical field data) having the smallest particle, determine the d50 (50%) particle size of the cumulative passing through sieve analysis
    - Use Saucier's method to determine the grave size (6 x d50)
    - The final design gravel sizes straddle the gravel size determined in above calculation
    - Use 75% the smallest gravel size for the screen opening.
- The length of the production liner depends on the formation thickness and should consist of the following from top to bottom:
    - Liner hanger
    - Gravel packing equipment
    - One joint of blank casing
    - Shear-out safety joint
    - One joint of blank casing
    - A slim pack pre-pack wire wrapped screen
    - The wire-wrapped screen length should be the difference of total depth of the hole and the production casing shoe, less 5' +/-.
    - O-ring seal sub
    - Gravel pack set shoe.

2.6. Production Tubing Design

The production tubing design will depend on whether the well is completed for casing flow or tubing flow.

In addition to the tubing design described in this standard a tubing-packer loading analysis shall be performed by the service company for all retrievable packer installations or stabbing of tubing into a liner hanger or permanent packer. The tubing packer loading analysis should consider the same load cases as the production tubing design.

Casing Flow

The production tubing serves as a means to lift produced water from the bottom of the well bore during withdrawal operation. The production tubing may also be used for gas flow during withdrawal and for gas injection.

The tubing size will depend on storage operations, reservoir performance, fluid dynamics and characteristics. The weight and grade shall be sufficient to meet the load cases specified in section 4.

For wells having downhole safety valves (DHSVs), the production tubing design shall consider the DHSV packer which is generally set at approximately 250’ below ground.

Tubing Flow

The production tubing serves as the conduit for gas injection and gas withdrawal. In tubing flow situations, the production packer is generally set within 100’ of the storage zone.

The tubing size should be designed to accommodate the desired withdrawal rate. The length of the tubing should be hung 10 to 15’ from bottom of the production liner. The weight and grade shall be sufficient to meet the load cases specified in section 4.

For wells having downhole safety valves (DHSVs), the DHSV is set at approximately 250’ below ground.

2.7. Connections

For surface casing and intermediate casing, API connections should generally be specified unless there is a compelling reason to use a non-API connection.

For production casing and tubing, the selected tubular connection shall be designed to maintain a gas seal during injection and withdrawal operations and during subsequent well work operations. Tubular design using non-API connections shall use published performance data supplied by the manufacturer. Triaxial design limit plots should be requested from the connection manufacturer. The ability to obtain crossovers, float equipment, and completion equipment should be considered when specifying non-API connections.

2.8. Tubular Installation

Storage, transportation, lifting and installation shall be in accordance with the manufacturer's recommendations and API RP 5C1.

Casing and tubing connection make up shall be in accordance with manufacturer specifications or API SPEC 5CT. Thread compound or lubricant shall be compatible with wellbore conditions and shall conform to manufacturer's recommendations or API RP 5A3.

3. Design Factors

3.1. Design and Safety Factors

The load (i.e., pressure, force or stress) calculated for the load cases in Section 4.0 shall be divided by the strength/rating of the affected tubular component to calculate a safety factor (SF).

SF = Strength Rating / Load

3.2. Tubular Strength Ratings

For the installation of new tubing or casing, tubular strength ratings shall be based on the latest edition of API Technical Report 5C3 (ISO10400). For non-API tubular connections, published manufacturer data shall be used.

For ongoing verification of mechanical integrity for existing wells, the API historical internal pressure rating (Barlow formula) and modified B31G burst formula may be used as described elsewhere in the PG&E Underground Storage Risk and Integrity Management Plan.

3.2.1. Burst

Uniaxial burst (internal pressure) design shall be based on the lowest of the following four internal pressure ratings shown in the latest edition of the API Technical Report 5C3 (ISO10400):

1. Pipe body internal yield
2. Connection internal yield
3. Connection pressure leak resistance
4. Pipe body ductile rupture

The well designer should be aware that the ratings for items 2, 3 and 4 above may be lower than the Pipe body internal yield (item 1), which is the burst rating most commonly shown in reference materials.

Pipe body internal yield ratings shall use API formulas which are based on 87.5% of nominal wall thickness (allowable pipe manufacturing tolerance), unless a caliper survey or ultrasonic inspection is used to measure actual wall thickness.

3.2.2. Collapse

API collapse strength ratings shall be derated for tension in accordance with API TR 5C3.

3.2.3. Axial

Axial analysis shall be based on the minimum yield strength of the casing/tubing grade.

3.2.4. Triaxial

Triaxial analysis shall be based on the minimum yield strength of the casing/tubing grade.

4. Load Analysis

Casing and tubing design shall consider all loads that are reasonably expected to occur during tubular installation, subsequent drilling and completion operations, gas storage operations, and wellwork (reworks, assessments, stimulations, abandonment) during the life of the well.

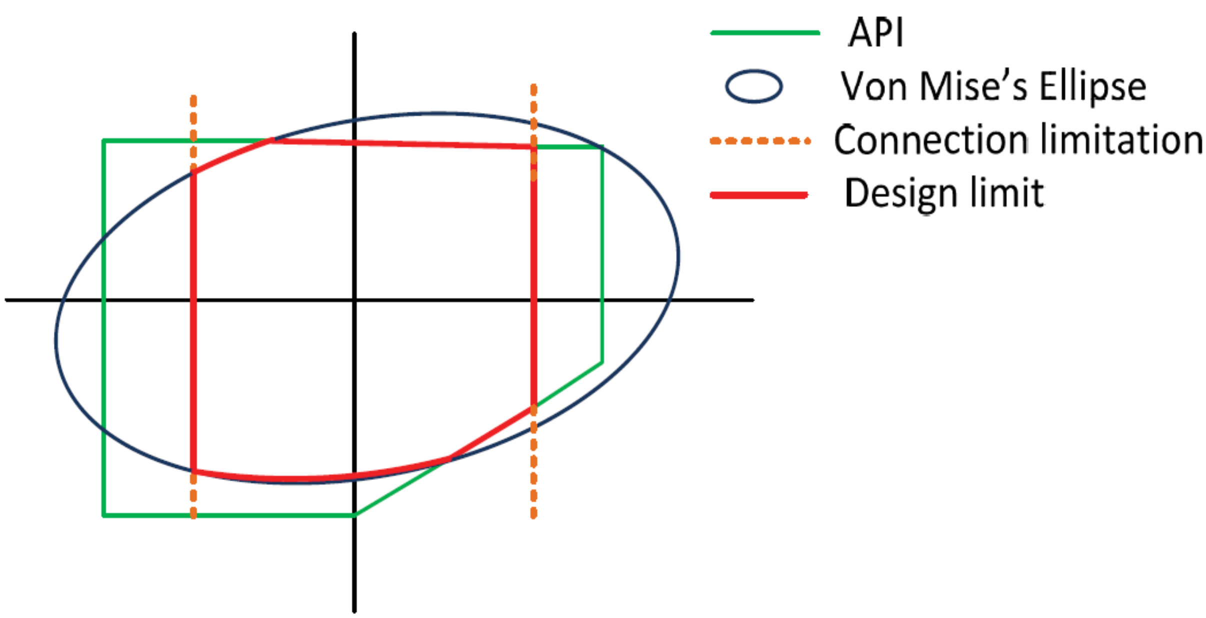
A tubular design analysis will be carried out for all new wells and wells scheduled for remediation and reconditioning. For existing wells, a sampling approach can be taken whereby, a single well design can be applied to multiple wells as long as the well construction satisfies a common set of design parameters.

4.1. Calculation Methodology

All wells should be analyzed using both uniaxial (burst, collapse and axial) and triaxial loading.

Triaxial loading shall use the Von Mise's methodology for combined pressure and axial loading. The Von Mise's triaxial load evaluation allows the casing design to be analyzed under a combination (more realistic) of loads. The design limit takes into account the API, Von Mise's and connection (coupling) design values and utilizes the minimum prescribed limit for each load – burst, collapse, tension & compression.

The design limits are shown in the graphical representation below where the X-axis is axial force (compression is <0, tension is >0) and the Y-axis is the effective differential pressure (collapse is <0, burst is >0). The governing design limit is defined by the solid red line; all load cases analyzed that are deemed to be acceptable will fall inside of the red line.



Software such as Landmark's *StressCheck* is available to perform triaxial analysis and is widely accepted across the oil and gas industry. For wells where thermal changes to the tubulars need to be taken into account, the software *WellCat,* also produced by Landmark, can be utilized.

4.2. Casing Load Cases

The following load cases shall be evaluated:

Burst Load Cases

Burst Load Cases	Surface Casing	Intermediate Casing	Production Casing (drilled through)	Production Casing
Drilling: Gas Kick – Displacement to Gas	X	X	X	N/A
Drilling: Pressure Test to Maximum Anticipated Surface Pressure (MASP)	X	X	X (115% of MAOP)	X (115% of MAOP)
Operations: Shallow Tubing Leak - Injection	N/A	N/A	X	X
Operations: Casing Flow Withdrawal	N/A	N/A	X	X

Burst Load Cases	Surface Casing	Intermediate Casing	Production Casing (drilled through)	Production Casing
Operations: Shallow Tubing Leak – Tubing Flow Withdrawal	N/A	N/A	X	X
Wellwork: Pressure Test – Block Testing	N/A	N/A	X	X
Wellwork: Gas kick – circulate out to kill well	N/A	N/A	X	X

Collapse Load Cases

Collapse Load Case	Surface Casing	Intermediate Casing	Production Casing/Liner (drilled through)	Production Casing/Liner
Installation: Cementing	X	X	X	X
Drilling: Lost Returns – with Mud Drop to balance pressure at loss zone	X	X	X	N/A
Operations: Full Evacuation	N/A	N/A	X	X

Axial Load Cases

Axial Load Case	Surface Casing	Intermediate Casing	Production Casing/Liner (drilled through)	Production Casing/Liner
Installation: Running in Hole	X	X	X	X
Installation: Overpull	X	X	X	X
Installation: Green Cement Pressure Test	X	X	X	X
Operations: Injection Cooling, Withdrawal Heating	N/A	N/A	X	X
Wellwork: Packer Release	N/A	N/A	X	X
Wellwork: Stimulation (if applicable)	N/A	N/A	X	X

4.3. Tubing Load Cases

The following load cases shall be evaluated:

Load Case	Description
Operations: Gas Injection	Burst
Operations: Gas Withdrawal	Burst
Operations: Shut-in	Burst
Operations: Shallow Tubing Leak – Gas Injection	Collapse
Wellwork: Bullhead Kill	Burst
Wellwork: Tubing Pressure Test	Burst
Wellwork: Casing (Annulus) Pressure Test	Collapse
Completion/Wellwork: Overpull - Packer Installation/release	Axial

5. Special considerations

5.1. Special Considerations Descriptions

Bending Loads

Axial loads (tension and compression) due to bending shall be considered during axial and triaxial design using the following formula:

Additional Tensile/Compressive Load due to Bending (lbs) = 218 x OD x DLS x A

OD = Outer pipe diameter (inches)

DLS = Dogleg Severity (°/100 ft)

A = Cross-sectional Area (sq. in)

Casing Wear / Heat-Checking

Casing wear and heat-checking can significantly reduce burst and collapse resistance.

Centering of the rig over the hole and use of a wellhead wear bushing shall be performed to avoid shallow casing wear.

Directional design and torque and drag analysis should be used to limit side loading pressures to ≤2,000 psi whenever possible to minimize casing wear during drilling. Non-rotating drill pipe protectors should be employed if side loading cannot be reduced with other means.

Consideration should be given to using the next larger wall thickness for casings that will be drilled through for extended periods.

For production casing that is drilled though for more than 14 days, consideration should be given to running an ultrasonic wall thickness log (e.g., USIT) or caliper survey to determine remaining wall thickness and calculate new strength ratings prior to placing the well on production. The results may dictate the need for a tieback or scab liner.

Corrosion

PG&E periodically runs casing inspection logs on their gas storage wells. The wall thickness results can be compared against the maximum allowable wall thickness loss (calculated from the tubular design analysis). The resulting analysis may require preventative measures be applied to ensure well integrity, such as: installing an inner string or casing patch, imposing operating limits, or modifying the annular fluid. Historical casing corrosion results should be utilized when designing a new well to allow sufficient allowance for wall loss during the life of the well.

The frequency of wall thickness monitoring must be evaluated using risk assessment.

Slotted Liners / Wire-wrapped Screens

The axial strength of slotted or perforated liners shall be derated based on the amount steel removed.

The blank portions of slotted liners and wire-wrapped screens shall be designed to meet the same burst and collapse loads as a blank cemented casing would be designed.

Landing Strings

Casing landing strings shall meet the axial load requirements of the upper most casing string section.

Rotating Casing or Liner

If casing or liner will be rotated during installation, the pipe body and connections shall be designed to withstand expected torsional and bending loads.

6. Required Documentation

6.1. Well Work Records - Minimum Requirements

As per API RP 1171, records of well completion (as-built), well construction and well work activities shall be maintained for the life of the facility. These records shall include, as applicable and available, the items listed below.

- **Well Casing**
    - Material and test records.
    - Design evaluations.

- Setting depths of all strings of casing.
- Connection design evaluation.
- Connection torque verification.

- **Completion and Stimulation Considerations**
  - Service company field reports and job logs.
  - Location and description of stimulation treatments.
  - Composition and volumes of any fluid used.
  - Cementing reports.
  - Type of equipment used and location in well.
  - Cased hole correlation logs.
  - Post-treatment monitoring data and analysis.
- **Well Remediation**
  - Cementing reports.
  - Type of equipment used and location in well.
  - Well logs.
  - Workover and recompletion reports.
- **Well Closure**
  - Equipment removed from well.
  - Cementing reports.
  - Plugging records filed with local regulatory authorities.
- **Testing and Commissioning**
  - Mechanical integrity test data.
  - Pressure test data.
  - Type and amount of fluid in annulus of tubing and packer completion.
  - Casing inspection logs.
- **Monitoring of Construction Activities**
  - Received equipment and material specifications.
  - Changes in well construction from original well design.

- Rig and service company field tickets and job logs.
- Daily drilling and servicing reports, geolograph records, and driller's log.
- Mud records.
- Wireline logs and mud logs.

6.2. Tubular Design Report - Minimum Requirements

A summary report should be provided for each tubular analysis, containing the following information:

- Casing Scheme (Size, Weight, Grade, Connection and depths for string section)
- List of Load Cases Considered
- Internal/External Loadings Used
- Assumptions/Uncertainties
- Minimum Safety Factors (Burst, Collapse, Axial) for each tubular string
- Weak Point Identification
- Kick Tolerance (if casing is drilled through)
- Limitations, including
  - Packer Fluid Density/Max. Allowable Mud Weight
  - Max. Allowable Dogleg Severity
  - Maximum allowable running speed
  - Pressure Testing
  - Max. Allowable Evacuation Depth
  - Corrosion/wear wall loss allowance
- For StressCheck analysis the following will be provided
  - StressCheck Detailed Report
  - Triaxial (Design Limits Plot)
  - Burst, Collapse, Axial loading charts (as appropriate)
- Tubing-Packer loading analysis

7. Record Keeping

The tubular design documentation shall be stored in the PG&E well files for the life of the storage facility.

8. References

Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used for Casing or Tubing; and Performance Properties Tables for Casing and Tubing. ANSI/API Technical Report 5C3, 2008 (ISO 10400:2007).

Well Integrity in Drilling and Well Operations. D-010 Rev 4 June 2013, NORSOK – Norwegian Petroleum Industry.

Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. API RP 1171, 2015

Specification for Casing and Tubing. API SPEC 5CT 9th Edition 2011

Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements. API RP 5A3 3rd Edition 2009

Recommended Practice for Care and Use of Casing and Tubing. API RP 5C1 18th Edition 1999

Appendix E, Practice 1C – Cementing Standard

PRACTICE 1C – TABLE OF CONTENTS

Underground Storage Risk and Integrity Management Plan

1. SCOPE

1.1. Purpose

Cement is an essential component for isolating the gas storage reservoir from hydraulic communication with other porous and permeable formations. This requires placement of competent cement within the annular space between the casing and formation to create a barrier/seal which prevents migration of fluids between the storage zone and any other reservoirs. The purpose of the Cementing Standard (CS) is to ensure that PG&E cementing practices meets internal and regulatory requirements and does not pose a well control or safety risk.

1.2. Application

The CS will be applied to cementing designs for new wells, planned remedial work on existing wells and for abandonment of gas storage completions.

1.3. Contents

The CS contains recommendations that conform to API Recommended Practice 1171 for all cementing that may be required during the life of a gas storage well.

1.4. Deviations from Design Standard

Cement designs that do not meet the minimum requirements of the Cement Standard require approval from a PG&E Officer. Similarly, provisions containing the word ''should'', "may" or other non-mandatory language will be considered mandatory where denoted by a footnote. Depending on the degree of deviation, a risk assessment may be required and approvals from State, Federal and other local jurisdictions.

Cement designs that exceed the requirements of this standard are acceptable; however, the well designer should evaluate the additional costs and benefits associated with such a design.

2. CEMENT QUALITY

As stated in API Recommended Practice 1171, cement should[6] meet quality standards in API 10A and ASTM C150/C150M or exceed the requirements set in these standards.

[6] As per API RP 1171

Underground Storage Risk and Integrity Management Plan

3. CEMENT IN WELL CONSTRUCTION AND REMEDIAL WORK

Cement slurries for the construction, remediation and plugging of gas storage wells should[7] be properly designed with cement quality and placement techniques to achieve wellbore and reservoir integrity. Cement properties, including density and water loss, should[7] be designed for the specific conditions of the wellbore to be cemented, considering the water source to be used to mix the cement.

3.1. Conductor Pipe

The conductor pipe, if set in a drilled wellbore, should[7] be cemented in the drilled hole with sufficient slurry volume to allow circulation to surface. If the conductor is driven, no cement is required.

3.2. Surface Casing

Cementing of the surface casing, if technically feasible, should[7] achieve the following: 1) include sufficient excess slurry volume to account for wellbore irregularities and/or formation losses, 2) circulation of slurry back to surface, 3) provide support for the wellhead and casing strings, and 4) isolate and protect groundwater from contamination with fluids from other sources. If cement does not circulate to surface, a top job may be performed to extend the top of cement to the surface. Surface casing should be cemented into or through a competent geologic formation and at a depth that will allow complete well shut-in without fracturing the formation immediately below the casing shoe.

3.3. Intermediate Casing

Any intermediate casing string run in a wellbore should[7] have cement slurry designed to allow cementing back to surface. Where this is not possible, the top of cement should[7] be to a point high enough within the surface casing to establish zonal isolation. The cement slurry should[7] be designed for the anticipated wellbore conditions.

3.4. Production Casing and Liners

Cementing of production casing or liners should[7] include a volume of cement designed to: 1) allow circulation of cement to the surface, or 2) allow circulation of cement to a point within the next casing string, or 3) establish zonal isolation of permeable zones. The cement slurry or combination of slurries and other fluids shall[7] be designed for hydrostatic weight control and strength requirements.

3.5. Cement Plugs

Cement plugs should[7] be designed with placement techniques to minimize the chance for contamination, since a diluted, non-uniform, or any other type of contaminated plug may not set properly. Small cement plug volumes are not recommended as they are more susceptible to

[7] As per API RP 1171

contamination. Cement plugs of any size should[8] be designed with slurry properties and placement techniques to provide isolation under the specific wellbore conditions in which they are placed.

3.6. Remedial Cementing

Remedial cement jobs required to achieve zonal isolation of the gas storage zone should[8] be designed and placed for specific wellbore conditions. The remedial cement design should[8] achieve isolation of the storage zone from all other sources of porosity and permeability.

4. CEMENT SLURRY DESIGN AND CONTROLS

A successful cement job requires a design that accounts for many factors including: 1) historical lessons of what has and has not worked in the past, 2) formation type, permeability, pressure and temperature, 3) prevention of contamination by formation fluids, 4) optimal compressive strength and 5) various additives to control fluid rheology (which affects displacement efficiency) and thickening times. All of this information should[8] be reviewed when designing a cement slurry.

4.1. Equivalent Circulating Density

API Recommended Practice 1171 states that the equivalent circulating density of the cement pumping operation shall[8] be designed such that the fracture gradient of the storage zone is not exceeded and such that lost circulation potential of any exposed zone is minimized. This may require alternative placement methods and/or alternative cement blends. Note that cement density shall also be designed to prevent entry of any formation fluids during the cementing process, including the cement thickening process, for production casing and/or liners.

4.2. Excess Slurry Volume

When the cement program calls for circulating cement to surface, excess slurry volume to account for wellbore irregularities and/or losses to the formation may be required. If available, an open-hole caliper log is very useful for determining casing-borehole annular volumes. Past practices, including cement densities used, excess volumes used, and cement top verification by logging should be reviewed and incorporated into the cement design.

4.3. Laboratory Testing

Cement slurry designs and requirements for thickening time and compressive strength may[8] be verified with laboratory testing, considering the properties of the mix water and other cement additives to be used under the specific wellbore conditions.

---

[8] As per API RP 1171

4.4. Mix Water

Sources of mix water may[9] be tested for PH and temperature prior to cement mixing to ensure adequacy. Mix water needs to come from a reliable, consistent source with sufficient deliverability to meet the planned cement pumping schedule. Mix water needs to be within the specifications used for the laboratory testing. A geochemical analysis may be conducted on any water source used during cementing where such properties are unknown or questionable.

4.5. Slurry Samples

Slurry surface samples should[9] be obtained after mixing and prior to pumping down hole and held for further analysis. If multiple slurries are to be used, samples should be taken from each slurry type. If possible, multiple samples may be taken throughout the cement mixing process. Cement density may be measured throughout the mixing process as an additional quality control on proper cement mixing.

4.6. Wait on Cement Time

Rig operations following a cement job should[9] allow for sufficient cement cure time to develop target compressive strengths prior to resuming subsequent well activities. Required cure time should[9] be provided by the cementing company and/or laboratory results.

5. CEMENT PUMPING DESIGN

Isolating the gas storage reservoir from communication with other porous and permeable formations requires the proper placement of the cement slurry so as to provide good cement bonding with both the casing and the formation.

5.1. Fluid Conditioning

Prior to cementing a casing string, fluid in the wellbore should[9] be conditioned to improve fluid mobility, which will improve displacement by the cement slurry. Such displacement is needed for good cement bonding with the casing and the formation. Note: API Recommended Practice 1171 references API 65-2 for guidance on conditioning of fluid within the wellbore.

5.2. Spacers and Pre-flushes

Spacers and pre-flushes should[9] be used to help remove any mud cake that may exist and also isolate potential cement contamination due to dissimilar fluids. Mechanical means, such as scratchers, may also be used to remove mud cake. Note: API Recommended Practice 1171 states that spacers and pre-flushes are often weighted to prevent fluid entry during the pre-cementing hole conditioning process.

---

[9] As per API RP 1171

5.3. Casing Centralization

Casing centralization should[10] be used to prevent cement channeling, especially in and near zones where good cement bonding is critical, which may include areas with high wellbore inclination angles and/or highly permeable geologic formations – these factors should[10] also be considered. Note: API Recommended Practice 1171 states that casing centralization aids in the removal of drilling fluids behind the pipe during the cement slurry pumping process and thereby improves the uniform flow of cement up the annulus. API 10D-2, API 10TR4, and cementing service company technical experts can provide additional guidance and recommendations for proper casing centralization.

5.4. External Casing Packers

External casing packers and/or other mechanical barriers may[10] be used in zones where isolation through cementing practices alone has a lower than acceptable probability of success.

5.5. Guide Shoe and Float Collar

A guide shoe shouldi[10] be used on the first joint of the production casing to avoid issues such as wellbore ledges, sidewall caving and damage to the bottom of the casing while running in the well. A float may be added to the shoe to provide an additional barrier to backflow of the cement. A float collar should[10] be used one or more joints above the guide (or float) shoe to prevent cement from back flowing and to prevent contaminated cement from reaching the shoe. The float valve(s) should[10] be checked prior to full pressure release at the surface. Competent, uncontaminated cement shall[10] be placed around the casing shoe and around the circumference of the casing.

5.6. Wiper Plugs

A wiper plug should[10] be used during the cementing of the production string to help control displacement volumes and reduce the potential for cement contamination. Casing strings normally use a two-plug wiper system: one plug is run before the cement is pumped and the second plug is run after the cement is pumped. Proper plug inspection and loading is essential as the pre-cement plug is designed to rupture to allow the cement to pass through, and the post cement plug is not designed to rupture. Liners often use only one plug, depending on liner design.

5.7. Pipe Movement

Pipe movement (when feasible, including rotation and/or reciprocation) during hole conditioning and pumping of cement should[10] be used to eliminate or reduce the possibility of cement channeling. The movement of pipe should[10] stop once the cement is in place and while waiting on development of the cement's compressive strength. If scratchers are used, pipe movement can assist in mud cake removal during pipe movement.

[10] As per API RP 1171

5.8. Pumping and Mixing Equipment

Pumping and mixing equipment should[11] be rated appropriately for anticipated pressures and rates required for the job. Such equipment may be tested on site to the appropriate pressure prior to job start up. Cementing equipment should[11] be capable of controlling slurry density and providing a continuous pumping operation at designed rates and pressures. In order to address possible failure of pumping equipment, back-up equipment should[11] be available.

6. CEMENT EVALUATION AND LOCATION

Evaluation of the location and bonding quality of casing cement is essential in determining if a competent seal exists to confine storage gas below the cap rock and prevent migration out of zone. The location and quality of such bond or seal shall[11] be evaluated to ensure adequate formation and pipe bonding has been achieved to prevent migration of gas and fluids between zones. Cement bonding across the caprock of the storage zone is important.

Evaluation methods include: 1) a temperature log run in the first 12 to 24 hours after cementing to determine the location of the cement top and 2) both conventional bond logs and radial cement bond logs to determine that adequate bonding exists across the cap rock and help identify any cement channeling that can impair zonal isolation. The evaluation method used should[11] be run after the cement cure time required for the cement to reach sufficient compressive strength for accurate log measurement. The cement placement and bond quality evaluation shall[11] be conducted with a method that can demonstrate the sealing potential of the cement.

The well's annuli after cementing should[11] be observed to ensure that no annular flow exists.

API Recommended Practice 1171 cites API 10TR1 which provides principles and practices regarding the evaluation of primary cementation of casing strings in oil and gas wells and suggests a mechanical integrity test of each casing string should[11] be completed prior to drilling out or perforating.

7. RECORDKEEPING

As per API 1171, Section 6.11, records of well completion (as-built), well construction and well work activities shall[11] be maintained for the life of the facility. These records shall[11] include, as applicable and available, the items listed below for cementing practices:

- Cement blends, additives used, and volumes pumped
- Volumes of cement circulated to surface
- pH of mix water and water temperature
- Pump and displacement rates and displacement times

[11] As per API RP 1171

- Theoretical and actual displacement volumes
- Preflush type and volume pumped
- Type of float(s) and centralization equipment used and its location in the casing string
- Details of any remedial cementing work performed, including cementing reports, type of equipment used and its location in the well, rig and/or recompletion reports
- Cement service company's field report and job log
- Logged cement placement and any evaluation of the quality of the cement seal
- Received equipment and material specifications
- Changes in well construction from original well design
- Rig and service company field tickets and job logs
- Daily rig and servicing reports

It is also recommended that the cement density and yield be documented in the cementing records.

Underground Storage Risk and Integrity Management Plan

Appendix E, Practice 1D – Well Abandonment Standard

PRACTICE 1D – TABLE OF CONTENTS

1. Scope

1.1. Purpose

The purpose of the Well Abandonment Standard (WAS) is to ensure that well plugging and abandonment performed by PG&E meets internal and regulatory requirements and does not pose an environmental or safety risk.

The WAS adheres to the following:

- PHMSA IFR – Pipeline Safety: Safety of Underground Natural Gas Storage Facilities
- State, Federal and other local jurisdictions regulations

1.2. Application

The well abandonment standard is to be applied for:

- Consideration in the design of new wells

- Consideration of wells scheduled for remediation and reconditioning
- Wells scheduled for permanent abandonment

1.3. Contents

The well abandonment standard contains general guidance required to perform well abandonments. Operating procedures produced separately to the well abandonment standard detail the steps required to complete a well abandonment.

1.4. Deviations from Design Standard

Well abandonments that do not meet the minimum requirements of the well abandonment standard require approval from a PG&E Officer. Similarly, provisions containing the word ''should'', "may" or other non-mandatory language will be considered mandatory where denoted by a footnote. Depending on the degree of deviation, a risk assessment may be required and approvals from State, Federal and other local jurisdictions.

Abandonment designs that exceed the requirements of this standard are acceptable; however, the abandonment engineer should evaluate the additional costs and benefits associated with such a design.

2. General

A well has the potential to become a conduit for fluid flow between penetrated hydrocarbon bearing zones, freshwater aquifers and the surface. Properly plugging a well prevents such fluid migration, providing long-term isolation. The well abandonment design shall[12] provide for long term isolation of the storage zone in order to prevent fluid flow between the storage zone and any other penetrated zone and the surface.

At any depth where an isolation barrier is required, multiple casing strings may be present. The condition of casing and cement across these zones shall be determined in order for complete isolation to be achieved. This may mean, but is not limited to, analysis of cement bond logging, volumetric calculations and/or remedial cement operations.

API Bulletin E3 should be referred to for best practices and procedures for the detailed design and execution of the abandonment.

For compliance with State regulations, the Division of Oil, Gas and Geothermal Resources (DOGGR) regulations found in California Code of Regulations, Title 14, Div. 2, Chapter 4-1, Article 3 should be consulted.

[12] As per API RP 1171

3. Storage Zone Isolation

Effective isolation will be achieved by the equivalence of reinstating the cap rock. This includes isolation both inside and outside each casing string as required to prevent migration of fluids.

3.1. Plugs

Cement and/or mechanical plugs shall[13] be used to isolate the storage zones from fluid migration. For any design, the long-term viability should[13] be considered such that the required isolation is maintained. Hydrostatic pressure alone, shall[13] not be acceptable.

The quality of the cement used should meet or exceed requirements specified in API 10A and ASTM C150/C150M and should not use volume-extending additives.

Any cement plugs used for isolation should be of adequate length necessary to achieve long term isolation. Cement viability is considered in the U.S. Bureau of Safety and Environmental Enforcement (BSEE) Report RLS0116 which is referenced in API 1171.

To ensure the integrity of a cement plug, before the plug is placed, the well should[13] be static and remain so as the plug sets.

3.2. Ground Water Protection

The depth determined to be source of groundwater (Base of Fresh Water – BFW) shall also be protected to prevent contamination. The condition of the well's casing and cement across such zone shall be determined. The abandonment design shall include provisions to prevent communication between BFW and any other zone during and after the well is plugged. Remedial cement work may be required to isolate fresh water formations behind uncemented casing.

3.3. Hydrocarbon Bearing Zones

Hydrocarbon bearing zones (in addition to the storage zone) which were penetrated by any well to be abandoned shall be identified and the well's casing and cement across such zones shall be determined. The abandonment design shall include provisions to prevent communication between any of such zones during and after the well is plugged. Remedial cement work may be required to these zones behind uncemented casing.

3.4. Limited Wellbore Access

There may be several incidences where placement of plugs across the storage zone or other critical zones is limited due to wellbore conditions. The condition of the well to be abandoned should[14] be

[13] As per API RP 1171

[14] As per API RP 1171

assessed prior to well abandonment design. Special provisions may be needed to establish conditions for long term plug sealing reliability.

3.5. Verification of Casing-Borehole Seals

The location and presence of any cement plug shall[14] be verified once sufficient compressive strength has been reached, and any deviation which will endanger the efficacy of the isolation shall be rectified. The casing-borehole cement sealing the storage zone shall[14] be verified to achieve annular isolation and prevent communication.

4. Abandoned Well Maintenance

A surface plug and cap shall[14] be installed on any abandoned well. The cap shall[14] be marked with a form of identification such as the API number of the well and should be at least as thick as the thickest outer casing (be it conductor or surface casing).

Should a leak become evident, the implication may be that sufficient isolation has not been maintained and the appropriate repair shall[14] be facilitated.

5. Recordkeeping

As per API 1171 Section 6.11, records of well completion (as-built), well construction and well work activities shall[14] be maintained for the life of the facility. These records shall[14] include, as applicable and available, the items listed below for well abandonment:

- Equipment removed from the well
- Cementing reports
- Plugging records filed with local regulatory authorities
- Rig and service company field tickets and job logs

6. References

Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. API RP 1171, 2015

Environmental Guidance Document: Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations. API Bulletin E3 1st Edition 1993 (Reaffirmed 2000)

California Code of Regulations, Title 14, Div. 2, Chapter 4-1, Article 3, 2017

[1] As per API RP 1171

Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics

Page 1 of 2

CREATING AND UPDATING STORAGE WELLBORE SCHEMATICS

Purpose: Provide standards and procedures for creating and updating storage wellbore schematics.

What: The wellbore schematic provides a graphical representation of the wellbore, downhole equipment and tubulars, dimensions and installed depths, and anomalies detected from Vertilog, GR/N and T/N in each storage well for active wells only. Note: the official document of record of the data reflected on the wellbore schematic is well asset database.

Why: The document is to ensure that the wellbore schematics are updated to reflect the current physical configuration of the storage wells.

When: Create wellhead diagram and update for any changes of wellbore, downhole equipment and tubular after rework operation, and anomalies detected from casing integrity surveys (Vertilog, GR/N and T/N).

Who:

- Reservoir Engineering (RE) creates wellbore schematics for active wells only
- RE reviews wellbore schematics for completeness
- RE updates wellbore schematics

Procedure:

1. RE create and document existing wellbore configurations including, at a minimum, the following:
   a PG&E named as well owner
   b Lease name
   c Well location: S; T; R and GPS
   d Well name/number
   e API number (12-digit)
   f KB measurement or Reference Elevation
   g Base of groundwater with <3,000 ppm of dissolved solids content (shown as BFW)
   h Base of groundwater with <10,000 ppm of dissolved solids content (shown as USDW)

i Spud date

j Hole size diameter

k Completion date

l Date of last rework

m Sizes, weights, grades for:

- (1) Conductor dimension and depth
- (2) Surface casing dimension and depth

n Sizes, weights, grades, and connection types for:

- (1) Production casing dimension and depth
- (2) Tubing dimension and depth

o Cement fill behind casings including

- (1) Top and bottom of cemented interval
- (2) Method of determination (ie CBL & year run)

p All information used to calculation the cement slurry (e.g. volume, density, yield), including cement type and additives

q MD and TVD for all measurements

r Equipment details where installed:

- (1) DHSV: Make/model, dimension and depth
- (2) Casing patch dimension and depth
- (3) Packer element: Make/model and depth

s Production liner hanger, liner dimension and depth

t Stage collar depth

u Depth of casing shoes, stubs, or liner tops

v Known anomaly depths that influence flow in the well or may compromise mechanical integrity of the well

w Depth of perforated intervals, water shutoff perforations, cement port, cavity shot, cut, patch, casing damage

x Top of junk or fish left in well

y Cement plug detail

- (1) Date emplaced
- (2) Top and bottom depths
- (3) Method of determination

(4) Type and density of any fluid between plugs

z Depths and names of formation(s), zone(s), and geologic markers penetrated by well, including the top and bottom of the gas storage zone(s) and top and bottom of the confining strata

aa Footnote all measurements reference to KB

bb All items noted above for previously drilled or sidetracked wellbores

cc PG&E defined wellhead type. Note: Wellhead and wellhead valve assembly equipment by model and pressure rating are summarized on a general wellhead sheet by wellhead type.

2. RE updates wellbore schematics for any changes of downhole equipment and tubular after well rework operation and anomalies detected from casing integrity surveys

3. RE reviews for completeness

4. RE submits to GSBD G:\RSRVRENG\GSAM Wellbore Schematic and Info Sheets

Underground Storage Risk and Integrity Management Plan

Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams

CREATING AND UPDATING STORAGE WELLHEAD DIAGRAMS

Purpose: Provide standards and procedures for creating and updating storage wellhead diagrams.

What: The wellhead schematic provides a graphical representation of wellhead components including dimensions and pressure rating using API Standards. Note: the official document of record of the data reflected on the wellhead schematic is the well asset database.

Why: The document is to ensure that the wellhead component dimensions and pressure rating reflect the current physical configuration of the storage wellhead.

When: Create wellhead diagram and update for any changes of components, as needed, or after rework operation.

Who:

- Wellhead vendor creates wellhead diagram in digital format for active wells only
- RE reviews wellhead diagram generated by vendor for completeness
- RE updates wellhead diagram for any changes of components or as needed
- Vendor updates wellhead diagram in digit format as needed based on RE review
- RE reviews updated wellhead diagram and classifies the wellhead by category type; RE shall define a new category type as needed and update the wellhead detail sheet.

Procedure

1. RE document/verify component dimensions and pressure rating of wellhead diagram, or mark up an existing wellhead diagram as needed, including:
   a Type or make of wellhead
   b Casing head
   c Casing double studded flange
   d Tubing head
   e Tubing hanger
   f Seals
   g Test ports
   h Hydraulic control line ports

- i Surface casing valve
- j Casing wing valves
- k Tubing wing valves
- l Master Gate
- m Cross
- n Bonet
- o Date of last service and service performed

2. RE provides the above to DD
3. DD updates wellhead diagram
4. RE reviews for completeness
5. RE submits to GSBD

Underground Storage Risk and Integrity Management Plan

Appendix H, Practice 4 - Sand Inspection

Page 1 of 3

SAND INSPECTION

Purpose: Provide standards and procedures for sand inspections.

What: Sand inspections are used to monitor wells for the presence of sand and to determine what action is to be taken when sand is found.

Why: When gas wells produce gas at high velocities in the tubing or casing, any sand that is picked up in the flow stream becomes a potentially destructive element. Sand that is blasted against the piping, valves, chokes, or other parts of the system can destroy equipment in a very short time. Further the presence of sand is an indicator of a potential failure of the wells gravel pack and screen liner to prevent sand production.

When: Twice during the winter withdrawal period under a standard clearance: typically once in January and once in March. Note: If the winter withdrawal period is much shorter than usual, then the sand inspection may only be conducted once during this period. Reservoir Engineering should document reason for single sand inspection on form.

Who: Reservoir Engineering(RE) coordinates with Planning and GPOM to schedule testing and coordinates required clearances. RE communicates results to GPOM, Planning, and Corrosion.

Procedure:

1. Reservoir Engineering notifies Corrosion Department of planned testing schedule as to provide an opportunity to conduct internal visual inspection, solid sampling, or other corrosion testing during the sand inspection.

2. Reservoir Engineering personnel inspect the sand residue, if any, found in the sand traps and records the amount of sand on inspection form based on sand ratings and description shown below in Table H-1.

3. Reservoir Engineer shall review sand inspection ratings and Reservoir Engineering will provide an electronic copy of the sand inspection results to the Corrosion Department.

4. Reservoir Engineer will determine whether to downgrade the well's performance utilizing Table H-2 below according to the sand ratings and review results with supervisor. Additionally, Reservoir Engineer will consult Figure H-1 Tree Diagram for additional mitigation steps to consider.

Underground Storage Risk and Integrity Management Plan

5. Reservoir Engineer will update the maximum well flow rates table and gas storage database.

6. Reservoir Engineering will communicate rate change to UGS District Operations, Station Services, and Gas System Planning.

Table H-1. Sand Inspection Rating

Rating	Sand Description
0 - No Sand	* - Formation Sand
1 - Slight Trace	** - Gravel Pack Sand
2 - Trace i.e.: Up To ¼ Teaspoon	*** - Both
3 - Measurable Amount i.e.: Up To 1 Tablespoon	
4 - Significant Amount i.e.: Up To 1 Cup	
5 - Critical Amount i.e.: More Than 1 Cup	

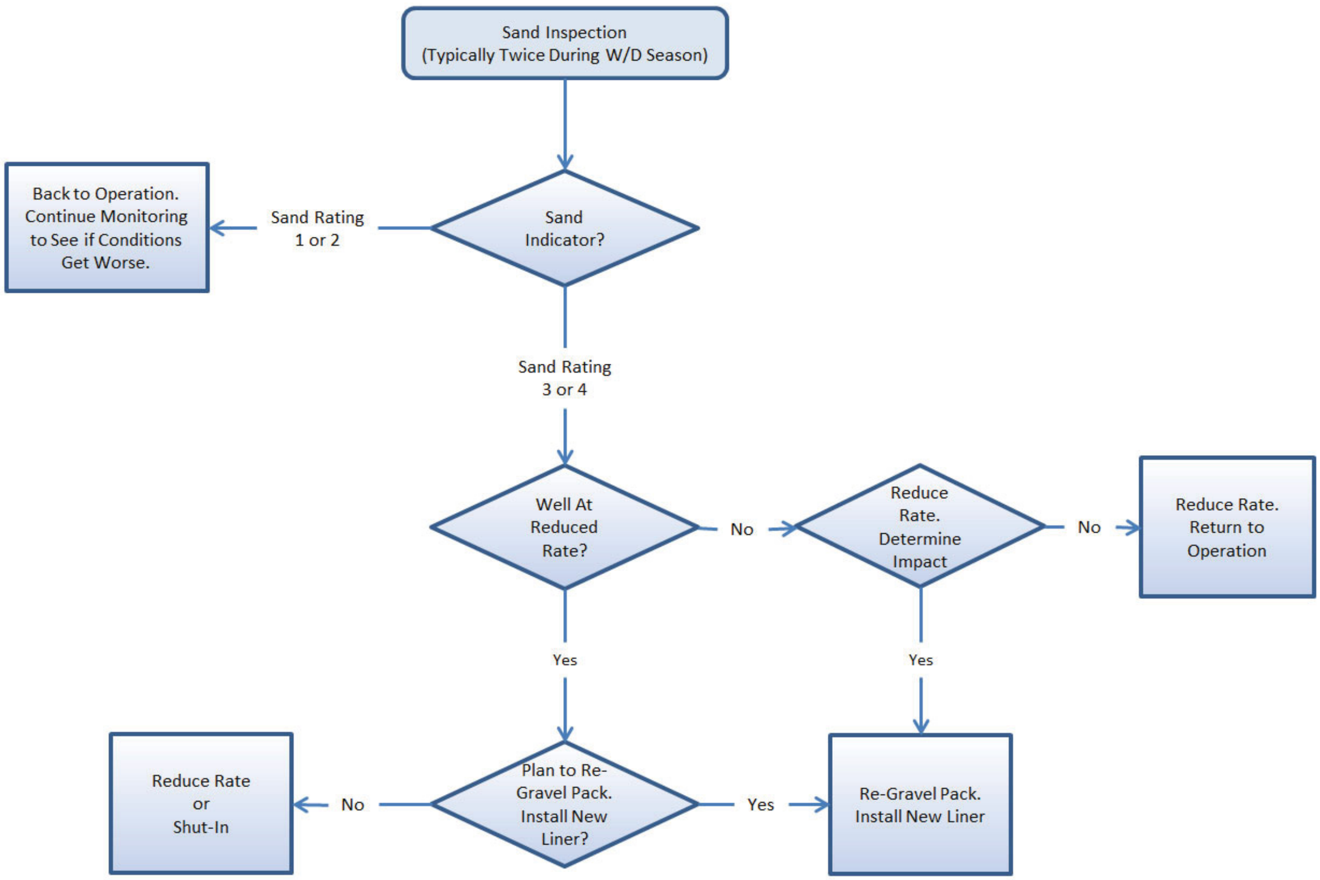
Table H-2. Sand Inspection Rating and Recommended Action

Rating	Recommended Action *
0 - No Sand	No downgrade
1 - Slight Trace	Monitor
2 - Trace i.e.: Up To ¼ Teaspoon	Monitor
3 - Measurable Amount i.e.: Up To 1 Tablespoon	Downgrade by 25%
4 - Significant Amount i.e.: Up To 1 Cup	Downgrade by 50%
5 - Critical Amount i.e.: More Than 1 Cup	Shut-In and Rework

* If the recommendation is not utilized an expectation should be prepared supporting variance.

Underground Storage Risk and Integrity Management Plan

Figure H-1. Sand Inspection Decision Tree



Appendix I, Practice 5 - Uphole Safety Valve (UHSV) Leak-by Test Procedures

Purpose: Provide standards and procedures for the testing of uphole safety valves.

What: "Uphole" safety valves (UHSV) or emergency shutdown valves (ESD) are installed on the transmission piping to isolate the transmission pipeline from abnormal low pressure downstream of the valve, including loss of containment of a storage well or the piping systems. UHSV are typically installed near the connection of the transmission piping and storage wellhead. This practice uses API Recommended Practice 14B Sixth Edition, September 2015 as guidance in developing the test procedures.

Procedure: See detailed UHSV testing procedures and data collection forms issued by Reservoir Engineering. The following table lists these documents for reference. The most current editions must be obtained from GSAM Reservoir Engineering. Current procedures reside in this IMP as Appendices I1 through I4.

Table I-1, Uphole Safety Valve Guidance Documents

File Name	Appendix	Title / Notes
McDonald Island - Operating Procedures - Uphole Safety Valve (UHSV) Annual Leak Test - Drawing Number 0800662 4/14/16 McDonald Island Uphole Safety Valve (UHSV) Test 4-14-2016.doc	I.1	
McDonald Island - Operating Procedures - Non-Platform Uphole Safety Valve (UHSV) Annual Leak Test - Drawing Number 0800662 4/14/16 McDonald Island Non-Platform Uphole Safety Valve (UHSV) Test 4-14-2016.doc	I.2	
Pleasant Creek Station - Operating Procedures Uphole Safety Valve (UHSV) Annual Leak 10/20/16 Pleasant Creek Uphole Safety Valve (UHSV) Test 10-20-2016.docx	I.3	
Los Medanos Station - Operating Procedures Uphole Safety Valve (UHSV) Annual Leak Test– (Drawing Number 0800608) 10/20/16 Los Medanos Uphole Safety Valve (UHSV) Test 9-26-2017.docx	I.4	

1. McDonald Island - Operating Procedures - Uphole Safety Valve (UHSV) Annual Leak Test - Drawing Number 0800662 4/14/16

1.1. Revisions

APPROVED BY		REV	DATE	DESCRIPTION	GM	DWN	CHKD	SUPV	APVD
LDK7	AAR3	0	3/17/2016	Issued for use as 4/14/16 edition	31103200	TFM0	A3BZ/BKZ1		G1CC/PXT6

1.2. Introduction

This procedure describes an annual test for platform wells in service (i.e., fully pressurized) at the Turner Cut and Whisky Slough Stations

This procedure applies to all Gas personnel whose work includes field testing valves.

SAFETY

Working outdoors on Gas equipment may result in exposure to environmental hazards, including heat, cold, and inclement weather.

Exposure and reaction to stings or bites from bees, ticks, snakes, and other wildlife also may occur when implementing this procedure.

Slips, trips, and falls and associated cuts, bruises, sprains, and worse can occur when walking on steep, unstable, uneven, slippery, or wet surfaces.

To minimize disturbance, a buffer of 15-30 feet is required if nesting birds are discovered.

1.3. Testing Procedure

1. **BEFORE YOU START**

    a. Schedule the job with Gas Operations.

    b. If necessary, request proper clearance to remove well from service.

c. Gather all appropriate personal protective equipment (PPE) per the Gas Operations Matrix.

d. Gather the following:

- Calibrated gauges
- Calibrated volume measurement and appropriate sized and pressure rated hose
- Job Safety Site Analysis (JSSA)
- McDonald Island UHSV Test Form

2. UHSV LEAK TEST

a. **CHECK** with Operations and inform the operator of the testing (about 4 hours).

b. **CLOSE** the following:

i. Master Gate V-13

ii. Casing Wing Valve V-12

iii. Casing Header Block Valve V-2

iv. Tubing Header Block Valve V-1

c. **CHECK OPEN** Cross Over Valve V-9.

d. **OPEN** the following:

i. Tubing Control Valve FVT in control room

ii. Casing Control Valve FVC in control room

iii. Blow Down Valve V-18

1. ENSURE line is bled to zero PSIG.

2. CLOSE the valve.

e. **INSTALL** a calibrated pressure gauge on the lines at the tree to check for ZERO pressure and location for test reads.

f. **CLOSE** the following:

   i. Tubing Riser Valve V-7

   ii. Casing Riser Valve V-8

   iii. Methanol main supply for well run

g. **START** the test by opening Master Gate Valve V-13 and Casing Wing Valve V-12.

h. Use the McDonald Island UHSV Test Form to **RECORD** the pressure buildup on tubing and casing well runs:

   i. In 15 minutes.

   ii. 1 hour later to completed test.

i. After test is completed:

   i. **CHECK** Blow Down Valve V-18 is CLOSED.

   ii. **OPEN** Tubing Riser Valve V-7, Casing Riser Valve V-8, and methanol main supply for the well run.

j. Slowly **OPEN** Tubing Header Block Valve V-1 to fully re-pressurize tubing well runs.

k. Slowly **OPEN** Casing Header Block Valve V-2 to fully re-pressurize casing.

l. **CLOSE** the tubing control valve (VFT) and the casing control valve (VFC) in the control room.

m. **RESET** the well.

n. Confirm the well returns to NORMAL.

3. END OF TEST

a. **NOTIFY** Operations on completion of testing.

b. Immediately **REPORT** any abnormal issues to the Operations supervisor.

c. Ensure the test form is filled out completely, including the tester's LAN ID, DATE, and TIME.

d. **SCAN AND SECURELY FILE** a local hard copy of each data form.

e. **EMAIL** scanned copies to the Operations supervisor and Reservoir Engineering (gasopsstorageassetmanagementreservoir@pge.com).

2. McDonald Island - Operating Procedures - Non-Platform Uphole Safety Valve (UHSV) Annual Leak Test - Drawing Number 0800662 4/14/16

2.1. Revisions

APPROVED BY		REV	DATE	DESCRIPTION	GM	DWN	CHKD	SUPV	APVD
LDK7	AAR3	0	3/17/2016	Issued for use as 4/14/16 edition	31103200	TFM0	A3BZ/BKZ1		G1CC/PXT6

2.2. Introduction

This procedure describes an annual test for non-platform wells in service (i.e., fully pressurized).

This procedure applies to all Gas personnel whose work includes field testing valves.

SAFETY

Working outdoors on Gas equipment may result in exposure to environmental hazards, including heat, cold, and inclement weather.

Exposure and reaction to stings or bites from bees, ticks, snakes, and other wildlife also may occur when implementing this procedure.

Slips, trips, and falls and associated cuts, bruises, sprains, and worse can occur when walking on steep, unstable, uneven, slippery, or wet surfaces.

To minimize disturbance, a buffer of 15-30 feet is required if nesting birds are discovered.

2.3. Testing Procedure

1. **BEFORE YOU START**

   a. Schedule the job with Gas Operations.

   b. If necessary, request proper clearance to remove well from service.

c. Gather all appropriate personal protective equipment (PPE) per the Gas Operations Matrix.

d. Gather the following:

- Calibrated gauges
- Calibrated volume measurement and appropriate sized and pressure rated hose
- Job Safety Site Analysis (JSSA)
- McDonald Island UHSV Test Form

2. UHSV LEAK TEST

a. **CHECK** with Operations and inform the operator of the testing (about 4 hours).

b. **CLOSE or CHECK CLOSED** the following:

i. Riser Valve V-15

ii. Master Gate Valve V-1

iii. Casing Wing Valve V-5

c. **INSTALL** blow off stacks to blow down runs.

d. **BLOW DOWN** tubing and casing runs at valve A and valve B.

e. **VERIFY** the following:

i. Tubing, casing, separator, and volume tank are at zero.

ii. UHSV (V-3 and V-6) are CLOSED.

f. **CLOSE** Blow Down Valves V-A tubing and V-B casing runs.

g. **INSTALL** gauges on tubing and casing header line to check for pressure.

h. Ensure all valves are CLOSED.

i. **OPEN** Master Gate V-1 and Casing Wing V-3 to start test.

j. Use the McDonald Island UHSV Test Form and RECORD the pressures on tubing and casing runs:

    i. At 15 minutes.

    ii. 1 hour later to completed test.

k. Slowly **OPEN** Riser Valve V-15 to pressure up lines.

l. **RESET** relays R5 and R7 to return well back to normal operations.

m. Confirm the well returns to NORMAL.

3. END OF TEST

a. **NOTIFY** Operations on completion of testing.

b. Immediately **REPORT** any abnormal issues to the Operations supervisor.

c. Ensure the test form is filled out completely, including the tester's LAN ID, DATE, and TIME.

d. **SCAN AND SECURELY FILE** a local hard copy of each data form.

e. **EMAIL** scanned copies to the Operations supervisor and Reservoir Engineering (gasopsstorageassetmanagementreservoir@pge.com).

3. Pleasant Creek Station - Operating Procedures Uphole Safety Valve (UHSV) Annual Leak 10/20/16

3.1. Revisions

APPROVED BY		REV	DATE	DESCRIPTION	GM	DWN	CHKD	SUPV	APVD
LDK7	AAR3	0	10/20/2016	Issued for use as 10/20/16 edition	31103 200	TFM0	A3BZ/ JCC4	AOO2	DDT8/ BKZ1

3.2. Introduction

This procedure describes a semi-annual function test for wells in service (i.e., fully pressurized).

This procedure applies to all Gas personnel whose work includes field testing valves.

SAFETY

Working outdoors on Gas equipment may result in exposure to environmental hazards, including heat, cold, and inclement weather.

Exposure and reaction to stings or bites from bees, ticks, snakes, and other wildlife also may occur when implementing this procedure.

Slips, trips, and falls and associated cuts, bruises, sprains, and worse can occur when walking on steep, unstable, uneven, slippery, or wet surfaces.

To minimize disturbance, a buffer of 15-30 feet is required if nesting birds are discovered.

3.3. Testing Procedure

1. **BEFORE YOU START**

   a. Schedule the job with Gas Operations.

   b. If necessary, request proper clearance to remove the well from service.

   c. Gas Pipeline Operations and Maintenance (GPOM) must notify Reservoir Engineering at least 96 hours before testing.

   d. Reservoir Engineering must notify the DOGGR at least 48 hours before testing.

   e. Gather all appropriate personal protective equipment (PPE) per the Gas Operations Matrix.

   f. Gather the following:

      - Calibrated gauges
      - Job Safety Site Analysis (JSSA)
      - Pleasant Creek UHSV Test Form

2. **PERFORMING THE UHSV TEST**

   a. **CHECK** with Operations and inform the operator of the testing.

   b. **CLOSE/CHECK** the following:

      i. V-5

      ii. V-6

      iii. V-7

      iv. V-8

   c. **CHECK/OPEN** the following:

      i. Wing Valve V-1

      ii. Master Gate Valve V-2

d. **CLOSE/CHECK CLOSE** both the UHSVs by tripping them at the control panel.

e. **OPEN** vents between V-5, V-6, V-7, and V-8 and the UHSVs.

f. **VENT** the gas to atmosphere.

g. **MEASURE and RECORD** the pressure build-up using the Pleasant Creek UHSV Test Form.

    i. **INSTALL** the gauge on one vent on the tubing side.

    ii. **CLOSE** the remaining vents on this side only.

    iii. **RECORD** the pressure build-up on the test form:

        1. After 15 minutes.

        2. Again in 1 hour.

h. **CLOSE** the vent valve.

i. **REMOVE** the gauge from the vent valve.

j. **INSTALL** the gauge on one vent on the casing side.

k. **CLOSE** the remaining vents on this side only.

l. **RECORD** the pressure build-up on the test form:

    i. After 15 minutes.

    ii. Again in 1 hour.

m. **CLOSE** the vent valve.

n. **REMOVE** the gauge from the valve.

o. IF the leak is excessive or will not blow down enough to safely install the gauge,

    THEN verify the source of leak by alternately closing the master gate valve and the wing valve.

    - This will identify which UHSV is leaking.

p. IF the leak is still excessive with the two UHSVs closed, THEN the source of gas is through V-5, V-6, V-7, and/or V-8.

- This will necessitate CLOSING/CHECK CLOSING V-12, V-13, and venting all sections between V-3 and V-4 and V-12 and V-13.

q. Once it is deemed safe to do so:

   i. Install the gauge.

   ii. Proceed to measure pressure build-up.

r. Once the gauge is connected:

   i. **OPEN** the master gate valve and the wing valve separately.

   ii. Measure and record the pressure build-up.

3. RETURNING TO SERVICE

a. **REMOVE** the gauge.

b. **CHECK OPEN** V-13 to re-pressurize the piping.

c. **CLOSE** the vent(s) after purging.

d. **CHECK OPEN** Wing Valve V-1.

e. **PURGE and CLOSE** the vent(s).

f. **RE-PRESSURIZE** the piping.

g. **CHECK OPEN** Wing Valve V-12.

h. **CHECK OPEN** Master Gate Valve V-2.

i. **OPEN** the appropriate UHSV(s), per operational needs, at the control panel.

j. **NOTIFY** Operations that the testing is finished.

k. **REPORT** any abnormal issues to the Operations supervisor.

l. Ensure the Pleasant Creek UHSV Test Form is completely filled out, including the tester's LAN ID and DATE.

m. Scan and securely file a local hard copy of each data form.

n. Email scanned copies to the Operations supervisor and Reservoir Engineering (mailto:gasopsstorageassetmanagementreservoir@pge.com(gasopsstorageassetmanagementreservoir@pge.com).

4. Los Medanos Station - Operating Procedures Uphole Safety Valve (UHSV) Annual Leak Test– (Drawing Number 0800608) 10/20/16

4.1. Revisions

APPROVED BY		REV	DATE	DESCRIPTION	GM	DWN	CHKD	SUPV	APVD
LDK7	AAR3	0	10/20/2016	Issued for use as 10/20/16 edition	31103 200	TFM0	A3BZ/JC C4	AOO2	DDT8/ BKZ1

4.2. Introduction

This procedure describes a semi-annual function test and an annual pressure test for wells in service (i.e., fully pressurized).

This procedure applies to all Gas personnel whose work includes field testing valves.

SAFETY

Working outdoors on Gas equipment may result in exposure to environmental hazards, including heat, cold, and inclement weather.

Exposure and reaction to stings or bites from bees, ticks, snakes, and other wildlife also may occur when implementing this procedure.

Slips, trips, and falls and associated cuts, bruises, sprains, and worse can occur when walking on steep, unstable, uneven, slippery, or wet surfaces.

To minimize disturbance, a buffer of 15-30 feet is required if nesting birds are discovered.

4.3. Testing Procedure

1. **BEFORE YOU START**

   a. Schedule the job with Gas Operations.

   b. If necessary, request proper clearance to remove the well from service.

c. Gas Pipeline Operations and Maintenance (GPOM) must notify Reservoir Engineering at least 96 hours before testing.

d. Reservoir Engineering must notify the DOGGR at least 48 hours before testing.

e. Gather all appropriate personal protective equipment (PPE) per the Gas Operations Matrix.

f. Gather the following:

- Calibrated gauges
- Job Safety Site Analysis (JSSA)
- Los Medanos UHSV Test Form

2. PERFORMING THE UHSV TEST

a. The UHSV must be reopened locally for semi-annual testing.

b. **CHECK** with Operations and inform the operator of the testing.

c. **CLOSE** V-9.

d. **CHECK OPEN**:

- Wing Valve V-12
- Master Gate Valve V-13

e. **CLOSE/CHECK** close both UHSVs by tripping them at control panel.

f. **CLOSE** the hydraulic supply needle valve at both actuators.

g. **OPEN** vents between V-9 and the UHSVs.

h. **VENT** the gas to atmosphere.

i. **INSTALL** the gauge on one vent.

j. **CLOSE** the remaining vents and Master Gate Valve V-13.

k. Using the Los Medanos UHSV Test Form, **RECORD** the pressure build-up:

i. After 15 minutes.

ii. Again in 1 hour.

l. **OPEN** Master Gate Valve V-13.

m. **CLOSE** Wing Valve V-12.

n. **RECORD** the pressure build-up on the test form:

i. In 15 minutes.

ii. In 1 hour.

o. IF the leak is excessive or won't blowdown enough to safely install the gauge,

THEN verify the source of leak by alternately closing the master gate valve and the wing valve.

- This will identify which UHSV is leaking.

p. IF the leak is still excessive with the two UHSVs closed,
THEN the source of gas is through V-9.
This will necessitate closing V-8 and venting between V-8 and V-9.

q. Once it is deemed safe to do:

i. **INSTALL** the gauge.

ii. Proceed to measure pressure build-up.

r. Once the gauge is connected:

i. OPEN Master Gate Valve V-13 and Wing Valve V-12 separately.

ii. **MEASURE** and **RECORD** the pressure build-up.

3. RETURN TO SERVICE

a. **REMOVE** the gauge.

b. **CHECK OPEN** V-8.

c. **OPEN** V-9.

d. **PURGE** and **CLOSE** the vent(s).

e. **RE-PRESSURIZE** the piping.

f. **CHECK OPEN** Wing Valve V-12.

g. **CHECK OPEN** Master Gate Valve V-13.

h. **OPEN** the appropriate UHSV(s), per operational needs, by placing the selector switch in the appropriate position in the control bldg.

i. At the well, **OPEN** both hydraulic supply needle valves that were closed in step 1.3 above.

j. **NOTIFY** Operations that the testing is finished.

k. Immediately report any abnormal issues to the Operations supervisor.

l. Ensure the Los Medanos UHSV Test Form is completely filled out, including the tester's LAN ID and DATE.

m. Scan and securely file a local hard copy of each data form.

n. Email scanned copies to the Operations supervisor and Reservoir Engineering (mailto:gasopsstorageassetmanagementreservoir@pge.com(gasopsstorageassetmanagementreservoir@pge.com).

Underground Storage Risk and Integrity Management Plan

Appendix J, Practice 6 – Wellhead (Christmas Tree) Pressure Monitoring

Page 1 of 2

CHRISTMAS TREE PRESSURE MONITORING

Purpose: Provide standards and procedures for Wellhead (Christmas tree) pressure monitoring.

What: A Wellhead (Christmas tree) is a typical vertical assembly of mechanical elements used in exploration and production of Oil and gas. It is mainly used for fluid control in and out of the well-bore. This test is to monitor Christmas tree pressure on all storage wells to provide wellhead integrity assurance and public and employee safety.

Figure J-1. A Typical PG&E Christmas Tree.

Why: This is to evaluate integrity of wellhead seals for maintenance and repair, if necessary, to assure wellhead integrity, and reduce risk of unsafe operation. "For surface and subsea Christmas trees, the production tree valves are to be tested in the direction of flow. If a well does not have a positive closed-in pressure, then testing the master valve in the direction of flow may not be practical. In this case, the master valve may be inflow tested.

When: Quarterly.

Who:

- Reservoir Engineering (RE) collects quarterly Christmas tree pressure data
- RE reviews quarterly Christmas tree pressure data
- RE inputs the quarterly Christmas tree pressure data into the GSDB
- RE evaluates and analyzes the quarterly Christmas tree pressure data trends

Procedure:

1. Collects quarterly Christmas tree pressure data on all storage wells at quarter end using well pressure data forms for Los Medanos, McDonald Island, and Pleasant Creek.
2. Reviews quarterly Christmas tree pressure for reasonableness.
3. Inputs the quarterly Christmas tree pressure in the GSDB.
4. Reviews and analyzes the quarterly Christmas tree pressure data comparing to previous quarters.
5. Compile and trend historical data if available.
6. Develop decision criteria for acceptable operating limit for each wellhead variables.
7. Recommends action plans for wellhead maintenance activities.

Forms

1. Los Medanos well pressure data form.
2. McDonald Island well pressure data form.
3. Pleasant Creek well pressure data form.

Underground Storage Risk and Integrity Management Plan

Appendix K, Practice 7 – Mechanical Integrity Test Acceptance and Frequency

Page 1 of 1

The following flow chart illustrates the pressure testing process that PG&E utilizes for performing and assessing MIT testing. Re-assessment testing is scheduled based upon a successful pressure test and may be more frequent if remediation measures are needed to address an integrity issue prior to the planned reassessment pressure test.

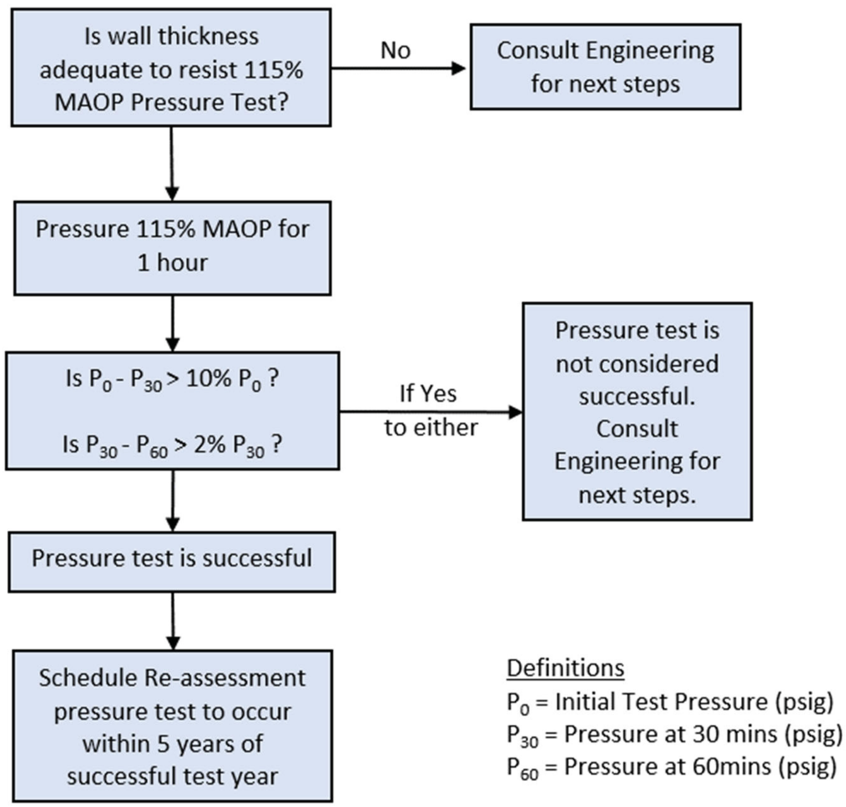


Figure K-1 – Well MIT Process

Underground Storage Risk and Integrity Management Plan

Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring

Purpose: Provide guidance and standard for creating annular pressure and gas sampling monitoring and action plans.

What: This is to establish action plans for monitoring the annular pressures.

Why: Monitor the annular space pressure to indicate potential well integrity issues, identify gas migration issues, and utilize the sampling data for the future usage for well casing integrity and employee and public safety.

When: Pressure collection is completed in accordance with Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring.

Who:

- GPOM or Reservoir Engineering collects pressure
- Reservoir Engineer directs RE Specialist to sample and/or conduct blow down/build-up test
- PG&E Load Center or other qualified lab analyzes the gas samples
- RE Specialist reviews and enters pressure data, venting rate, and/or gas sample results for reasonableness and distributes to Engineers.
- Reservoir Engineering Engineers evaluate and analyze data

Procedure:

1. GPOM and Reservoir Engineering collect pressure data per Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring.
2. Reservoir Engineer reviews received pressure data for the following:
    a. wells with any amount of annular pressure
    b. wells with annular pressure data equal to or greater than 120 psig
    c. well surface casing annular pressure relationship to established Maximum Allowable Surface Casing Pressure (MASCP). MASCP is equal to the surface casing depth (feet) x 0.25 psi.
    d. wells with anomalous data or trends indicating integrity breach

    __Note:__ any wells identified under items 2(d) shall be reported immediately to the Reservoir Engineering director, manager, supervisor and engineer. A plan of action should be developed to assess the anomalous pressure and could include shutting in the well immediately, conducting injection or withdraw testing, and collecting additional pressure data. For anomalous events, if the trend seems unusually large or if any of the survey data looks odd enough to require confirmation, request a re-test of the annular survey.

3. Reservoir engineer reviews existing monitoring and action plans and where needed directs RE Specialist to sample and/or conduct blow down/build-up test. A standard test shall be conducted in accordance with Table L-1 unless otherwise directed by Engineer.

4. RE Specialist delivers the annular gas samples to PG&E load center for analysis.

5. Reservoir Engineering inputs the pressure, venting rate, and/or gas sample results in the GSDB and distributes the Reservoir Engineer.

6. Reservoir Engineer trends pressure, venting rate, calculates emissions volume, and gas sampling data and performs field and well integrity evaluation consulting the well files for any historical data points and in review of possible causes and remediation in Table L-2.

    a Data from the test and sampling shall be stored in the well's monitoring and action plan for trending analysis that includes pressure versus time and historical sampling comparisons

    Note: The monitoring and action plan shall include: first time event; historical pattern of the annular pressure in about this range of volume; historical pattern of annular pressure but present survey finds more volume than usual; or other appropriate comment based on the history. Commentary may also summarize information: well completion and rework history, history of annulus pressure and any prior attempts to define sources of pressure or remedial/repair attempts, log review data (gamma ray-neutron, cement bond, and casing inspection log (e.g. MFL or Ultrasonic)).

    b Remedial actions could be determined and the well will remain out of service until repairs are completed or the well will be placed back in service.

7. Reservoir Engineer documents recommendation for action. This recommendation may include: continue to monitor; run log investigations or other physical tests; gas sampling; wellhead packing; or other remedial action. The action should be related to the amount of the gas loss, safety and environmental concerns.

END OF PRACTICE

Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring
Page 3 of 4

Table L-1

Standard Annular Test
Collect gas sample(s).
Conduct a surface casing blow down and build up test.
Record blowdown pressures at 1, 2, 3, 4, 5, 10, 15, 20, 25, and 30 minutes.
Record buildup pressures at intervals specified by engineer.

Table L-2

Potential Cause of Annular Pressure		**Analysis Results or Symptom**	**Potential Remedial Solutions**
1	Loss of integrity in wellhead seals	Pressure is variable but often could be high pressure but quick blow down due to small volume since a very limited space can be filled and could also see spikes with temperature impact.	Inject packing at wellhead seals
2	Gas migration behind pipe through cement sheath of low integrity	Pressure may appear highly variable and gas may accumulate considerable volume over time. This is dependent on the transmissibility of the leak path and may depend on the ability of reservoir pressure to overcome the hydrostatic head of liquid in the annulus. It may also depend on whether shallow permeable zone has been charged by gas moving in the annulus over time. Good application for log investigations – cement bond, noise, temperature, neutron, etc.	Remediation may include squeezing the leak path itself, block squeezing or squeeze cementing above the current top of cement (assuming there is no formation below that point that can be charged up as a leak collection pool for the gas). Seal-tite (and perhaps others) also claims to have a chemical solution, injecting a polymer down the annulus that gels at a pressure differential (this can be fairly expensive). Plugging the downhole formation and sealing it off from the annulus is an option if the well has little or no value in operations. Milling a window and squeeze cementing, along with running and cementing a full liner, also has been successful at shutting off these sorts of leaks

Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring
Page 4 of 4

Table L-2 (cont.)

Potential Cause of Annular Pressure		Analysis Results or Symptom	Potential Remedial Solutions
3	Casing collar leaks	**Type 1)** Pressure build may come and go and manifest irregularly if hydrates can form to seal off small leaks. **Type 2)** Substantial leaks will likely always show up suddenly. Noise, temperature, and neutron logs can be effective at defining the leak point(s).	Remedial solutions include liners (cemented or on packers), internal casing patches, chemical seals (Seal-tite, see above in #2), or squeeze cementing. If close to the surface, sometimes the joints can be backed off and replaced.
4	Leak due to corrosion hole	This type of leak will suddenly manifest itself and can be variable in its pressure and rate depending on the size and depth of the hole and the annulus medium through which the gas must travel.	Remedial options include installation of liners, patches, back off casing and replace (if near the surface and un-cemented), etc. The probable presence of a pit or of pre-existing conditions leading to progressive corrosion pit growth should show up on an MFL, ultrasonic log or other similar casing inspection survey. Casing should be recovered where possible for pit geometry and depth characterization; a casing inspection log (e.g. MFL or ultrasonic) should be run prior to the casing recovery.
5	Leak due to gas emanating from a natural gas-bearing zone which is not isolated from the annulus	The presence of naturally occurring gas should be verified via well history and local information. Gas sampling to determine any differences between storage gas and native gas from another zone is important. It may be that gas in the annulus is a combination of native gas from another zone and gas leaking to or through the annulus from storage for whatever reason.	Isolation efforts as described in (4) above are the best way to treat this problem if the amount of gas creates safety or environmental problems, or if native gas leaks may be combined with storage gas leaks. Log investigations can clarify issues related to potential dual source problems

Underground Storage Risk and Integrity Management Plan

Appendix M, Practice 9 - Individual Well Performance Monitoring

INDIVIDUAL WELL PERFORMANCE MONITORING

Purpose: Provide standards and procedures for individual well performance monitoring.

What: This plan is to provide individual well injection and withdrawal performance monitoring. Individual well performance monitoring is the real-time surveillance solution that combines well data analysis to operator and Engineer's expertise thereby allowing them to make decisions based on hard facts and data collected.

Why: This document is to provide process to monitor individual well performance in order to optimize individual injection and withdrawal flow rate and troubleshoot well performance issues. It is important to provide system operations, marketing, and operations and maintenance organizations the baseline capacity to meet the needs of PG&E storage customers throughout the year. Through proper monitoring of wells, underperforming wells can be identified. This can help avoid some major issues such as:

- Void deferred production
- Reduce well asset maintenance costs
- Increase production
- Prioritize and optimize production operations
- Maximize field efficiency and oil recovery

When: On-going.

Who:

- UGS O&M provides daily well status
- Reservoir Engineering (RE) provides weekly well status and pressure reads
- RE reviews well status
- RE evaluates well performance
- RE communicates changes in well performance

Procedure:

1. UGS O&M informs RE any well performance issues.
2. RE logs into the Cimplicity control system to review the issues.
3. RE investigates the above and troubleshoot, if necessary.
4. RE reports the results of investigation and troubleshoot.
5. RE inputs to the GSDB to keep track of well performance and remediation prioritization.
6. RE evaluates individual well performance by taking into account of the previous individual flow test results, interference and past performance issues.
7. RE communicates the results to Gas System Operations, Wholesale Marketing & Business Development, Station Services, Operations & Maintenance, and Gas System Planning to provide well performance updates in a timely manner.

Underground Storage Risk and Integrity Management Plan

Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring

WELLHEAD ANNULI MONITORING

Purpose: PG&E's current well construction can include up to four separate annuli requiring monitoring based on well configuration: 1-surface casing, 2-production casing, 3- tubing, and 4- cemented inner string where installed. Installation of the inner string is typically a remedial activity used during reworks.

Why: Wellbore annuli pressure monitoring allows for field and well integrity evaluation to ensure safety, assurance of no gas loss for inventory verification, and utilization for gas reservoir engineering analysis. Surface wellheads are used to support casing & tubing strings, isolate/and control pressure during the drilling operation and monitor annulus casing during production.

What: Wells that have a cemented inner casing string installed and requires a fourth point of monitoring. See Figures N-1 and N-2 below, for typical wellhead configuration with 3 monitoring and 4 monitoring points, respectively. Figure N-3 provides additional clarity on downhole construction of concentric casing strings. Note: the current list of wells with inner strings is maintained on Reservoir Engineering Sharepoint and updated at the conclusion of rework season for any wells configured with an inner string.

When: Daily (GPOM) & Weekly (RE Specialist)

Who:

- GPOM collects wellhead annulus pressure data to meet daily compliance requirement.
- RE Specialist collects pressures on a weekly basis and spot flow rates.
- RE reviews, inputs and trends data. RE must be notified to approve of any exceptions to the compliance requirements noted above.

Procedure:

1. GPOM/RE Specialist uses calibrated portable gauges to collect daily pressure reads at each well, including injection/withdrawal wells and observation wells, in three PG&E owned gas storage fields. Daily pressures are collected from tubing, casing, surface casing, and inner casing string where installed.
2. GPOM records pressures and remarks using mobile device (PRONTO forms) and submits via mobile application to RE. RE Specialist records pressures, remarks, and spot flow rates in Excel spreadsheet format and submits to RE.
3. RE inputs the received pressure data in the GSDB.

4. RE reviews received pressure data for completeness and reasonableness.

5. RE trends pressure data and performs field and well integrity evaluation activities.

6. RE communicates anomalies per regulations and/or recommends actions to RE Specialist and/or GPOM.

END OF PRACTICE

Figure N1-1. Wellhead with 3 monitoring points

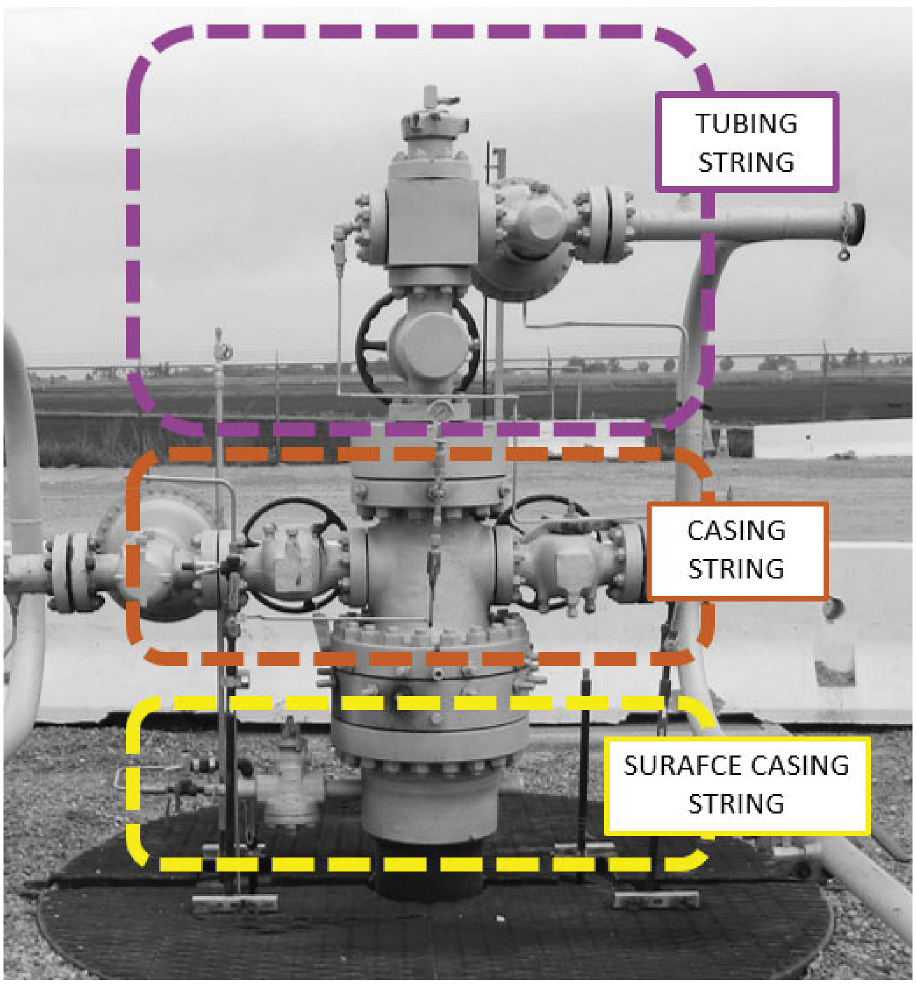
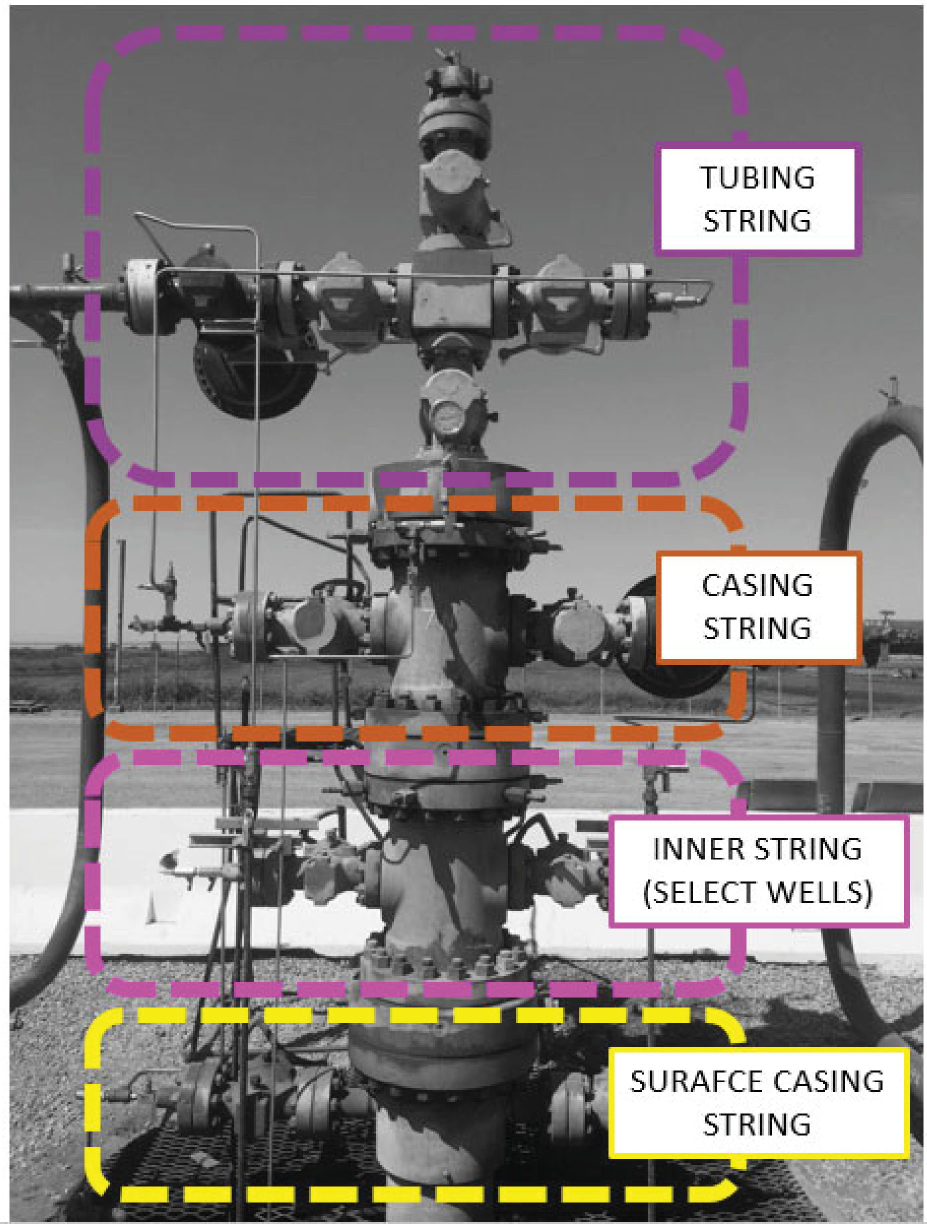
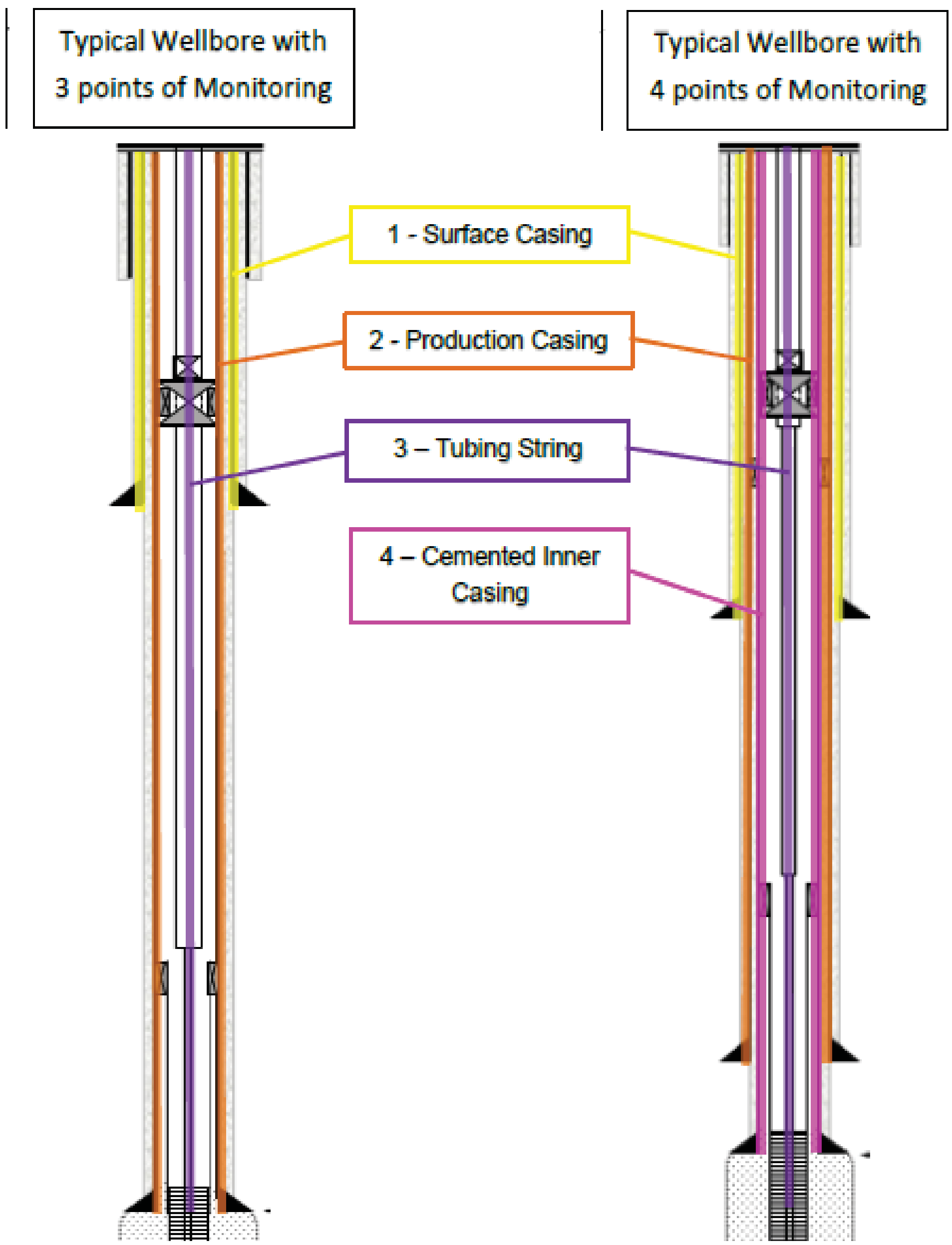


Figure N1-2. Wellhead with 4 monitoring points



Underground Storage Risk and Integrity Management Plan

Figure N1-3, Typical wellbore diagrams for wells with 3 (left) and 4 (right) points of pressure monitoring



Underground Storage Risk and Integrity Management Plan

Appendix O, Practice 11 - Observation and Selected I/W Well Gas Sampling

OBSERVATION WELL GAS SAMPLING

Purpose: Provide standards and procedures for observation and selected I/W well gas sampling.

What: This is to establish the process for taking Observation and selected Injection/Withdraw (I/W) well gas samples to provide an understanding of the storage gas quality, monitor gas movement within a storage zone and to monitor the potential for gas migration away from the storage zone or movement to other porous zones above or below the storage zone. An observation well is used to monitor the operational integrity and conditions in a gas reservoir, the reservoir protective area or the strata above or below the gas storage horizon. Natural gas is injected into the formation, building up pressure as more natural gas is added. “The higher the pressure in the storage facility, the more readily gas may be extracted. I/W Wells are used to inject and withdraw the storage gas.” (GSR Industry Primer).

Why: This is to monitor the well gas samples to improve well integrity monitoring, identify potential storage gas movement / migration issues, differentiate between storage gas and other gases and utilize the sampling data for reservoir engineering analysis. Gas samples are obtained and analyzed to determine if changes in gas composition occur over time. The samples may be taken from OBS wells completed in the storage zone and/or OBS wells completed in porous zones above or below the storage zone. Changes in gas composition may indicate movement of storage gas toward storage boundaries. This information is valuable for identification of potential storage gas migration.

Two of the most important characteristics of an underground storage reservoir are its capacity to hold natural gas for use rate and the rate at which gas inventory can be withdrawn its deliverability rate. Through an observation and I/W well gas sampling program an operator can monitor for gas movement in the reservoir that maybe indications of gas movement or migration.

When: Monthly

Who:

- Reservoir Engineering (RE) collects monthly observation and selected I/W well gas samples
- PG&E Load Center analyzes the monthly observation and selected I/W well gas samples
- RE reviews monthly observation and selected I/W well gas sample results for reasonableness
- RE inputs the monthly observation and selected I/W well gas sample results into the GSDB
- RE evaluates and analyzes the monthly observation and selected I/W well gas sample result trends

Procedure:

1. RE collects monthly observation and selected I/W well gas samples.
2. RE delivers the monthly observation and selected I/W well gas samples to PG&E load center for analysis.
3. RE inputs the monthly observation and selected I/W well gas sample results in the GSDB.
4. RE reviews and analyzes the monthly observation and selected I/W well gas sample results comparing to the previous monthly storage gas sample results.

    a The following is a summary of questions the Reservoir Engineer attempts to answer in its evaluation of the pressure responses and gas sample data from an OBS well or an I/W well.

    (1) What is the fluid observed in the well – oil, gas, brine, etc.? If gas, does the gas sample reflect native or storage gas?

    (2) Which formation is the well monitoring – the storage zone, fringe area of the storage zone or potential porous zones above or below the storage zone into which gas could migrate?

    (3) Are pressure changes observed at the surface or bottom hole?

Underground Storage Risk and Integrity Management Plan

(4) Status of nearby wells – what does the data from offsetting wells provide?

(5) Well integrity history

(a) Does annular pressure monitoring data indicate the integrity of tubing or casing?

(b) Are apparent defects present on casing inspection logs? If so, what is the rate of change of apparent defects?

(6) Well location – is the well near houses, buildings, roads or waterways?

(7) Does the pressure of this well track closely with the reservoir pressure?

(8) Is this well being used for gas injection and/or gas withdrawal?

(9) Is the drainage area from this well a low percentage?

(10) Is the gas analysis from this well similar to the gas analysis from the remainder of the reservoir?

5. RE determines if any anomalies exist and recommends actions.

Underground Storage Risk and Integrity Management Plan

Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification

FIELD SHUT IN TESTING FOR STORAGE GAS INVENTORY VERIFICATION

Purpose: Provide standards and procedures for field shut in testing for storage gas inventory verification.

What: This plan is to provide process for field shut in testing for storage gas inventory verification.

Why: This document is to provide process for storage gas inventory verification to meet SOX and company accounting and financial reporting requirements.

When: Weekly updates and final reports in November.

Who:

- Reservoir Engineering (RE) obtains weekly pressure reads
- RE obtains extended shut in pressure reads
- RE reviews pressure data
- RE evaluates storage gas inventory and pressure relationship
- RE communicates results

Procedure:

1. Weekly Monitoring:

   a RE obtains weekly wellhead pressure on every available storage wells

   b RE reviews pressure data for reasonableness and anomalies

   c RE calculates weekly average reservoir pressure for each storage field

   d RE plots hysteresis curves for each storage field to monitor behavior relative to history

   e RE reports weekly results

   f RE, if need be, investigates and troubleshoots anomalies of the hysteresis behavior

   g RE communicates findings

2. Annual Inventory Verification: (see “Inventory Study Definitions” below for additional detail and definitions)

   a RE obtains extended shut in wellhead pressure on every available storage wells at low inventory after the winter withdrawal and at high inventory after the summer injection

   b RE Conducts a production pressure-decline analysis that includes the following steps:

   c Monitoring of BHP/z, where “z” is the gas compressibility factor, versus inventory on a routine basis.

   d Individual wellhead pressures are recorded during the field shut-in tests but prior to interference from hysteresis effects or changing reservoir pore volumes.

   e Well pressures are reviewed for evidence of leaks and/or the presence of fluid in the wellbore. Pressure data is contoured to help identify if any low pressures are observed.

   f Surface pressures are converted to BHP by adding the weight of the gas column determined by direct BHP measurements and/or by calculation.

   g Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification

   h The factor z is computed using the properties of the stored gas from analyses of field and/or well samples.

   i BHP/z pressure values are calculated for each well and an average BHP/z is determined, or a single BHP/z is calculated from a field average wellhead pressure.

   j The average field pressures are evaluated to establish a field stabilization trend or by using the actual production pressure decline if timing of the shut-test precludes elimination of reservoir effect phenomena.

   k The average BHP/z is then plotted versus the company book volumes.

   l RE inputs to the GSDB to keep track of well performance and remediation prioritization.

   m RE evaluates individual well performance by taking into account of the previous individual flow test results, interference and past performance issues.

   n RE communicates the results to GSO, WM&BD, and GSO Planning to provide well performance updates in a timely manner.

Inventory Study Definitions

The following definitions are consistent with the BOP process which relates to the accounting and treatment of storage gas.

- Inventory: All gas molecules in the storage reservoir expressed in a volume at standard temperature and pressure.
- Adjustment(s): A volume of gas that impacts storage Inventory deriving from meter errors, fuel usage, diffuse gas losses and/or other operational factors.
- Non-Recoverable Gas: A volume of gas which supports the storage cycle under stabilized pressure conditions but cannot be recovered economically upon field abandonment. The initial determination of Non-Recoverable Gas will be made at or after the abandonment of the storage reservoir begins excluding volumes previously deemed Non-Recoverable Gas and written down. Any identified gas volume which is deemed Non-Recoverable Gas shall be written down at the time a determination of such volume is made (pursuant to XX Policy).
- Migrated Gas: A volume of gas believed to have been present in a storage reservoir which subsequently has left the storage reservoir and no longer supports its cyclic storage operation. Any Identified gas volume which is deemed Migrated Gas shall be written down.
- Identified: The nature or the origin of the Adjustment, Non-Recoverable or Migrated Gas volume(s) is known to a Reasonable Engineering Certainty. No further research is required.
- Inconsequential: To a reasonable person, there is lack of worth or importance, and it is trivial in relation to the lowest level of external financial reporting. Or, lacking in worth or importance as deemed by a reasonable person.
- Consequential: To a reasonable person, it has magnitude or importance. Or, having magnitude or importance as deemed by a reasonable person.
- Unresolved/Loss Contingency: Items that require further research and/or additional data to determine proper classification as to a possible gain or loss and whose ultimate resolution depends upon whether one or more future events occur or fail to occur. The occurrence of such events can range from Probable to Remote as follows:
    - *Probable*. The future event or events are likely to occur.
    - *Reasonably Possible*. The chance of the future event or events occurring is more than Remote but less than Probable.
    - *Remote*. The chance of the future event or events occurring is slight.
- Annual Inventory Report: An annual analysis of the gas storage Inventory including, where applicable, Adjustments, Migrated Gas and Non-Recoverable Gas in each storage reservoir owned and/or operated, or in which an interest is owned by PG&E, based on operating data and engineering studies.
- Reasonable Engineering Certainty: A conclusion arrived at by a qualified engineer using all the pertinent available information and employing industry accepted engineering techniques and scientific concepts.

Underground Storage Risk and Integrity Management Plan

In addition to the terms identified above, a number of practical terms are used in this report to describe operational issues related to management of storage inventory. These terms identify portions of the booked gas volume which do not exhibit a pressure response in the storage reservoir during the semi-annual shut-in tests. The terms and their definitions are as follows.

- Non-Effective Gas: The volume of gas that does not exhibit a pressure response in the storage reservoir when a pressure decline analysis (PDA) is performed based on the fall and spring shut-in pressure data which, in general, are not indicative of fully stabilized storage reservoir conditions.
- Impounded Gas: That portion of the Non-Effective Gas which supports the storage cycle under stabilized pressure conditions but is not readily producible during the operating withdrawal cycle.
- Non-Effective Gas Calculation: The volume of Non-Effective Gas for an operating cycle is determined graphically by performing a PDA. The analysis involves measuring the volume of gas withdrawal from a storage reservoir and well shut-in pressures before and after withdrawal takes place. After plotting the starting and ending total Inventory with the corresponding bottom hole pressures corrected to account for the departure from the ideal gas law, a straight line is drawn through the points and extrapolated to zero psi. This line is used to determine the Non-Effective Gas volume for the operating cycle.

The Pressure Decline Analysis (PDA) involves the following steps:

1. Individual wellhead pressures are recorded during the shut-in tests which take place every spring and fall and/or representative indicator well pressures are periodically recorded during storage operations. If inconsistencies are observed for individual pressures, estimates are made.
2. The wellhead pressures are converted to absolute by adding the barometric pressure.
3. These pressures are converted to BHP by adding the weight of the gas column using the well bore gas gradient and/or by calculation.
4. The compressibility factor z is computed using the properties of the stored gas.
5. The BHP/z pressure values are calculated for each well or a single BHP/z is calculated from field average wellhead pressures and/or representative indicator wells.
6. The BHP/z values are weighted to obtain a weighted average field BHP/z.
7. The weighted average field pressures are evaluated through the semi-annual shut-in test.
8. The final spring and fall BHP/z pressure values are plotted versus the total field inventory for those days. A straight line is drawn through the points and extrapolated to zero psi.
9. The Non-Effective Gas volume is determined at zero psi rather than the BHP at abandonment.
10. Pressure decline lines are plotted for the six most recent consecutive years of operation and are evaluated in terms of continuing or revising the operating mode to improve field performance.
    - Gas-Per-Pound (Apparent/Effective Pore Volume): Reservoir gas-per-pound (GPPr) or Apparent Pore volume (PV) is the slope of the line connecting an individual BHP/z versus total field content and zero psi versus zero total field content. This is done for both the spring and fall shut-in test points and/or two other points determined by the intersection of the production decline trend (BHP/z) and two constant BHP/z's (generally one at maximum working inventory and one at low inventory). Cyclic Gas-Per-Pound (GPPc) or Effective

Pore Volume (PVe) is the slope of the line that connects the current shut-in point and the previous shut-in point.

- Gas-Per-Pound Calculations: GPPr is calculated using the following steps. Note that steps 1 – 8 in the Non-Effective Gas calculation have previously been performed.

1. For each semi-annual shut-in point, calculate total content divided by BHP/z and/or use points determined by production decline trend and the intersection of two constant BHP/z points.
2. Graphically connect all calculated points.

Cyclic Gas-Per-Pound (GPPc) is calculated using the following steps. Note that steps 1 – 8 in the Non-Effective Gas calculation have previously been performed.

1. After each semi-annual shut-in test, calculate previous total field content less the current total field content divided by the previous BHP/Z less the current BHP/z and/or use the production decline trend and the corresponding inventories consistent with the two constant BHP/z points.
2. All calculations that are performed using a spring shut-in as the current shut-in generate one set of data (the slope of all fall – spring cycle lines). Calculations performed using the fall shut-in as the current shut-in generate a second set of data (the slope of all spring-fall cycle lines) and/or in the case of the production decline trend use the two other points determined by the intersection of the production decline trend (BHP/z) and the two constant BHP/z points (one high and one low).
3. Graphically connect calculated points of the same cycle, for example, all of the calculated slopes for the fall – spring cycle are connected and/or the two but constant BHP/z points.

Operations from cycle to cycle can impact the storage reservoir pressure response data that is gathered during the semi-annual shut-in test. Thus, it is the trend over several cycles that could indicate what may be occurring in the storage reservoir.

- Pore Volume Ratio: The ratio of current pore volume compared to the original pore volume.
- Pore Volume Ratio Calculation: Pore Volume Ratio (PVR) is calculated using the following steps. Note that steps 1 – 8 in the Non-Effective Gas calculation have previously been performed.

1. Calculate the original BHP/z times the current total content divided by the original total content times the current BHP/z for each semiannual shut-in and/or the two points generated by the production decline trend and the constant BHP/z points.
2. Graphically connect all calculated points.

- Inventory Variance: The difference between book (or metered) total inventory and total content calculated using a pressure-volume material balance relationship.
- Inventory Variance Calculation: Inventory Variance is calculated using the following steps. Note that steps 1 – 8 in the Non-Effective Gas calculation have previously been performed.

1. Calculate the total content using the original discovery line and the current BHP/z.
2. Subtract the calculated total content from the current metered total content.
3. Graphically connect all calculated points. However, there may be merit in connecting spring points as one data set and fall points as a second data set.

Annual Inventory Verification:

1. RE obtains extended shut in wellhead pressure on every available storage wells at low inventory after the winter withdrawal and at high inventory after the summer injection
2. RE Conducts a production pressure-decline analysis that includes the following steps:
3. Monitoring of BHP/z, where “z” is the gas compressibility factor, versus inventory on a routine basis.
4. Individual wellhead pressures are recorded during the field shut-in tests but prior to interference from hysteresis effects or changing reservoir pore volumes.
5. Well pressures are reviewed for evidence of leaks and/or the presence of fluid in the wellbore. Pressure data is contoured to help identify if any low pressures are observed.
6. Surface pressures are converted to BHP by adding the weight of the gas column determined by direct BHP measurements and/or by calculation.
7. The factor z is computed using the properties of the stored gas from analyses of field and/or well samples.
8. BHP/z pressure values are calculated for each well and an average BHP/z is determined or a single BHP/z is calculated from a field average wellhead pressure.
9. The average field pressures are evaluated to establish a field stabilization trend or by using the actual production pressure decline if timing of the shut-test precludes elimination of reservoir effect phenomena.
10. The average BHP/z is then plotted versus the company book volumes.
11. RE inputs to the GSDB to keep track of well performance and remediation prioritization
12. RE evaluates individual well performance by taking into account of the previous individual flow test results, interference and past performance issues.
13. RE communicates the results to GSO, WM&BD, and GSO Planning to provide well performance updates in a timely manner

DATA UNCERTAINTY

Data uncertainty is inherent in the analysis addressed in this appendix. An integral part of the analysis procedures is the investigation, documentation, and mitigation of sources of uncertainty in data collected for inventory assessment purposes and the analysis of that data, including but not limited to calculations, gas measurement procedures, and shut-in pressure stabilization time.

Underground Storage Risk and Integrity Management Plan

Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties

MONITORING THIRD PARTY ACTIVITIES INSIDE AND OUTSIDE OF GAS STORAGE PROPERTIES

Purpose: Provide standards and procedures for monitoring third party activities inside and outside of gas storage properties.

What: This is to monitor third party activities inside and outside of gas storage asset properties including drilling and production for potential extraction of storage gas.

Why: This is to protect gas storage reservoir integrity and protect against loss of storage gas from potential extraction of storage gas by third parties.

When: Perform surveillance whenever working in gas storage facilities.

Who:

- Reservoir Engineering (RE) performs surveillance
- RE reviews third party drilling activities.
- RE evaluates potential third-party wells and recommends course of actions, if any.

Procedure:

1. Survey and monitor third party drilling activities inside and outside of gas storage asset properties.
2. Open DOGGR GIS System (Well Finder).
3. Review PG&E and third party permits as well as third party active and idle Wells
4. Obtain well logs from the DOGGR to determine zones of production from third party Permit activities, if available.
5. Obtain periodic wellhead pressures and gas samples from third party wells, if available.
6. Compare storage pressure and storage gas samples with the production wells.
7. Enforce no-drill through rights inside gas storage asset properties.

8. If well is drilled within 75' from the gas storage asset property line, inform the DOGGR to shut down production.

9. Document process and plot well drilling and production activities on reservoir maps.

10. Update and plot activities on reservoir maps as new activities are obtained.

11. Communicate results to the Land, Operations & Maintenance, and Reservoir Engineering departments.

12. If third party drilling activities exhibits potential extraction of storage gas, elevate to higher level management for mitigation decision.

Documentation:

A. Complete review in form "Third Party Monitoring Activities Form.xlsx" located in the G-Drive under folder "Third Party Monitoring."

B. Save completed form with date of review with extension of XXXX_XX_XX (Year-Month-Day)

Underground Storage Risk and Integrity Management Plan

Appendix R, Practice 14 - Downhole Safety Valve (DHSV) Leak-by Testing

DOWNHOLE SAFETY VALVE TESTING

Purpose: Provide standards and procedures for the testing of downhole safety valves.

What: Wells equipped with a “downhole” safety valve (DHSV) or surface controlled subsurface safety valves (SCSSV) typically have valves installed 250 feet below ground level to provide emergency shutdown in the event the storage well cannot be isolated by the wellhead master valve. DHSV valves are surface controlled, hydraulically operated and are “fail safe” type valves (hydraulic control system pressure keeps the valves open, and the valves close on loss of hydraulic control system pressure). This practice uses API Recommended Practice 14B Sixth Edition, September 2015 as guidance in developing the test procedures.

Procedure: See detailed DHSV testing procedures and data collection forms issued by Reservoir Engineering. The following table lists these documents for reference. The most current editions must be obtained from GSAM Reservoir Engineering. Current procedures reside in this IMP as Appendices R1 through R3.

Frequency: Annually, not to exceed 15 months.

Table R-1, Down Hole Safety Valve Guidance Documents

Guidance Doc	Title / Notes	Form
Appendix R.1 McDonald Island Downhole Safety Valve (DHSV) Leak-by Test	Procedure for leak-by testing McDonald Island Station Downhole Safety Valves (DHSV) in fully pressurized well	MI DHSV LEAK TEST FORM.xlsx
Appendix R.2 McDonald Island Downhole Safety Valve (DHSV) Leak-by Test – Well out of Service	Procedure for testing DHSV during station outage at McDonald Island	MI DHSV LEAK TEST FORM.xlsx
Appendix R.3 Downhole Safety Valve (DHSV) Leak-by Testing: Los Medanos	Los Medanos Station Operating Procedures Downhole Safety Valve (DHSV) Test	LM DHSV LEAK TEST FORM _REV1.xlsx

Operating Principle:

The DHSV is usually opened due to the hydraulic connection of the well control at the surface. Hydraulic pressure applied at the control station is related down through the control line thereby forcing a sleeve in the valve to open (slide downwards). This downward movement is due the compression of a large spring which forces the flapper of the valve to open downward. Releasing the hydraulic pressure forces the spring to be pushed backward, thereby collapses the flapper to close.

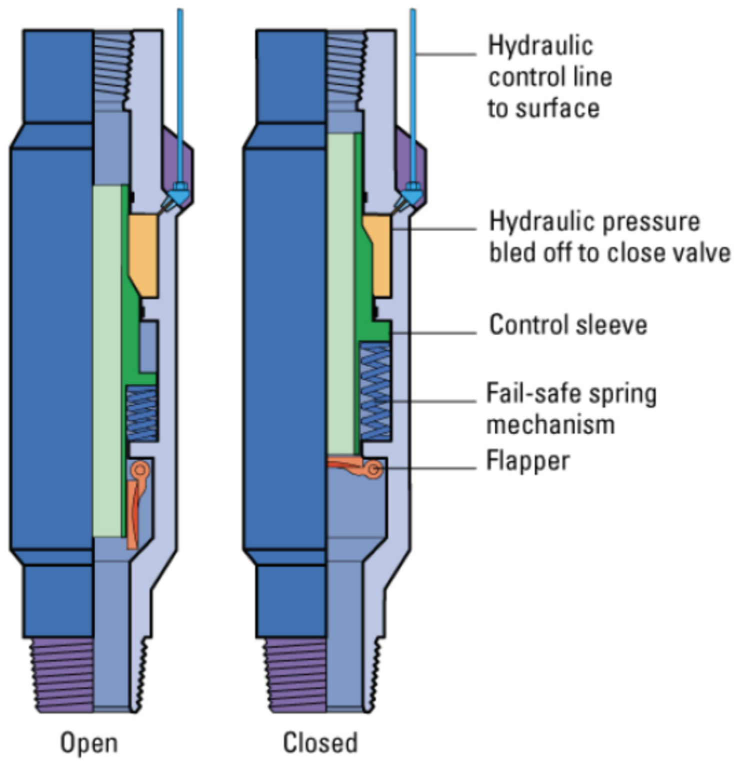


Figure R-1. A DHSV in an Opened And Closed Position

Why: The testing is to ensure that the DHSVs are meeting the State regulation requirements and reliable operations to meet gas system and customer demands. The DHSV is a major preventive measure installed to prevent an uncontrolled release of the reservoir fluid is an emergency scenario such as an explosion or in situation where the wellhead integrity is lost. It is designed in such a way that the production causes it to close while the hydraulic control forces it open. The hydraulic control is usually operated from the surface as indicated earlier.

When: Test under a standard clearance: normally between April and October of the year.

Who:

- Underground Gas Storage (UGS) Operations performs testing. Refer to Station Operating Procedures for Los Medanos, McDonald Island, and Pleasant Creek.
- Reservoir Engineering reviews test data for reasonableness and completeness.
- Reservoir Engineering evaluates test data and assigns ratings to prioritize the malfunctioning DHSVs for replacements.

Evaluation:

1. The results of the evaluations are entered into gas storage database and rated based on the DHSV ratings below.
2. Reservoir Engineering will prioritize the DHSVs replacements and inputs in the GSDB and S1 and S2 processes.

C. Table R-2. RC DHSV, RC-2 DHSV Control Line Ratings

RATING	DHSV/ Control Line Ratings (Pressure Build-up/ 45 mins)
0	No leakage
1	1 to 100 psig
2	101 to 200 psig
3	201 to 300 psig
4	301 or higher

Underground Storage Risk and Integrity Management Plan

Historical Evaluation Prior to 2014:

1. The results of the evaluations are entered into gas storage database and rated based on the DHSV ratings below:
2. Reservoir Engineering will prioritize the DHSVs replacements and inputs in the GSDB and S1 and S2 processes.

Table R-3. RC DHSV Ratings

RATING	RC DHSV/ Control Line Rating (Pressure Build-up/ 45 mins)
0	No leakage
1	1 to 100 psig
2	101 to 200 psig
3	201 to 300 psig
4	301 or higher

Table R-4. RC-2 DHSV Ratings

RATING	RC-2 DHSV Rating (Flow test / 10 mins)
1	≤ 50.0 cu/ft
4	> 50.0 cu/ft

Underground Storage Risk and Integrity Management Plan

1. Downhole Safety Valve (DHSV) Leak-by Testing: McDonald Island

OPERATING PROCEDURES MCDONALD ISLAND STATION	SECTION 20	PG&E Gas System Operations SHEET 152 of 245 SHEETS	DRAWING NUMBER 0800662	REV. 0

APPROVED BY		REV	DATE	DESCRIPTION	GM	DWN	CHKD	SUPV	APVD
LDK7	AAR3	0	3/17/2016	Issued for use	31103200	TFM0	A3BZ/BKZ1		G1CC/PXT6

1. *Downhole Safety Valve (DHSV) Test*

1.1. *Introduction*

This procedure describes an annual test for wells in service (i.e., fully pressurized).

This procedure applies to all Gas personnel whose work includes field testing valves.

1.2. *SAFETY*

Working outdoors on Gas equipment may result in exposure to environmental hazards, including heat, cold, and inclement weather.

Exposure and reaction to stings or bites from bees, ticks, snakes, and other wildlife also may occur when implementing this procedure.

Slips, trips, and falls and associated cuts, bruises, sprains, and worse can occur when walking on steep, unstable, uneven, slippery, or wet surfaces.

To minimize disturbance, a buffer of 15-30 feet is required if nesting birds are discovered.

2. *Testing Procedure*

2.1. *BEFORE YOU START*

a. Schedule the job with Gas Operations.

b. If necessary, request proper clearance to remove well from service.

c. Gather all appropriate personal protective equipment (PPE) per the Gas Operations Matrix.

d. Gather the following:

- Calibrated gauges
- Calibrated volume measurement and appropriate sized and pressure rated hose
- Job Safety Site Analysis (JSSA)
- McDonald Island DHSV Test Form

2.2. PERFORMING THE HYDRAULIC CONTROL LINE LEAK TEST

a. **CHECK** with Operations and inform the operator of the testing.

b. **RECORD** the initial hydraulic control line shut-in pressure on the McDonald Island DHSV Test Form.

c. **CLOSE** the main hydraulic supply valve (V-H-6 at TCS or V-H-8 at WSS) to "lock-in" the hydraulic pressure.

d. **RECORD** at 5 and 10 minutes on the test form.

2.3. HYDRAULIC CONTROL LINE BUILDUP TEST

a. **CONNECT** the bleed manifold to the hydraulic supply/bleed valve.

b. **OPEN** the bleed valve on manifold.

c. **DRAIN** all fluid from the hydraulic control line into a 5-gallon bucket or other suitable container.

d. Wait 15 minutes to allow the control line to completely bleed.

e. **RECORD** the following on the test form:

- The hydraulic control line "bled to" pressure.
- Y/N for any presence of gas in the hydraulic control line.
- The amount of the fluid, in ounces, recovered in the container.

f. **CLOSE** the bleed valve on the manifold.

g. **RECORD** the pressure buildup in the hydraulic control line at 5, 10, 15, 30, and 45 minutes as on the test form.

2.4. SETUP ACTIONS

f. Set up to vent the tubing and casing well runs to atmosphere.

   i. Wellhead

      1. **CLOSE** Casing Wing Valve V-12 and the Master Gate Valve V-13.

      2. **CHECK OPEN** Casing Wing Pressure Tap V-16 and Tubing Sand Inspection V-17.

   ii. Platform

      1. **CHECK CLOSED** Tubing Header Block V-1.

      2. **CLOSE** Casing Header Block V-2 and Main Methanol Tap V-M-13.

      3. **CHECK OPEN**:

         - Tubing Riser V-7
         - Casing Riser V-8
         - Cross Over Valve V-9
         - Tubing Control Valve FV-T
         - Casing Control Valve FV-C.

      4. **OPEN** 1" Blow Down V-19 to Vent Well Run to 0 psig.

      5. **OPEN** V-18.

      6. **CLOSE** V-19.

      7. If necessary, double block and bleed meter run.

g. Setup wellhead for testing tubing and casing leak rates.

   i. **CHECK CLOSED** Tubing UHSV V-11 and Casing UHSV V-10.

   ii. **INSTALL** pressure gauge(s) to obtain both tubing and casing shut-in pressures.

   iii. **OPEN** Master Gate V-13.

2.5. TUBING LEAK TEST

h. **RECORD** the tubing shut-in pressure in the test form.

> **CAUTION**
>
> **IF** the tubing fails to blowdown to 500 psig below the shut-in pressure after 20 minutes,
>
> **AND** the Master Gate V-13 is fully **OPEN**,
>
> **THEN**:
> - **STOP** the test.
> - **NOTE** on the test form, "Tubing failed to blowdown."
> - **PROCEED** to Step 6, "Casing Leak Test."

i. **OPEN** the pressure tap on the wellhead to vent tubing pressure to 500 psig below the shut-in pressure.

j. IF necessary, **BLEED** the hydraulic control line pressure to 0 psig.

THEN **CLOSE** the bleed valve.

k. **RECORD** the following on the test form:

i. Tubing shut-in "bled to" pressure and hydraulic control line pressure.

ii. Pressure buildup in the tubing and hydraulic control line at 5, 10, 15, 30 and 45 minutes as per the DHSV test form.

2.6. CASING LEAK TEST

l. **RECORD** the casing shut-in pressure on the test form.

> **CAUTION**
>
> **IF** the casing fails to blowdown to 500 psig below the shut-in pressure after 30 minutes,
>
> **AND** the Casing Wind Pressure Tap V-16 is fully **OPEN**,
>
> **THEN**:
> - **STOP** the test.
> - **NOTE** on the test form, "Casing failed to blowdown."
> - **PROCEED** to Step 7, "Returning to Normal Status."

m. **OPEN** the pressure tap on the wellhead to vent the casing pressure to 500 psig below the shut-in pressure.

n. IF necessary, **BLEED** hydraulic control line pressure to 0 psig,

THEN **CLOSE** the bleed valve.

o. **RECORD** the following on the test form:

   i. Casing shut-in "bled to" pressure

   ii. Hydraulic control line pressure

   iii. Pressure buildup in the casing and hydraulic control line at 5, 10, 15, 30, and 45 minutes.

2.7. RETURNING WELL TO NORMAL STATUS

p. Unless directed otherwise by Operations, return the well to normal status.

   i. Wellhead

      1. **CHECK CLOSED** the main hydraulic supply valve.

      2. **CLOSE** Master Gate V-13.

      3. **CHECK CLOSED** Casing Wing Valve V-12.

   ii. Platform

      1. **PURGE** the well run as necessary.

      2. Slowly **OPEN** Casing Header Block Valve V-2.

      3. Fully **RE-PRESSURIZE** both tubing and casing well runs up to the tubing UHSV V-11 and the casing UHSV V-10.

      4. **OPEN** the Main Methanol Tap V-M-13.

      5. **RESET** and **OPEN** tubing UHSV V-11 and the casing UHSV V-10.

CAUTION

IF differential between tubing and casing shut-in pressures and field pressure is below 100 psig,

THEN proceed to Step iii Wellhead, 3 ("OPEN the main hydraulic supply valve to open the DHSV(s).") below.

IF differential between tubing and/or casing shut-in pressures and field pressure is above 100 psig,

THEN equalize the pressure above the DHSV(s) prior to opening.

iii. Wellhead

1. **OPEN** Master Gate V-13 to re-pressurize the tubing.
2. **OPEN** Casing Wing Valve V-12 to re-pressurize the casing.
3. **OPEN** the main hydraulic supply valve to open the DHSV(s).
4. **VERIFY** the hydraulic control line pressure is equal to the hydraulic platform pump pressure or approximately 4000 psig.
5. **RETURN** the well to normal when the test is complete

2.8. END OF TEST

q. **NOTIFY** Operations on completion of testing.

r. Immediately **REPORT** any abnormal issues to the Operations supervisor.

s. Ensure the test form is filled out completely, including the tester's LAN ID, DATE, and TIME.

t. **SCAN AND SECURELY FILE** a local hard copy of each data form.

u. **EMAIL** scanned copies to the Operations supervisor and Reservoir Engineering (gasopsstorageassetmanagementreservoir@pge.com).

2. Downhole Safety Valve (DHSV) Leak-by Testing: McDonald Island – Wells Out of Service

Purpose: This procedure describes test for wells in service (i.e., fully pressurized).

This procedure applies to all Gas personnel whose work includes field testing valves.

TEST PROGRAM FOR WELLS OUT OF SERVICE (i.e. Station Outage)

TEST FREQUENCY- Annually

Record all data on the DHSV test form provided.

1. If necessary, contact the Operations department for proper clearance to test well.

2. Setup wellhead for testing of the Hydraulic Control Line:

  a. **CHECK CLOSED** (Uphole Safety Valves), Tubing UHSV V-11 and Casing UHSV V-10.

  b. **OPEN** Mastergate V-13 and Casing Wing Pressure Tap V-16.

  c. **INSTALL** pressure gauge(s) to obtain both Tubing and Casing Shut-in pressures.

NOTE: If differential between Tubing and/or Casing Shut-in pressures and Field pressure is below **100 PSIG**, proceed to Step 2d.

If differential between Tubing and/or Casing Shut-in pressures and Field pressure is above **100 PSIG**, it will be necessary to equalize pressure above the DHSV(s) prior to opening.

  d. **CLOSE** the main Hydraulic Supply Valve (V-H-6 at TCS or V-H-8 at WSS).

  e. **CONNECT** Hydraulic pump to the Hydraulic Supply/Bleed Valve.

  f. **PRESSURIZE** the Hydraulic Control Line to **4000 PSIG** to open DHSV(s).

3. Hydraulic Control Line Leak Test:

  a. **CLOSE** the Hydraulic Supply/Bleed Valve to **"LOCK-IN"** Hydraulic pressure.

  b. **RECORD** initial Hydraulic Control Line Shut-in pressure.

  c. **RECORD** at **5 and 10 minutes** as per DHSV test form.

  d. **DISCONNECT** Hydraulic pump.

4. Hydraulic Control Line Buildup Test:

a. **CONNECT** Bleed Manifold to the Hydraulic Supply/Bleed Valve.

b. **OPEN** bleed valve on manifold and drain all fluid from the Hydraulic Control Line into a 5-gallon bucket or other suitable container. Wait **15-30 minutes** to allow Control Line to bleed completely.

c. **RECORD** Hydraulic Control Line "BLED TO" pressure.

d. **RECORD** Y/N for any presence of gas in the Hydraulic Control Line.

e. **RECORD** in ounces the amount of fluid returned to surface.

f. **CLOSE** bleed valve on manifold.

g. **RECORD** pressure buildup in the Hydraulic Control Line at **5, 10, 15, 30 and 45 minutes** as per DHSV test form.

5. Setup wellhead for testing Tubing and Casing leak rates:

a. **CHECK CLOSED** Tubing UHSV V-11 and Casing UHSV V-10.

b. **CHECK OPEN** Mastergate V-13 and Casing Wing Pressure Tap V-16.

c. **CHECK CLOSED** Casing Wing V-12.

6. Tubing Leak Test:

a. **RECORD** Tubing Shut-in pressure.

b. **OPEN** pressure tap on the wellhead to vent Tubing pressure to **500 PSIG** below Shut-in pressure.

NOTE: If Tubing fails to blowdown **500 PSIG** below Shut-in pressure after **20 minutes** and Mastergate V-13 is fully open, stop test and note on DHSV test form "Tubing failed to blowdown" and proceed to Step 7.

c. If necessary, **BLEED** Hydraulic Control Line pressure to **0 PSIG**, then close bleed valve.

d. **RECORD** Tubing Shut-in "BLED TO" pressure and Hydraulic Control Line pressure.

e. **RECORD** pressure buildup in the Tubing and Hydraulic Control Line at **5, 10, 15, 30 and 45 minutes** as per DHSV test form.

7. Casing Leak Test:

a. **RECORD** Casing Shut-in pressure.

b. **OPEN** pressure tap on the wellhead to vent Casing pressure to **500 PSIG** below Shut-in pressure.

NOTE: If Casing fails to blowdown **500 PSIG** below Shut-in pressure after **30 minutes** and Casing Wing Pressure Tap V-16 is fully open, stop test and note on DHSV test form "Casing failed to blowdown" and proceed to Step 8.

c. If necessary, **BLEED** Hydraulic Control Line pressure to **0 PSIG**, then close bleed valve.

d. **RECORD** Casing Shut-in "BLED TO" pressure and Hydraulic Control Line pressure.

e. **RECORD** pressure buildup in the Casing and Hydraulic Control Line at **5, 10, 15, 30 and 45 minutes** as per DHSV test form.

8. Return well to "AS FOUND" status unless directed by Operations to do otherwise:

a. **CLOSE** Mastergate V-13 and Casing Wing Pressure Tap V-16.

b. **OPEN** the main Hydraulic Supply Valve at wellhead.

9. **NOTIFY** Operations that testing has been completed and **REPORT** any serious issues to the Operations Supervisor immediately. **Ensure** the DHSV test form is filled out completely, including tester's LAN ID and DATE. **REMIT** to the Operations Supervisor.

3. Downhole Safety Valve (DHSV) Leak-by Testing: Los Medanos

OPERATING PROCEDURES LOS MEDANOS STATION SECTION 37	PG&E Gas System Operations SHEET 161 of 245 SHEETS	DRAWING NUMBER 0800608	REV. 0

APPROVED BY		REV	DATE	DESCRIPTION	GM	DWN	CHKD	SUPV	APVD
LDK7	AAR3	0	3/17/2016 updated 9/26/17	Issued for use	31103200	TFM0	A3BZ/JCC4	AOO2	DDT8/BKZ1

1. ***Downhole Safety Valve (DHSV) Test***

1.1. ***Introduction***

This procedure describes test for wells in service (i.e., fully pressurized). This procedure applies to all Gas personnel whose work includes field testing valves.

(California Code of Regulations Title 14, Division 2, Chapter 4, Subchapter 1, Section 1724.4(d))

This procedure describes an annual test for wells in service (i.e., fully pressurized and DHSVs OPEN).

This procedure applies to all Gas personnel whose work includes field testing valves.

2. ***SAFETY***

Working outdoors on Gas equipment may result in exposure to environmental hazards, including heat, cold, and inclement weather.

Exposure and reaction to stings or bites from bees, ticks, snakes, and other wildlife also may occur when implementing this procedure.

Slips, trips, and falls and associated cuts, bruises, sprains, and worse can occur when walking on steep, unstable, uneven, slippery, or wet surfaces.

To minimize disturbance, a buffer of 15-30 feet is required if nesting birds are discovered.

3. *Testing Procedure*

3.1. *BEFORE YOU START*

a. Schedule the job with Gas Operations.

b. If necessary, request proper clearance to remove well from service.

c. Gas Pipeline Operations and Maintenance (GPOM) must notify Reservoir Engineering at least 96 hours before testing.

d. Gather all appropriate personal protective equipment (PPE) per the Gas Operations Matrix.

e. Gather the following:

- Calibrated gauges
- Job Safety Site Analysis (JSSA)
- Los Medanos DHSV Test Form

3.2. *PERFORMING THE HYDRAULIC CONTROL LINE LEAK TEST*

a. **CHECK** with Operations and inform the operator of the testing.

b. **RECOR**D the initial hydraulic control line shut-in pressure.

c. **CLOSE** the main hydraulic supply valve to "lock-in" the hydraulic pressure.

d. **RECORD** at 5 and 10 minutes on the Los Medanos DHSV Test Form.

3.3. *HYDRAULIC CONTROL LINE BUILDUP TEST*

a. **CONNECT** the bleed manifold to the hydraulic supply/bleed valve.

b. **OPEN** the bleed valve on manifold.

c. **DRAIN** all fluid from the hydraulic control line into a 5-gallon bucket or other suitable container.

d. Wait 15 minutes to allow the control line to completely bleed.

e. **RECORD** the following on the test form:

- The hydraulic control line "bled to" pressure.
- Y/N for any presence of gas in the hydraulic control line.

- The amount of the fluid recovered in the container in ounces).

f. **CLOSE** the bleed valve on the manifold**.**

g. **RECORD** the pressure buildup in the hydraulic control line at 5, 10, 15, 30, and 45 minutes as on the test form.

3.4. <u>SETUP ACTIONS</u>

a. Set up to vent the tubing and casing well runs to atmosphere.

b. **INSTALL** pressure gages on top of tree and casing pressure tap.

c. **RECORD** the pressures on the test form.

i. **CLOSE** V-9.

ii. **OPEN** casing and tubing UHSVs.

iii. Note the tubing and casing pressure.

iv. **OPEN** several vents to blowdown pressure to 500 psig below pressure noted in the previous step (4.a.iii).

v. **CLOSE** the vents.

d. Setup the wellhead for testing tubing and casing leak rates.

vi. **CLOSE** both UHSVs.

vii. **RECORD** the tubing and casing "bled to" pressures on the test form.

viii. **RECORD** the tubing and casing pressure buildup at 5, 10, 15, 30 and 45 minute intervals on the test form.

ix. IF pressures does not blow down in the previous section,

THEN:

1. **ISOLATE** the tubing and casing.
2. **VERIFY** which DHSV is not fully CLOSED.
3. Note on the test form.
4. Leave isolated.
5. Finish testing the DHSV(s) that will CLOSE.

3.5. RETURNING WELL TO NORMAL STATUS

a. **CHECK CLOSED** the main hydraulic supply valve.

b. **CHECK CLOSE** V-9.

c. **OPEN** both UHSVs.

d. **OPEN** V-1 and V- 5 as necessary to route gas back to wellhead to equalize safety valves.

e. **SLOWLY OPEN** V-9 to equalize the safety valves.

f. IF differential between tubing and casing surface pressures and field pressure is below 100 PSIG,

THEN proceed to step 5.h below.

g. IF differential between tubing and/or casing surface pressures and field pressure is above 100 PSIG,

THEN equalize the pressure across the DHSV(s) prior to opening.

h. **OPEN** the main hydraulic supply valve to open the DHSV(s).

i. **VERIFY** hydraulic control line pressure is equal to the hydraulic supply pressure or approximately 4200 PSIG.

3.6. END OF TEST

a. **NOTIFY** Operations on completion of testing.

b. **REPORT** any abnormal issues to the Operations supervisor.

c. Ensure the Los Medanos DHSV Test Form is filled out completely, including the reader's LAN ID and DATE.

d. **SCAN AND SECURELY FILE** a local hard copy of each data form.

e. **EMAIL** scanned copies to the Operations supervisor and Reservoir Engineering (gasopsstorageassetmanagementreservoir@pge.com).

Underground Storage Risk and Integrity Management Plan

Appendix R-FXN, Practice 14A - Downhole Safety Valve (DHSV) & Uphole Safety Valve(UHSV) Function Testing McDonald Island Station

DOWNHOLE & UPHOLE SAFETY VALVE FUNCTION TESTING

Purpose: Provide procedures for the function testing of downhole safety valves (DHSV) and uphole safety valves (UHSV) at McDonald Island Storage Facility.

What: Wells equipped with a “downhole” safety valve (DHSV) or surface controlled subsurface safety valves (SCSSV) typically have valves installed 250 feet below ground level to provide emergency shutdown in the event the storage well cannot be isolated by the wellhead master valve. DHSV valves are surface controlled hydraulically operated and are “fail safe” type valves (hydraulic control system pressure keeps the valves open, and the valves close on loss of hydraulic control system pressure).

“Uphole” safety valves (UHSV) or emergency shutdown valves (ESD) are installed on the transmission piping to isolate the transmission pipeline from abnormal low pressure downstream of the valve, including loss of containment of a storage well or the piping systems. UHSV are typically installed near the connection of the transmission piping and storage wellhead.

This practice uses API Recommended Practice 14B Sixth Edition, September 2015 as guidance in developing the test procedures.

Frequency: At least every six months

Notification & Records: The following is required:

1) 48 hours advanced noticed shall be provided to DOGGRs Division Office by GPOM personnel charged with executing.

2) A paper copy of testing results shall be scanned and local hard copy of each data form shall be securely filed. The DOGGR representative, if present to witness the test, shall sign off on the results recorded.

3) Within 24hours of test being completed a scanned copy shall be provided to Reservoir Engineering (gasopsstorageassetmanagementreservoir@pge.com).

Procedure:

1. Description of the Emergency Shutdown System

Station Emergency Shutdown 'ESD' is a safety system that will shutdown the station during an emergency. Upon initiation of an 'ESD' an alarm will occur in Cimplicity and will sound in the control room and the control room annunciator panel will illuminate an 'ESD' alarm window.

To prevent catastrophic damage and injury to personnel, all gas flow to and from the station will be blocked and all station processing piping will be de-pressurized. The ESD system can be initiated either automatically or manually.

1.1. ESD Shutdown Initiation

When an 'ESD' is initiated the following will occur:

1. The station goes into a 'LOCKOUT' state.
2. Solenoid valves, SOV-A-90 and SOV-A-91, de-energize shutting down the instrument air system to the gathering platform causing all well safety valves [Uphole Safety valves (UHSVs) and Downhole Safety valves (DHSVs)] and well flow control valves to close.
3. Casing Header Emergency block valves, V-45 and V-46 close.
4. Tubing Header Emergency block valves, V-51 and V-55 close.
5. Station Emergency block valves, V-56, V-57 and V-58 close.
6. Station Emergency Blowdown valves, V- M and V-71 open and all processing gas is vented to the blowdown stack.
7. Reboiler #1 and #2 burner controls, glycol pumps and glycol cooler fans shutdown.
8. The Thermal Oxidizer is shutdown.
9. Fuel gas and Generator fuel gas is blocked at each rack with closure of Security valves, PCV-G-13 and PCV-G-49.
10. The Hydraulic Supply System is shutdown.
11. All motors 10 HP and greater on the MCC bus are shut down.

NOTE: Station Instrument and Utility Air Compressors, AK-1, AK-2 and AK-3 will continue to run when an 'ESD' occurs.

1.3. Manual Shutdown Initiation

Manual initiation occurs when Turner cut station personnel operate one of the thirteen 'ESD' push buttons at any of the following locations:

- East end stairway, on the gathering platform.
- Five (5) ladder locations on the gathering platform.
- Center near catwalk on the processing platform.
- North side stairway on the processing platform.
- South side stairway on the processing platform.
- West end stairway on the control platform.
- Station Main Gate
- Turner Cut Control Room Board
- Glycol/Methanol Storage area firewall

2. Functional Test UHSVs and DHSVs

2.1. Reset and check Open UHSVs and DHSVs on all in-service wells

- **Record** wells that are out of service or have known safety valve problems
- **CLOSE** V-63 to prevent the unnecessary blowdown of natural gas to atmosphere.
- **Manually Initiate** an ESD pushbutton
- **Walk Down** all active wells - all UHSVs and DHSVs should have closed
- **Record** DHSV and UHSV status at each in-service well
- **CLOSE** the casing wing UHSV air supply stop valve, V-A-(Well #) 14 at each well
- **OPEN** the casing wing UHSV vent valve, V-A- (Well #) 15 at each well
- **CLOSE** the tubing UHSV air supply stop valve, V-A-(Well #) 12 at each well
- **OPEN** the tubing UHSV vent valve, V-A-(Well #) 13 at each well
- **CLOSE** Hydraulic supply valve, V-H-(well#) 6 at each well to isolate from the platform hydraulic supply.

2.3. To RESET the station from an 'ESD':

- **ENSURE** the Casing and Tubing Header Emergency Block Valve (V-45, V-46, V-51 and V-55) 'OPEN/CLOSE' Switches on the Control Room Board are in the 'CLOSE' position
- **ENSURE** the Station Emergency Block Valve (V-56, V-57 and V-58) 'OPEN/CLOSE' Switches on the Control Room Board are in the 'CLOSE' position.
- **ENSURE** Station Blowdown Valve, V-M 'OPEN/CLOSE' Switch on the Control Room Board is in the 'CLOSE' position.
- **ENSURE** Station Blowdown Valve, V-71 'OPEN/CLOSE' Switch on the Control Room Board is in the 'CLOSE' position.
- **DEPRESS** the Station 'ESD RESET' button on the Control Room Board.
- **NOTE:** If all the conditions that initiated Station 'ESD' have been safely corrected or isolated, the control room annunciator panel 'ESD' alarm should clear.
- **DEPRESS** the Station 'LOCKOUT RESET' button on the Control Room Board.
- **RESET** hydraulic pilot valve, R-A-128 (pull plunger) which will open R-H-98.
- **NOTE:** R-A-128 is located in the hydraulic cabinet.
- **OPEN** V-63 to restore ESD valve M function
- **NOTE:** The station has been reset from an 'ESD'. The duration and conditions that initiated the 'ESD' will determine if the piping needs to be purged prior to re-pressurizing the station.

2.4. To Test DHSV Local Operation

- **ENSURE** that the Gas Differential Pressure between the Storage field and the Wellhead is **less than 100 PSIG** before DHSVs are opened.
- **CAUTION:** Damage will occur to the DHSV if DHSVs are opened and Gas Differential Pressure between the Storage field and the Wellhead is greater than 100 psig. The Green light at the DHSV meter run 'OFF/AUTO' switches will be ON if the Gas Differential is less than 100 psig.
- **VERIFY** that the DHSV Hydraulic Supply Pressure Gauge at the Wellhead Control Rack is at **4000 PSIG.**
- **VERIFY** DHSV is **RESET** in CIMPLICITY on each well
- **RECORD** safety valve conditions at each well as test progresses
- **SLOWLY OPEN** Hydraulic Supply Valve V-H-(Well#)6 at each well to open DHSVs
- **VERIFY** DHSVs open by observing pressure gauge

- **To Test UHSV Local Operation**
- **CLOSE** the tubing UHSV vent valve, V-A-(Well #) 13.
- **OPEN** the tubing UHSV air supply stop valve, V-A-(Well #) 12.
- **OBSERVE** tubing UHSV opens
- **CLOSE** the casing wing UHSV vent valve, V-A- (Well #) 15
- **OPEN** the casing wing UHSV air supply stop valve, V-A-(Well #) 14.
- **OBSERVE** casing wing UHSV opens

Underground Storage Risk and Integrity Management Plan

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

CASING INSPECTION LOGGING AND DATA ASSESSMENTS

Purpose: Provide standards and procedures for casing inspection logging and data assessments.

What: The Casing Inspection Logging provides a holistic program to ensure compliance with the California State Division of Oil, Gas and Geothermal Resources (DOGGR) regulations (California Code of Regulations Title 14, Division 2, Chapter 4) for well casing integrity monitoring.

Why: Gas storage wells may be in service for 75 or more years. Therefore, it is prudent to design the wells to remain intact for that time period and to monitor and maintain the integrity to prevent well leakage. Methods utilized to assess and prevent future casing failures and gas releases include storage well logging.

Wells are logged to identify potential problems and may include the following types of logs (type of log/survey identified in parenthesis.

- Reductions to casing wall thickness (Casing Inspection Tools)
- Caliper
- Identification of gas presence behind the casing (Gamma Ray Neutron – GRN)
- Presence of a corrosion cell (Casing Protection Profile – CPP)
- Temperature Logs
- Noise Logs
- Downhole video cameras and/or downhole video side view cameras
- E-Log-I Surveys

In addition, for future new storage wells certain logs shall be considered to be run during drilling and completion. The list of logs to consider, principle (how the log works), and the identification (purpose of the log) are presented in Appendix A.

Underground Storage Risk and Integrity Management Plan

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

- Open Hole Logs
    - Caliper
    - Density w/Pe (Litho-Density)
    - Compensated Neutron Log (CNL)
    - Spontaneous Potential (SP)
    - Gamma Ray (GR)
    - Resistivity Logs (Dual-Induction or Array Induction)
    - Microlog (ML)
- Cased Hole Logs
    - Casing Inspection Tools (i.e., Vertilog, MicroVertilog, High-Resolution Vertilog, Caliper, and Ultrasonic inspections)
    - Cement Bond Log/Cement Mapping Tool with Gamma Ray and Casing Collar Locator or Segmented Bond Tool with Gamma Ray and Casing Collar Locator
    - Base line TDT/PDK with Gamma Ray and Casing Collar Locator or Gamma Ray Neutron with Casing Collar Locator

Casing Inspection Tools and CPP

Casing Inspection Tools and CPP are beneficial to get a baseline on the condition of the casing and the following criteria summary should be utilized (see Appendix A for further details).

- Run baseline logs (Casing Inspection tool and/or GRN) on every well when the tubulars are removed.
- Follow-up casing inspections are required on casing completed wells to assess the rate of change in pipe corrosion at time intervals to be determined by the condition of the pipe.
- Follow-up casing inspections on tubing and packer completed wells are required when tubing is pulled for other remedial work and with consideration of the time interval between the remedial work and the last casing inspection tool run.

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

- Noise and Temperature logs (annually) and GRN logs (periodic) will be run on tubing and packer completed wells that do not have baseline casing inspections to identify changes in gas accumulation behind pipe and review
- Coordination and communication with the Operations department to verify that wells are protected by a cathodic protection system.

Periodically, E-Log-I surveys to be conducted by Corrosion department in an attempt to ensure that sufficient bond current is being applied to each well's production casing string.

Casing Inspection Logging Using Electromagnetic Logs: This tool (Electromagnetic corrosion and protection evaluation log) measures the casing potential and resistance evaluation, thereby determining the extent of the corrosion. The Electromagnetic log used by the Reservoir Engineering department is the Verti-log. "The Verti-log is a casing inspection service which is now available to the oil and gas industry to determine the condition of the casing in existing wells. It is a quantitative measurement of corrosive damage, indicating if the metal loss is internal or external and if it is isolated or circumferential", (onepetro.org).

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

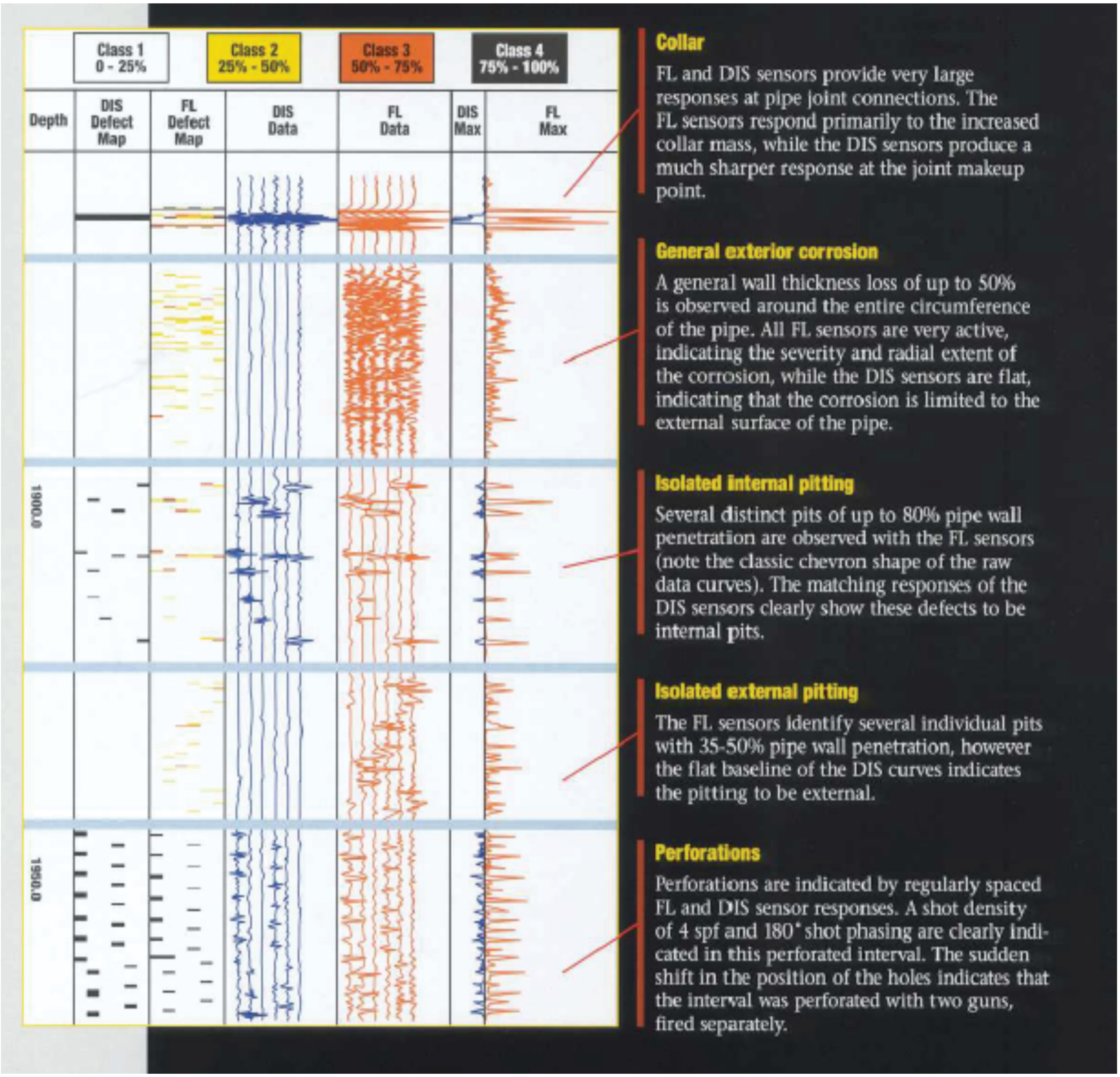


Figure S-1. Detailed Verti-log courtesy of Baker-Hughes.

Figure S-2, Shows the verti-log of well TC-17N during the 2014 Rework program courtesy, Baker Hughes.

97	4025.71	4068.04	42.33	Class 1	-	-	-
98	4068.04	4108.20	40.16	Class 1	-	-	-
99	4108.20	4150.37	42.17	Class 1	-	-	-
100	4150.37	4191.30	40.93	Class 1	-	-	-
101	4191.30	4231.99	40.69	Class 1	-	-	-
102	4231.99	4274.78	42.79	Class 1	-	-	-
103	4274.78	4316.70	41.92	Class 1	-	-	-
104	4316.70	4358.62	41.92	Class 1	-	-	-
105	4358.62	4399.68	41.06	Class 1	-	-	-
106	4399.68	4440.89	41.21	Class 1	-	-	-
107	4440.89	4482.02	41.13	Class 1	-	-	-
108	4482.02	4524.22	42.20	Class 1	-	-	-
109	4524.22	4565.84	41.62	Class 1	-	-	-
110	4565.84	4607.83	41.99	Class 1	-	-	-
111	4607.83	4650.42	42.59	Class 1	-	-	-
112	4650.42	4691.58	41.16	Class 1	-	-	-
113	4691.58	4736.63	45.05	Class 1	-	-	-
114	4736.63	4781.57	44.94	Class 1	-	-	-
115	4781.57	4826.04	44.47	Class 1	-	-	-
116	4826.04	4870.57	44.53	Class 1	-	-	-
117	4870.57	4913.80	43.23	Class 1	-	-	-
118	4913.80	4959.82	46.02	Class 1	-	-	-
119	4959.82	5004.14	44.32	Class 1	-	-	-

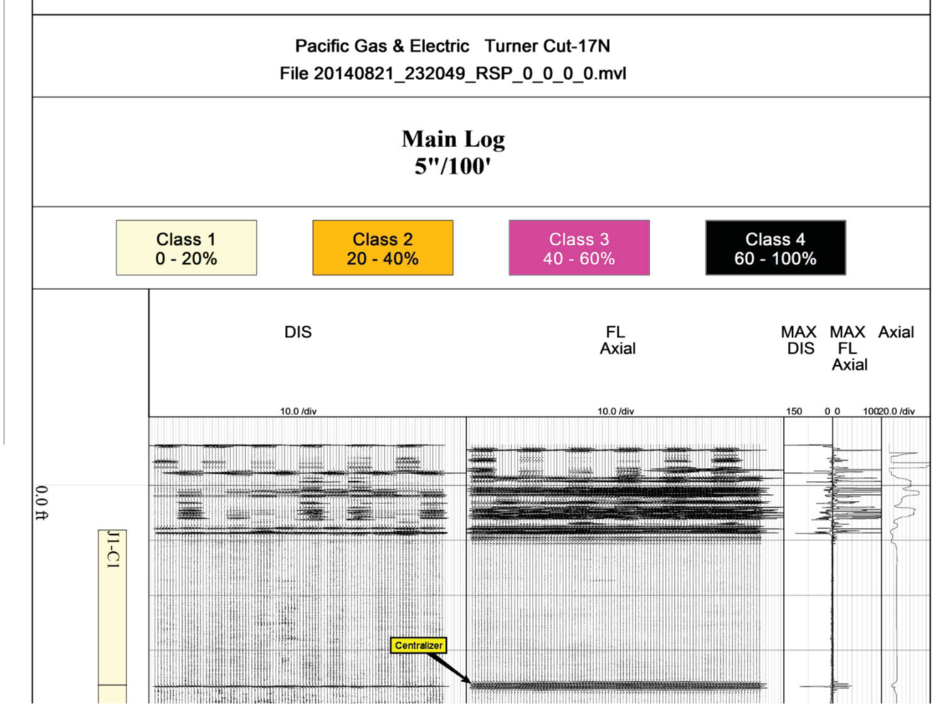


Figure S-2. TC-17 2014 Verti-log.

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

Verti-log Class/color identification: The following class/color identification is based on the Baker-Hughes Verti-log correlation analysis whose penetration involves the acquired flux change, discriminator sensor management and the computed results.

- Class 1: Seen in white, includes 0-20% penetration
- Class 2: Seen in orange, includes a 20-40% penetration rate
- Class 3: Seen in pink, includes a 40-60% penetration
- Class 4: Seen in black, includes a 60-100% penetration.

When: Noise and Temperature surveying is completed annually, other logging is completed to establish a baseline, per an assessment logging plan and reoccurring frequency and more frequent if determined necessary. Need for specialized or additional logging should be considered when under a standard clearance and during well rework operations.

Who:

- Underground Gas Storage (UGS) Operations initiates clearances
- Contractor performs testing services.
- Reservoir Engineering (RE) supervises on-site surveys
- RE reviews survey data for reasonableness and completeness.
- RE evaluates survey data and recommends course of actions, if any.

Evaluation:

1. The survey logs are evaluated to determine if any apparent anomalies exist.
2. Review logs when they arrive in office. Check for large defects that should be addressed immediately, confirm log header information and casing information is correct, confirm that all logs run have been received.
3. Use previously run log as base line and compare and correlate the apparent anomalies to identify potential casing integrity issues.

Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments

4. Any anomalies or trending shall be reported immediately to the director, manager, supervisor and engineer. Appendix B contains additional investigations to consider, Appendix C lists definitions for metal loss and assessment of apparent growth, and Appendix D shows a remedial decision tree that should be used in aiding to develop a plan of action to assess the anomalies. Based on the plan of action results, remedial action will be determined and the well will remain shut-in until repairs are completed or the well will be placed back in service. All plan of action documentation will be kept in the GSDB/well file.

5. Prepare a summary report (one report per field) documenting results.

6. Select wells for next year's logging program based on a specific recommendation that had been made at the time of the previous review, or according to the "Casing Inspection Survey Frequency Decision Tree".

7. Reservoir Engineering, based on the above, will prioritize remedial work and input in the GSDB and S1 and S2 processes.

8. Communicate results to Operations & Maintenance and Reservoir Engineering departments.

Underground Storage Risk and Integrity Management Plan

Appendix T, Practice 16 - Annual Temperature / Noise Logging and Data Review

Page 1 of 6

ANNUAL TEMPERATURE / NOISE LOGGING AND DATA REVIEW

Purpose: Provide standards and procedures for annual temperature / noise logging and data review.

Detailed Procedure: Utility Procedure: TD-4870P-01 Gas Well Wireline Procedure (Replaced TD-4550P-20)

What: This is to comply with the California State Division of Oil, Gas and Geothermal Resources (DOGGR) regulations (California Code of Regulations Title 14, Division 2, Chapter 4) for annual well casing integrity survey. A temperature survey is not only the oldest of the production surveying instruments, it is also unique in its logging, it is one of the logs that is least likely to mislead its interpreter except he/she is not thoroughly trained to its interpretation. Platinum is the preferred sensor in the temp log because the resistivity is stable and increases with temperature over a wide range.

The survey is usually conducted on an Analog/digital truck contracted by PG&E which transmits a count per minute which is converted to voltage by a counting circle and recorded on a pen-and-ink strip chart as a temperature or gradient trace. Figure T-1 (A&B) below shows an over view of the temp/acoustic tool.

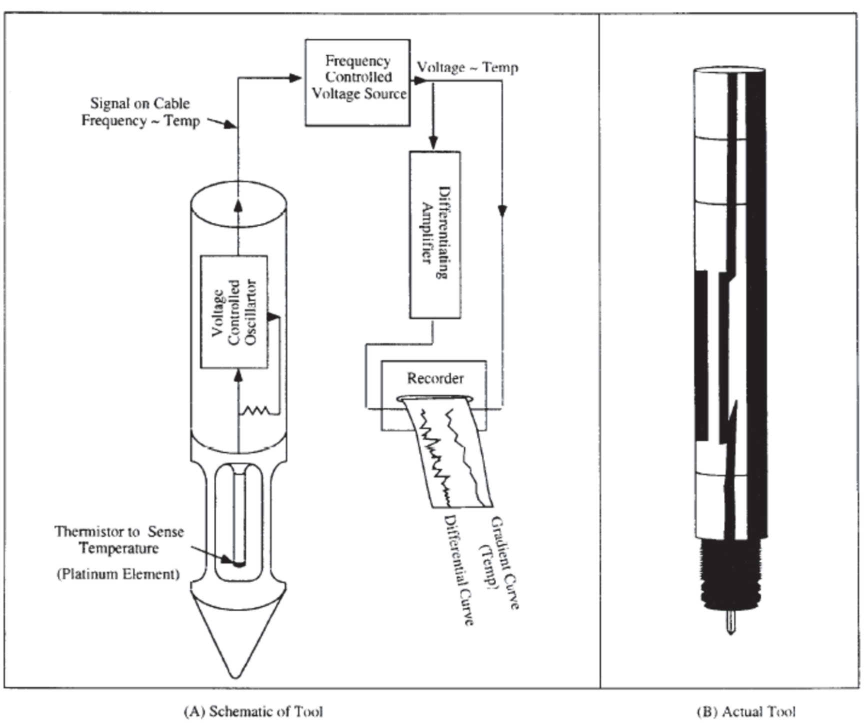


Figure T-1. Temp/Acoustic Tool.

Underground Storage Risk and Integrity Management Plan

A noise logging tool is a microphone designed to handle wellbore conditions and measures sound at different positions in the borehole. Figure T-2 (A&B), Shows a schematic of an acoustic tool and piezoelectric crystals which converts the oscillating pressure associated with sound transmission within the wellbore to an oscillating voltage that input directly to an amplifier-cable driver combination.

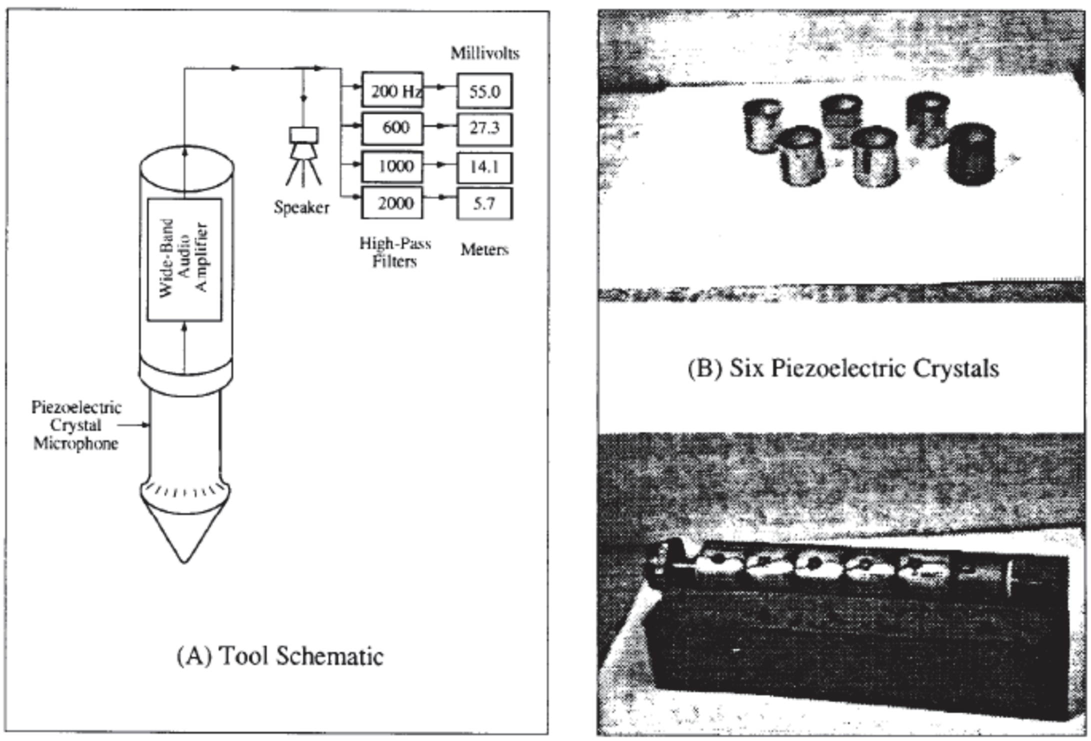


Figure T-2. Acoustic/Noise Tool Schematic and Piezoelectric Crystals

Why: The annual testing is conducted to comply with the State DOGGR regulation requirements that a mechanical integrity test (MIT) must be performed on all injection wells to ensure the injected fluid is confined to the approved zone or zones.

When: Test annually under a standard clearance: normally between April and October of the year.

Who:

- Underground Gas Storage (UGS) Operations initiates clearances
- Contractor performs testing services.
- Reservoir Engineering (RE) supervises on-site surveys
- RE reviews survey data for reasonableness and completeness.
- RE evaluates survey data and recommends course of actions, if any.

Logging Procedure: Temperature survey sensors are located near the bottom end of the tool as much as possible. “This allows the sensor to contact fluids that has not been mixed vertically by the passage of the tool and wireline” (Tech-guide, ONLINE).

The temperature survey should start at least 100ft above the zone of interest to allow time for the moving tool to stabilize. Logging speed is included in the well specific program created by RE and considers recommendation from the logging vendor.

With the Acoustic/Noise logging, the most obvious procedural question is related to proper spacing between readings. The measured sound levels on a noise log are significant for two reasons:

- The level increase above ambient is obviously related to the severity of the problem.
- The level of sound on a noise/acoustic log is the best quality control index available in terms of analysis.

Underground Storage Risk and Integrity Management Plan

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4200	14.30	4.40	1.50	0.50
4400	14.20	4.40	1.50	0.50
4600	14.20	4.30	1.50	0.50
4800	14.40	4.20	1.50	0.50
4900	14.50	3.90	1.40	0.50
4925	14.70	3.70	1.40	0.50
4948	14.70	3.40	1.40	0.50

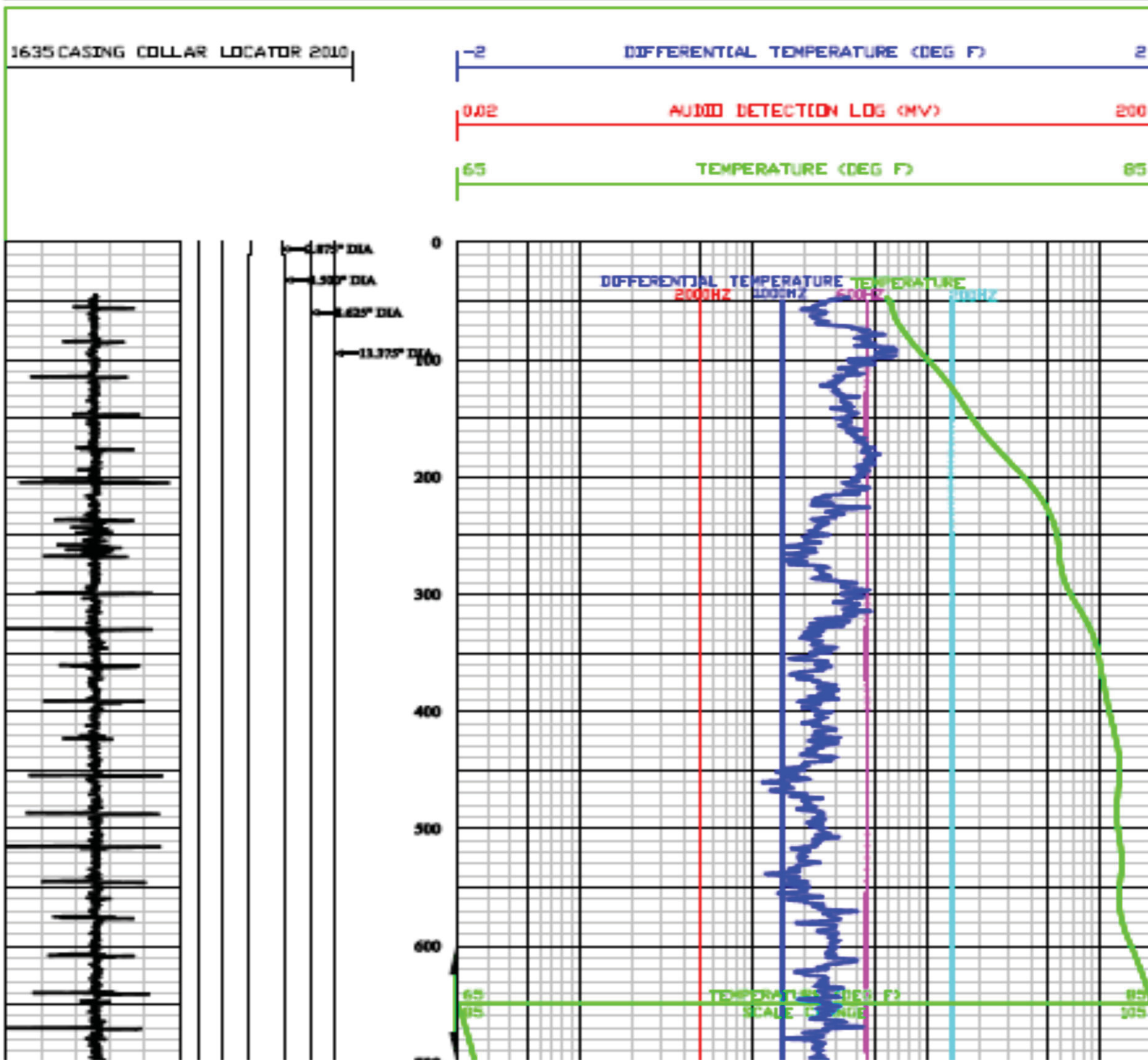


Figure T-3. Typical Noise/Temp Log Used by PG&E Operations.

As mentioned earlier, PG&E temp/noise survey is usually contracted out. Figure T-4. shows a temp/noise survey in progress on the Whiskey Slough plant station.

Figure T-4. Temp/Noise Survey Being Conducted.

Reservoir Engineer/Operator inspects the progress of the logging.

Evaluation:

1. The survey logs are evaluated to determine if any apparent anomalies exist.

2. Reservoir engineer documents review in the Wireline Database.

3. Compare the apparent anomalies to the previous year survey results to determine the severity of the apparent anomalies.

4. Correlate the apparent anomalies with the Gamma Ray Neutron logs and the Casing Inspection results to identify casing integrity issues.

5. Communicate the results to DOGGR and the Reservoir Engineering department within 30 days of running the log.

6. Reservoir Engineering, based on the above, will prioritize remedial work and input in the GSDB and S1 and S2 processes.

Underground Storage Risk and Integrity Management Plan

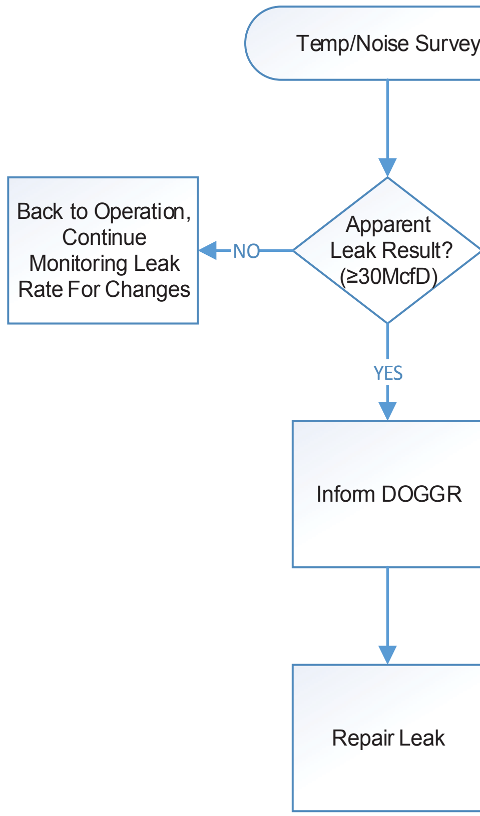


Figure T-5. Temp/Noise Survey Decision Tree.

Underground Storage Risk and Integrity Management Plan

Appendix U, Practice 17 - Gamma Ray Neutron Logging and Data Review

GAMMA RAY NEUTRON LOGGING AND DATA REVIEW

Purpose: Provide standards and procedures for gamma ray neutron logging and data review.

What: The GRN logging is supplemental to the T/N (Temperature/Noise) logging to ensure compliance with the California State Division of Oil, Gas and Geothermal Resources (DOGGR) regulations (California Code of Regulations Title 14, Division 2, Chapter 4) for annual well casing integrity monitoring. The GRN log can be run in air, oil, gas or mud filled open or cased holes. There are three basic neutron logging tools each consisting of a chemical neutron source.

- CNL: Compensated Neutron Log
- SNL: Sidewall Epithermal Neutron Log
- GRN: Gamma Ray Neutron Log

The gamma-ray neutron (GRN) logs are one of the three classes of the neutron logging tool. The GRN is sensitive to capturing gamma rays that are emitted due to the absorption of thermal neutrons by the nuclei in the rocks.

Why: The GRN logging is supplemental to the T/N logging to provide additional correlations in evaluating casing integrity, to improve well casing integrity and safety, reduce the risk of gas leakage and unsafe operations. Also, the GRNL is unaffected by fluids and measures both the lithology and natural radioactivity of the formation using a scintilometer (Geiger counter). GRNL can also be useful for the following:

- Determination of porosity / Lithology
- Delineation of porous formations
- Gas detection (with other logs)
- Estimation of shale content (w/ other logs)

When: Test periodically under a standard clearance.

Who:

- Underground Gas Storage (UGS) Operations initiates clearances
- Contractor performs testing services.
- Reservoir Engineering (RE) supervises on-site surveys
- RE reviews survey data for reasonableness and completeness.
- RE evaluates survey data and recommends course of actions, if any.

Principle of Operation:

- Neutrons emitted from radioactive source
- Collide and lose energy (Billiard ball effect)
- Primarily dependent on hydrogen concentration or index
- Detect either epithermal neutrons, thermal neutrons, capture gamma rays or combination
- Thus, measures the formations ability to attenuate the passage of neutrons

Underground Storage Risk and Integrity Management Plan

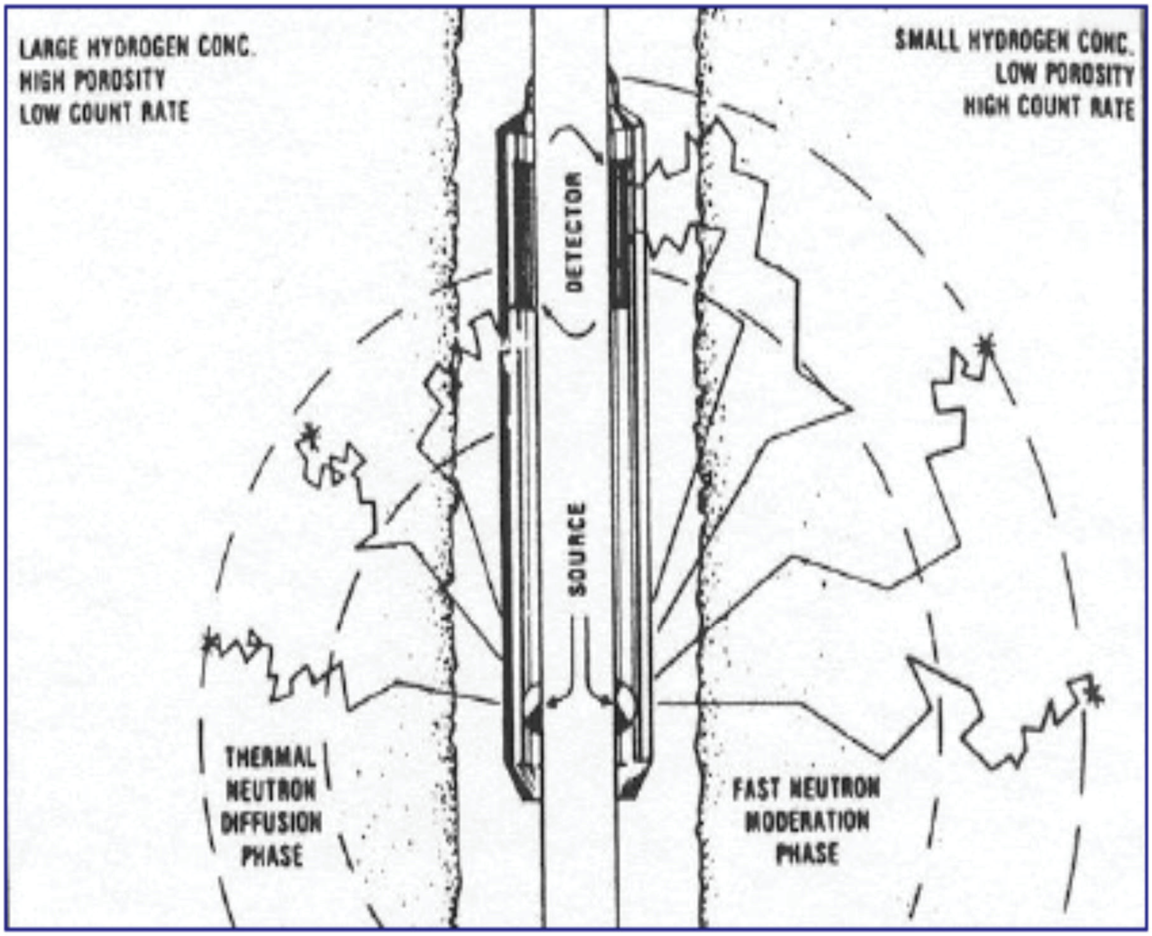


Figure U-1. Single Neutron Tool In A Bore-Hole.

Underground Storage Risk and Integrity Management Plan

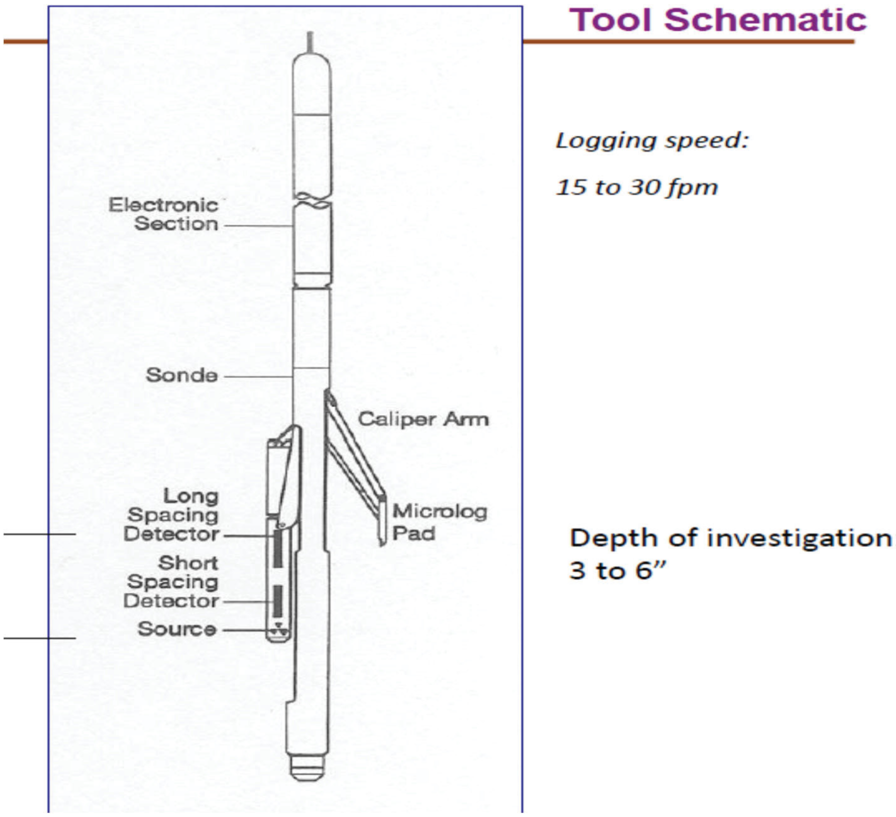


Figure U-2. Density Logging Tool Schematic.

Evaluation:

1. The survey logs are evaluated to determine if any apparent anomalies exist.

2. Use baseline GRN log if one has been established as base line and compare the apparent anomalies to determine the severity of the apparent anomalies and identify gas migration, if any.

3. Correlate the apparent anomalies with the T/N logs and the Casing Inspection results to identify casing integrity issues.

4. Communicate the results to the Reservoir Engineering department.

5. Reservoir Engineering, based on the above, will prioritize remedial work and input in the GSDB and S1 and S2 processes.

Underground Storage Risk and Integrity Management Plan

Appendix V, Practice 18 - Cement Bond Logging Survey

CEMENT BOND LOGGING SURVEY

Purpose: Provide standards and procedures for cement bond logging survey.

What: The Cement Bond Logging is supplemental to ensure compliance with the California State Division of Oil, Gas and Geothermal Resources (DOGGR) regulations (California Code of Regulations Title 14, Division 2, Chapter 4) for annual well casing integrity monitoring. “Cement bond tools measures the bond between casing and the cement placed in the annulus between the casing and the wellbore”, (Schlumberger). The measurement is made by using an acoustic sonic (Noise/temp) and ultrasonic tools.

Why: The Cement Bond Log (CBL) is to:

1. Evaluate integrity of cement sheath in the annulus between casing and formation.

2. Identify the top of cement (TOC) for potential gas migration paths, if leaks are detected. It is also for additional correlations to improve well casing integrity and safety and reduce the risk of gas leakage and unsafe operations.

When: Log is run on an as-needed basis under a standard clearance. (Note: Normally CBL is run right after the production casing is cemented in place. In some case, it is re-run to verify integrity and TOC and for correlation purposes if leaks behind casing are suspected. The only opportunity to re-run the CBL is during well rework because during rework the tubing is out of the hole and allow CBL tool to be run in the well.)

Who:

- Underground Gas Storage (UGS) Operations initiates clearances
- Contractor performs logging/testing services.
- Reservoir Engineering (RE) supervises on-site surveys
- RE reviews survey data for reasonableness and completeness.
- RE evaluates survey data and recommends course of actions, if any.

Underground Storage Risk and Integrity Management Plan

CBL Evaluation:

1. Review and evaluate the CBL survey logs to verify cement sheath bonding in the annulus between casing and formation.
2. Identify TOC and other areas that have cement bonding issues, and denote such on the well schematics for references.

CBL Technology:

- CBL utilizes the amplitude of sonic sound signal to determine bonding integrity between casing and formation.
- The tighter the bonding between the casing and formation, the less amplitude showing on the log. It is like ringing a bell and it is loud (high amplitude). The ringing bell is not as loud (low amplitude) by putting a hand on it.
- See example in Figure V-1 below for comparison between good bonding and no bonding.

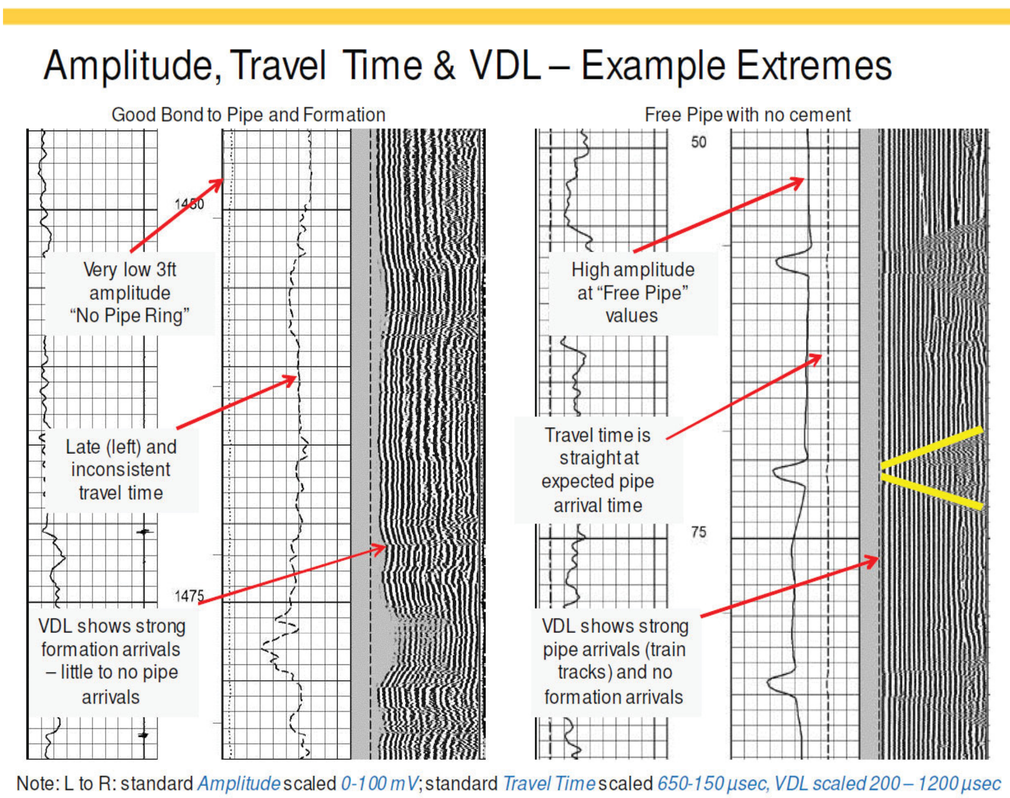


Figure V-1. Amplitude, Travel Time and VDL – Example Extremes.

Underground Storage Risk and Integrity Management Plan

Appendix V, Practice 18 - Cement Bond Logging Survey

Well Integrity Evaluation and Communication:

Note: CBL is one of the components for evaluating/monitoring gas leaks and/or gas migration. For complete evaluation/analysis, it needs to correlate with other logs (T/N, GRN, Vertilog, IE logs, etc.).

1. Evaluate and correlate apparent anomalies with the all the integrity survey (CBL, T/N, GRN, and Vertilog) results and determine how to approach the next step if there are apparent cement sheath integrity issues which contribute to gas migration.

2. Communicate results to the Reservoir Engineering department.

3. If determine to have integrity issues, elevate to higher level management for mitigation decisions.

4. Reservoir Engineering, based on the above, will prioritize remedial work, update rework prioritization spreadsheet, and input in the GSDB and S1 and S2 processes.

Figure V-2 shows a decision tree for the Cement Bond Logging.

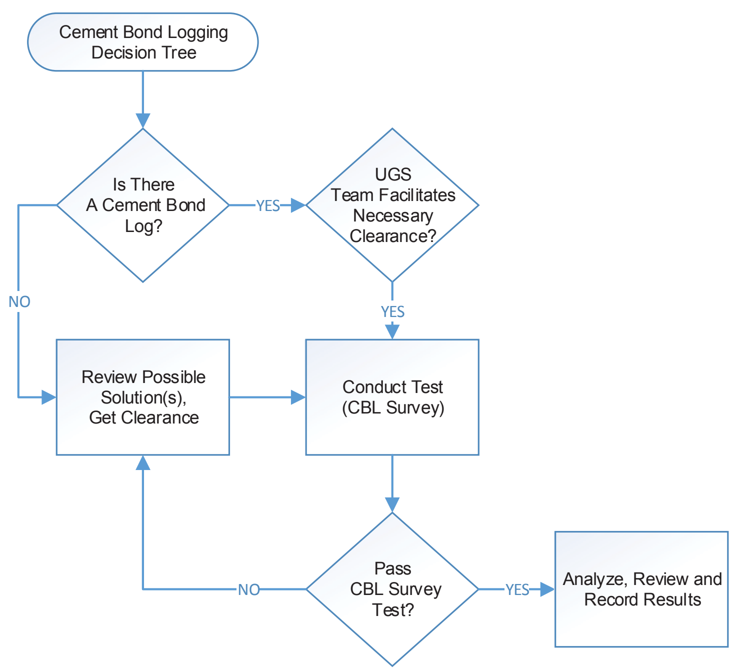


Figure V-2. Cement Bond Logging Decision Tree.

Underground Storage Risk and Integrity Management Plan

Appendix W, Glossary of Acronyms and Abbreviations

The following is a glossary of acronyms and abbreviations used in this asset management plan and related documents.

Table W-1 – Acronyms and Abbreviations

Acronym	Meaning
AFO	Asset Family Owner
AMP	Asset Management Plan
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BHP	Bottomhole Pressure
C&T	Casing & Tubing
CNL	Compensated Neutron Log
CPP	Casing Potential Profile
DOGGR	Division of Oil, Gas and Geothermal Resources
ECDA	External Corrosion Direct Assessment
EORM	Enterprise and Operational Risk Management
ESD	Emergency Shutdown
GSDB	Gas Storage Database
IC	Internal Corrosion
ICDA	Internal Corrosion Direct Assessment
IE	Induction Electrical
ILI	In-Line Inspection
I/W	Injection/Withdrawal
LOB	Line of Business
LUAF	Lost and Unaccounted for
MOP	Maximum Operating Pressure

Acronym	Meaning
MASCP	Maximum Allowable Surface Casing Pressure
MFL	Magnetic Flux Leakage
MIT	Mechanical Integrity Test
ML	Microlog
NOS	Nuclear, Operations, and Safety
OBS	Observation
PDK	Pulse and Decay
RCC	Risk and Compliance Committee
RE	Reservoir Engineering
RET	Risk Evaluation Tool
RIBA	Risk Informed Budget Allocation
RP	Recommended Practice
SCA	Surface Casing Annulus
SCCDA	Stress Corrosion Cracking Direct Assessment
SME	Subject Matter Expert
SP	Spontaneous Potential
TCA	Tubing Casing Annulus
TDT	Thermal Decay Time
TIMP	Transmission Integrity Management Program
WRO	Work Requested by Others

Underground Storage Risk and Integrity Management Plan

Appendix X, Mitigations

Page 1 of 6

The table below display threats, drivers, and prevention measures associated with the Storage asset family. In the table below are different asset types (well, reservoir, surface), potential threats or hazards, drivers, and finally mitigation measures.

The following table is lists asset type, threat(s), prevention measures, department(s), and guidance documents.

Table X-1 – Prevention Measures and Guidance Documents

Asset Type: Well			
Threat(s)	**Prevention Measure(s)**	**Department(s)**	**Reference Document(s)**
Corrosion / Erosion, Manufacturing, Equipment	Cathodic Protection	Corrosion Engineering	• TD-4181P-201: Cathodic Protection Monitoring and Restoration
	Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	Reservoir Engineering	• WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment
	Active and Plugged & Abandoned Well Evaluation (Well Schematics and Records)	Reservoir Engineering	• WELL: Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics • WELL: Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams
	Casing Inspections (CBL, GRN, N/T, Caliper, Casing Inspection Tools)	Reservoir Engineering	• TD-4550P-20: Annual Gas Well Survey Procedures • WELL: Appendix C, Casing Inspection Survey Frequency Decision Tree • WELL: Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments • WELL: Appendix T, Practice 16 - Annual Temperature / Noise logging and Data Review • WELL: Appendix U, Practice 17 - Gamma Ray Neutron Logging and Data Review • WELL: Appendix V, Practice 18 - Cement Bond Logging Survey

Table X-1 – Prevention Measures and Guidance Documents (continued)

Asset Type: Well			
Threat(s)	**Prevention Measure(s)**	**Department(s)**	**Guidance Document(s)**
Corrosion / Erosion, Manufacturing, Equipment	Monitor Well Performance Data	Reservoir Engineering	• WELL: Appendix H, Practice 4 - Sand Inspection • WELL: Appendix M, Practice 9 - Individual Well Performance Monitoring • WELL: Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring
	Monitor Casing Annular Data	Reservoir Engineering	• WELL: Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring
	Pressure Test	Reservoir Engineering	• WELL: Appendix Z, Well Integrity Testing Regime Process
	Leak Survey	Operations & Maintenance, Leak Survey	• Natural Gas Storage Facility Monitoring Plan for McDonald Island (published Oct 10, 2018) • Natural Gas Storage Facility Monitoring Plan for Los Medanos (published Oct 10, 2018) • Natural Gas Storage Facility Monitoring Plan for Pleasant Creek (published Oct 10, 2018)
Construction / Fabrication	Active and Plugged & Abandoned Well Evaluation (Well Schematics and Records)	Reservoir Engineering	• WELL: Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics • WELL: Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams
	Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	Reservoir Engineering	• WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment • API RP 1171
Incorrect Operations (Operations & Maintenance)	Guidance Documents (Operating Standards	Operations & Maintenance, Station Services	• Operating Procedures
	Operator Qualifications (OQ) Training and Development (Operations & Maintenance)	**OQ:** Gas Training & Implementation **Training and Dev:** Operations & Maintenance	• OQ: Utility Standard TD-4008S: Operator Qualification Program Requirements • Training and Dev: Apprentice Station Operator: Administrative Procedures Manual
Incorrect Operations (Well Intervention)	Active and P&A Well Evaluation (Well Schematics and records)	Reservoir Engineering	• WELL: Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics • WELL: Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams

Underground Storage Risk and Integrity Management Plan

Table X-1 – Prevention Measures and Guidance Documents (continued)

Threat(s)	Prevention Measure(s)	Department(s)	Guidance Document(s)
Asset Type: Well			
Incorrect Operations (Well Intervention)	Guidance Documents (Drilling / Completion Design Standards and Process Safety Management)	Reservoir Engineering	• WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment • API RP 1171
	OQ / Training and Development (Reservoir Engineering)	Reservoir Engineering	• Reservoir Engineer Competencies • Reservoir Specialist Competencies
	Blowout Prevention Systems	Reservoir Engineering	• API RP 1171
Asset Type: Reservoir			
Threat(s)	**Prevention Measure(s)**	**Department(s)**	**Guidance Document(s)**
Construction/ Fabrication, 1st, 2nd, 3rd Party Damage	Rules & Regulations	Reservoir Engineering	• DOGGR Regulations
	Location Design Requirements	Reservoir Engineering	• API RP 1171
	Equipment Design Requirements	Reservoir Engineering	• WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment • API RP 1171
	Land Rights	Land Rights, Reservoir Engineering	• WELL: Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
	Monitor Permit Activity	Reservoir Engineering	• WELL: Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
	Inspection During Construction	Reservoir Engineering	• API RP 1171
	Gas Sampling	Reservoir Engineering	• WELL: Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring • WELL: Appendix O, Practice 11 - Observation Well Gas Sampling
Outside Forces (Geological)	Geological and Well Evaluation of Records	Reservoir Engineering	• Geologic and Seismic Review
	Protective Boundary	Reservoir Engineering	• API RP 1171

Appendix X, Mitigations

Page 4 of 6

Table X-1 – Prevention Measures and Guidance Documents (continued)

Asset Type: Reservoir			
Threat(s)	**Prevention Measure(s)**	**Department(s)**	**Guidance Document(s)**
Outside Forces (Geological)	Land Rights	Land Rights, Reservoir Engineering	• WELL: Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
	Observation Wells	Reservoir Engineering	• WELL: Appendix L, Practice 8 - Annular Pressure and Gas Sampling Monitoring • WELL: Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring • WELL: Appendix O, Practice 11 - Observation Well Gas Sampling
	Inventory Verification	Reservoir Engineering	• WELL: Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification
Incorrect Operations	Guidance Documents (Design Standards for Fluids)	Reservoir Engineering	• API RP 1171
	Gas Quality Studies	Reservoir Engineering	• API RP 1171
	Fluid Compatibility Studies	Reservoir Engineering	• API RP 1171
	Internal Corrosion Studies	Reservoir Engineering	• API RP 1171
1st, 2nd, 3rd Party Damage (Surface Encroachments)	Land Rights	Land Rights, Reservoir Engineering	• WELL: Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties
	Public Awareness & Damage Prevention	Public Awareness	• RMP-12: Pipeline Public Awareness Program
	Patrolling / Surveillance	Operations & Maintenance, Aerial Patrol, Leak Survey	• TD-4412P-07: Patrolling Gas Pipelines • Inspection and Leak Survey Protocol for Natural Gas Storage Facilities
1st, 2nd, 3rd Party Damage (Vandalism, Terrorism, Delayed Damage)	Physical Security Systems	Operations & Maintenance	• TD-4050S: Security Standard for Gas Operations • API RP 1171

Page 5 of 6

Table X-1 – Prevention Measures and Guidance Documents (continued)

Asset Type: Surface			
Threat(s)	**Prevention Measure(s)**	**Department(s)**	**Guidance Document(s)**
1st, 2nd, 3rd Party Damage (Vandalism, Terrorism, Delayed Damage)	Public Awareness & Damage Prevention	Public Awareness	• RMP-12: Pipeline Public Awareness Program
	Patrolling / Surveillance	Operations & Maintenance, Aerial Patrol, Leak Survey	• TD-4412P-07: Patrolling Gas Pipelines • Inspection and Leak Survey Protocol for Natural Gas Storage Facilities
Weather & Outside Forces	Design Process	Station Services (Facility Design), Reservoir Engineering (Wellhead Design)	• Gas Standards & Specifications • Geologic and Seismic Review • Catastrophic Emergency Response Plan - Gas Annex: Stations and Gas Storage • WELL: Appendix E, Practice 1 - Design and Specifications for Casing, Tubing, and Wellhead Equipment
	Patrolling / Surveillance	Operations & Maintenance, Aerial Patrol, Leak Survey	• TD-4412P-07: Patrolling Gas Pipelines • Inspection and Leak Survey Protocol for Natural Gas Storage Facilities
	Remote Control Capabilities	Operations & Maintenance	• Operating Procedures
Asset Type: All Asset Types			
Threat(s)	**Prevention Measure(s)**	**Department(s)**	**Guidance Document(s)**
Major Emergency or Disaster	Emergency Shutdown Systems	Operations & Maintenance, Station Services	• Operating Procedures
	Transmission Control Center	Gas Control	• TD-4444P-02: Gas Transmission Control Center Emergency Response
	Business Continuity Plans	Gas Emergency Preparedness	• Business Continuity Plan
	Gas Emergency Response Plan (GERP)	Gas Emergency Preparedness	• EMER-3003M: Gas Emergency Response Plan
	Storage Well Crisis: Response Plan	Reservoir Engineering	• Well Control Tactical Considerations
	Storage Well Crisis: Water	Reservoir Engineering	• Well Control Tactical Considerations

Underground Storage Risk and Integrity Management Plan

Table X-1 – Prevention Measures and Guidance Documents (continued)

Asset Type: All Asset Types			
Threat(s)	**Prevention Measure(s)**	**Department(s)**	**Guidance Document(s)**
Major Emergency or Disaster	Storage Well Crisis: Equipment	Reservoir Engineering	• Well Control Tactical Considerations
	Emergency Management Advancement Program (EMAP)	Reservoir Engineering	• Catastrophic Emergency Response Plan - Gas Annex: Stations and Gas Storage
	Company Emergency Response Plan	Gas Emergency Preparedness	• EMER-3001M: Company Emergency Response Plan (CERP)
	GERP-Based Exercises	Gas Emergency Preparedness	• EMER-3003M: Gas Emergency Response Plan

Appendix Y, Production Fluid Facility Capacity Tables

Page 1 of 3

Capacities for production fluid facilities at Los Medanos, Pleasant Creek, and McDonald Island are listed in the tables below.

Table Y-1 – Production Fluid Containers – Los Medanos

Type of Container	Number of Items	Volume Per Container (Gallons)	Total Volume (Gallons)
Production Fluids Storage Tanks (C-16 & C-21)	2	8,000	16,000
Production Fluid Tanks	1	1,800	1,800
Fluid Storage Convault Tank	1	1,000	1,000
Production Fluids Tanks (in concrete Convault) at Well Sites “A”, “B”, “C” and “D”	4	500	2,000
Production Liquids Tanks (in concrete Convault) at “Pressure Limiting Station”	1	2,000	2,000
Separator (C-8) at Well Site “D”	1	210	210

Table Y-2 – Production Fluid Containers – Pleasant Creek

Type of Container	Number of Items	Volume Per Container (Gallons)	Total Volume (Gallons)
Production Fluids Storage Tank – Wellhead Yard #3-1, Wellhead Yard #4-1	2	500	1,000
Production Fluids Storage Tank – Wellhead Yard #3-2, Wellhead Yard #3-3, Wellhead Yard #3-4, Wellhead Yard #4-2	4	1,500	6,000
Production Fluids ConVault – Wellhead Yard #3-5	1	2,000	2,000

Underground Storage Risk and Integrity Management Plan

Table Y-3 – Production Fluid Containers – McDonald Island

Type of Container	Number of Items	Volume Per Container (Gallons)	Total Volume (Gallons)
Turner Cut Station			
Bulk Storage Container – Aboveground, Production Fluids Storage Tank C-30	1	27,707	27,707
Bulk Storage Container – Aboveground, Production Fluids Storage Tanks C-5 and C-6	2	12,000	24,000
Separator Units C-11, C-12, C-13, C-14	4	60	240
Contactor Towers C-1, C-2, C-3, C-4	4	400	1,600
3-Phase Separators	2	150	300
Drain Dump System C-26	1	150	150
Whisky Slough Station			
Bulk Storage Container – Aboveground, Production Fluids Storage Tank C-30	1	27,707	27,707
Bulk Storage Container – Aboveground, Production Fluids Storage Tanks C-5 and C-6	2	12,000	24,000
Separator Units C-11, C-12, C-13, C-14	4	60	240
Contactor Towers C-1, C-2, C-3, C-4	4	400	1,600
3-Phase Separators	2	150	300
Drain Dump System C-26	1	150	150
McDonald Island Compressor Station			
Bulk Storage Container – Aboveground, Pipeline Liquids Storage Tank D-1A	1	6,250	6,250
Mobile Container, Vacuum Truck	1	1,600	1,600
Separator Unites C-11, C-11A	2	75	150
Intake Scrubbers C-101, C-201	2	75	150

Table Y-3 – Production Fluid Containers – McDonald Island (continued)

Type of Container	Number of Items	Volume Per Container (Gallons)	Total Volume (Gallons)
K7 – K9 Compressor Yard			
Bulk Storage Container Aboveground, Pipeline Liquids Storage Tank D-10	1	2,000	2,000
Intake Scrubbers K7 (2), K8 (2), K9 (2)	6	55	330
Discharge Scrubbers K7, K8, K9	3	64	192
Separator Unit	1	294	294
Remote Gas Wells			
Bulk Storage Container – Aboveground, Production Fluids Storage Tanks	13	246	3,198

Appendix Z, Well Integrity Testing Regime Process – Production Casing

Page 1 of 1

The following flow chart illustrates the testing regime process that PG&E utilizes for performing and assessing well integrity during rework operations where a full assessment is performed. Reassessment frequency is guided by Appendix S, Appendix K, and Section 10.1.

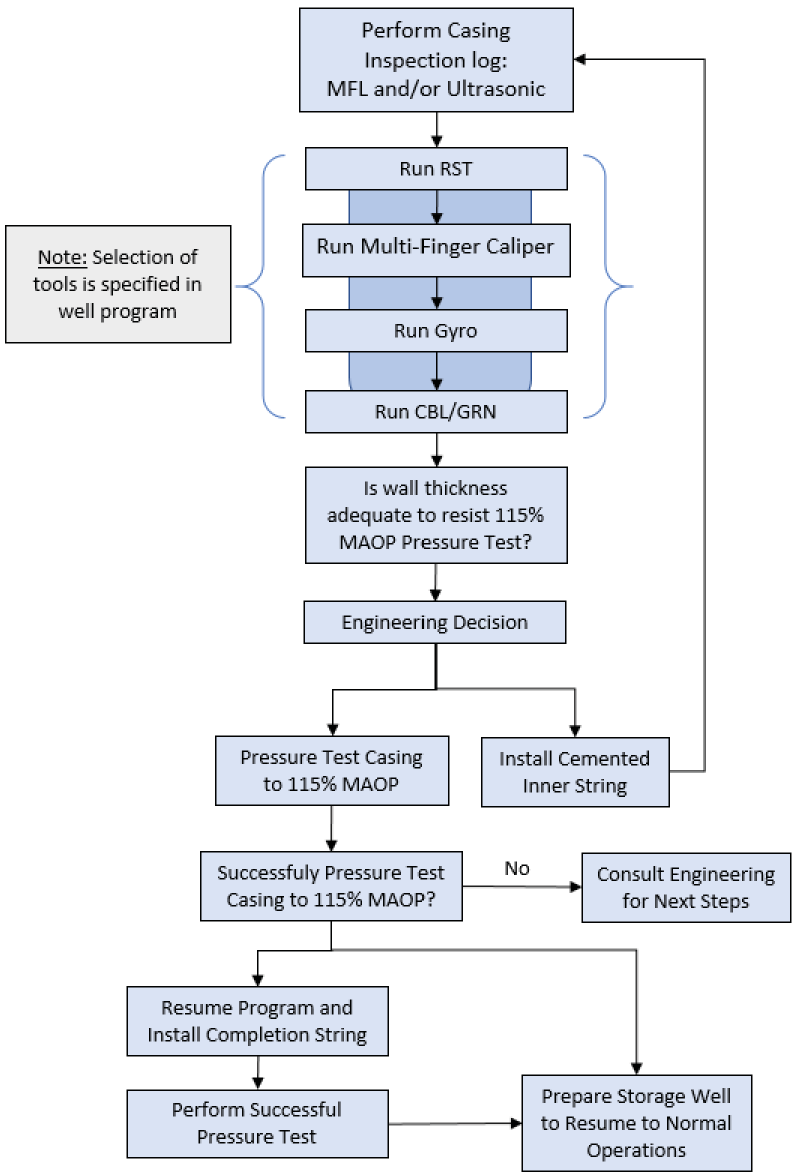


Figure Z-1 – Well Integrity Testing Regime Process

Underground Storage Risk and Integrity Management Plan

Appendix AA, Records Inventory

This table lists the set of data and records associated with PG&E's underground storage engineering, operations and maintenance, provided as a reference for PG&E personnel. This is a living document and as of 03/29/2019 should be considered comprehensive, but not 100% complete.

NOTE: The source file for this is found in the compliance masterfile Excel workbook.

Table AA – Records Inventory

Section	Data/ Records/ Test/ Survey/ Monitoring/ Analysis	Summary Description	Gas Sto Asset Mgmt Database	GPOM	Gas Ops Safety Dept	Environmental	Gas Ops Corrosion Dept	Gas Ops Records	Gas Emer Prep Team	Sourcing	Process Safety	Land Rights	Corporate Training
7	D	simple high-level rqmts											
8	S M	mentions some surveys											
8.1	D	apparently extensive list of reservoir characterization data types	x										
8.4	D	lists observation well data, Gas Storage Database (GSDB). Pressure, gas samples, storage zone											
8.4	D	pressure data	x	x									
8.4	D	gas composition samples	x										
8.4	D	fluid type/composition	x	x									
8.4	A	comparison of data from different wells	x										
8.4	D	well mechanical integrity history	x										
8.4	D	annual pressure data	x		x								
8.4	D A	defects and defect rate of change in casing inspection log	x										
8.4	D	well location	x										
8.4	D	well use (Inj/wdwl)	x										
8.5	D	frequence of risk monitoring of third party wells	x										
8.5.1	D	3rd PARTY WELLS - list of existing 3rd party well data types	x										
8.5.1	D	well location, serial, and state permit or API number, production interval, total depth, and operator	x										
8.5.1	D	well data, schematics, and logs, and results from a thorough review of state files	x										
8.5.1	D	gas, oil, and water production data from the state and/or well data from service companies	x										
8.5.1	D	annual production data	x										
8.5.1	A	anomolies in annual prodution data	x										
8.5.1	D	third party well gas constituents	x										

Underground Storage Risk and Integrity Management Plan

Section	Data/ Records/ Test/ Survey/ Monitoring/ Analysis	Summary Description	Gas Sto Asset Mgmt Database	GPOM	Gas Ops Safety Dept	Environmental	Gas Ops Corrosion Dept	Gas Ops Records	Gas Emer Prep Team	Sourcing	Process Safety	Land Rights	Corporate Training
8.5.1	A	3rd party vs storage gas constituents	x										
8.5.1	D	annular and tubing pressure	x										
8.5.1	D	constituents of gas streams including the tubing and the tubing-casing annuli (TCA),	x										
8.5.1	D	well design and completion	x										
8.5.1	A	Verify that the storage zone will be properly isolated by cement and that the casing design is adequate for storage field pressures	x										
8.5.2	D	list of new 3rd party well data types	x										
8.5.2	D A	monitor the drilling, cementing, logging, and perforating operations of third-party wells	x										
8.5.2	D	available logs	x										
8.5.2	A	identify anomolies in available logs	x										
8.6	D	list of lost and unaccounted for gas data types											
8.6	D	engine start gas / start count		x									
8.6	D	Venting volume of compressor and piping each time a unit is shut down and the number of times it is shut down each month		x									
8.6	D	ESD blowdown volumes		x									
8.6	D	equipment depressurizing event volumes		x									
8.6	D	station fuel		x									
8.6	D	well blowdown volumes	x										
8.6	D	transmission pipe blowdown volumes		x									
8.6	D	relief valve event volumes		x									
8.6	D	atmospheric tank flash gas		x									
8.6	D	flare gas		x									
8.6	D	diffuse gas losses (leaks)		x									
11	D R	safety valve maint and repair records	x	x									
13	D	corrosion monitoring data mentioned but not detailed. Surface equipment		x			x						
13	D	corrosion control / monitoring plan for each field					x						
13	D	corrosion monitoring data mentioned but not detailed. Well sub-surface equipment	x										
15	D	mention of data to support threat and risk mgmt	x										

Underground Storage Risk and Integrity Management Plan

Section	Data/ Records/ Test/ Survey/ Monitoring/ Analysis	Summary Description	Gas Sto Asset Mgmt Database	GPOM	Gas Ops Safety Dept	Environmental	Gas Ops Corrosion Dept	Gas Ops Records	Gas Emer Prep Team	Sourcing	Process Safety	Land Rights	Corporate Training
15.1.4	D	mentions data quality for risk mgmt	x										
15.2.1	D	characterizes threat matrix and documenting data quality status	x										
15.2.2	D	mentions use of data in risk identification and evaluation	x										
15.2.2.e	D	mention of data to support threat and risk mgmt	x										
15.4.1	D	characterizes threat matrix and documenting data quality status	x										
15.4.4	D	mentions new data is use to support AMP evolution	x										
15	D	IFR rqmt for use of data in risk mgmt	x	x	x	x	x			x	x	x	
18		Abnormal Operating Conditions	x	x									
18		Abnormal Operating Condition training for well work contractors	x										
19	R	Emergency Response Exercise Plan Report	x										
Emer	R	GERP training records							x				
Emer	R	Training records	x										x
20		Change Control											
MoC		MoC well work related	x										
MoC		Log for MoCs in Process Safety Dept									x		
MoC		MoC for processes									x		
MoC		Log for MoCs in GSAM	x										
21	D	water production report	x	x		x							
21	D	inventory verification report	x										
21	D	Yearly Storage Well Evaluation Report	x										
21	D	Gas Injection and Production Reports	x	x									
21	D	Gas Injection and Production Report source data		x									
21	D	Asset Management Plan	x										
23	R	Internal and external auditing reports/findings	x										
Apdx B.E	D	requires offset data be obtained to supplement well inspection survey											
Apdx D.A.2	D	mentions well construction data	x										
Apdx E P1 E.6	D	lists well records, casing inspection logs, and mentions "mechanical integrity test data" for review when planning reworks	x										
Apdx E P1 8	R	emergency response plan	x										

Underground Storage Risk and Integrity Management Plan

Section	Data/ Records/ Test/ Survey/ Monitoring/ Analysis	Summary Description	Gas Sto Asset Mgmt Database	GPOM	Gas Ops Safety Dept	Environmental	Gas Ops Corrosion Dept	Gas Ops Records	Gas Emer Prep Team	Sourcing	Process Safety	Land Rights	Corporate Training
Apdx E P1 8	R	emergency response drill plans and reports	x										
Apdx E P1 8	R	emergency response personnel responsibilities and familiarity documentation											
Apdx E P1 E.11 6.5	D	mentions post treatment monitoring data and analysis	x										
Apdx E P1 E.11 6.9	D	mentions mechanical integrity test data and pressure test data	x										
Apdx E P1B 2.5	D	mentions historical field data in the context of Production Liner & Gravel Pack Design	x										
Apdx E P1B 6.1	D	mentions post-treatment monitoring data	x										
Apdx E P1B 6.1	D	mentions mechanical integrity test data and pressure test data	x										
Apdx H P4 1	D	sand residue inspection data ratings detail / gas storage database	x	x									
Apdx H P4 4	D	rqmt to update database and safe flow rates table	x										
Apdx J P6	D	high level description of Christmas tree pressure data. Mentions well pressure data form	x										
Apdx L P8	D	Surface Casing Annular (SCA) Pressure and Gas Sampling Monitoring & assessment	x										
Apdx L P8	D	annular / SCA pressure data	x										
Apdx L P8	D	log investigations – cement bond, noise, temperature, neutron, etc.	x										
Apdx L P8	D	corrosion hole, pit or pre-existing condition. Pit geometry and depth.	x										
Apdx L P8	D	High Resolution vertilog	x										
Apdx L P8	D A	gas sampling and assessment of storage v native gas	x										
Apdx L P8	D	venting rate	x										
Apdx L P8	D A	well history and local information	x										
Apdx L P8	A	trend SCA pressure, venting rate, and gas sampling data and performs field and well integrity evaluation. includes pressure versus time and historical sampling comparisons	x										

Underground Storage Risk and Integrity Management Plan

Section	Data/ Records/ Test/ Survey/ Monitoring/ Analysis	Summary Description	Gas Sto Asset Mgmt Database	GPOM	Gas Ops Safety Dept	Environmental	Gas Ops Corrosion Dept	Gas Ops Records	Gas Emer Prep Team	Sourcing	Process Safety	Land Rights	Corporate Training
Adx M P9	D	mentions data collected, presumably well injection and withdrawal performance	x										
Apdx N P10	D	casing and tubing pressure data, assessment and entry to GSDB	x										
Apdx N P10	D	casing pressure data	x										
Apdx N P10	D	tubing pressure data	x										
Apdx N P10	D	annular pressure data	x										
Apdx O P11	D	fluid, pressure, annual pressure data, inspection logs, location, reservoir pressure, gas analysis	x										
Apdx O P11	D	observation, inj and wdwl gas & fluid samples and corresponding zones	x	x									
Apdx O P11	A	review and assessment of monthly observation and selected I/W well gas sample results	x										
Apdx O P11	D	well integrity history	x										
Apdx P P12	D	Field Shut In Testing for Storage Gas Inventory Verification - pressure and inventory data, high-level description of assessment, mentions "operating data", presumably injection and withdrawal volumes and field pressure, and assessment of data	x										
Apdx P P12	D	weekly shutin pressure	x										
Apdx P P12	A	storage gas inventory and pressure relationship	x										
Apdx P P12	A	annual inventory report / reasonable engineering uncertainty	x										
Apdx P P12	A	non-effective gas volume	x										
Apdx P P12	A	impounded gas volume	x										
Apdx R P14	D	"test data" for DHSV but doesn't describe the data provided on GPOM test log documents	x	x									
Apdx R P14	D	DHSV CPUC rqmt test results (exercising only)		x									
Apdx R P14	D	DHSV DOGGR and CPUC test procecedure		x									
Apdx R P14	D	DHSV DOGGR test final review	x										

Underground Storage Risk and Integrity Management Plan

Section	Data/ Records/ Test/ Survey/ Monitoring/ Analysis	Summary Description	Gas Sto Asset Mgmt Database	GPOM	Gas Ops Safety Dept	Environmental	Gas Ops Corrosion Dept	Gas Ops Records	Gas Emer Prep Team	Sourcing	Process Safety	Land Rights	Corporate Training
Apdx R P14	D	leakage rates	x	x									
Apdx S P15	D	casing inspection logging data, lists a variety of data collection types, summarizes evaluation,	x										
Apdx S P15	D	Reductions to casing wall thickness (Casing Inspection Tools)	x										
Apdx S P15	D	Caliper	x										
Apdx S P15	D	Identification of gas presence behind the casing (Gamma Ray Neutron – GRN)	x										
Apdx S P15	D	Presence of a corrosion cell (Casing Protection Profile – CPP)	x										
Apdx S P15	D	Temperature Logs	x										
Apdx S P15	D	Noise Logs	x										
Apdx S P15	D	Downhole video cameras and/or downhole video side view cameras	x										
Apdx S P15	D	E-Log-I Surveys	x										
Apdx S P15		OPEN HOLE LOGS	x										
Apdx S P15	D	Caliper	x										
Apdx S P15	D	Density w/Pe (Litho-Density)	x										
Apdx S P15	D	Compensated Neutron Log (CNL)	x										
Apdx S P15	D	Spontaneous Potential (SP)	x										
Apdx S P15	D	Gamma Ray (GR)	x										
Apdx S P15	D	Resistivity Logs (Dual-Induction or Array Induction)	x										
Apdx S P15	D	Microlog (ML)	x										
Apdx S P15		CASED HOLE LOGS	x										
Apdx S P15	D	Casing Inspection Tools (i.e., Vertilog, MicroVertilog, High-Resolution Vertilog, Caliper, and Ultrasonic inspections)	x										
Apdx S P15	D	Cement Bond Log/Cement Mapping Tool with Gamma Ray and Casing Collar Locator or Segmented Bond Tool with	x										

Underground Storage Risk and Integrity Management Plan

Section	Data/ Records/ Test/ Survey/ Monitoring/ Analysis	Summary Description	Gas Sto Asset Mgmt Database	GPOM	Gas Ops Safety Dept	Environmental	Gas Ops Corrosion Dept	Gas Ops Records	Gas Emer Prep Team	Sourcing	Process Safety	Land Rights	Corporate Training
		Gamma Ray and Casing Collar Locator											
Apdx S P15	D	Base line TDT/PDK with Gamma Ray and Casing Collar Locator or Gamma Ray Neutron with Casing Collar Locator	x										
Apdx S P15	D	Annual Noise, Temperature, and GRN logs	x										
Apdx S P15	D	Cathodic protection system verification data	x				x						
Apdx T P16	A	analysis of data, comparison of anomalies over time, etc.	x										
Apdx T P16	D	temperature survey data	x										
Apdx T P16	D	noise logging data	x										
Apdx U P17	D	Gamma Ray Neutron Logging and Data - describes data types	x										
Apdx U P17	A	analysis of GRN data	x										
Apdx V P18	D	Cement Bond Logging Survey- describes data types	x										
Apdx V P18	A	analysis of CBL data	x										
Category													
Design	R	Third party equipment records (foreign prints) / GSAM shared drive	x					x					
M&O	R	surface equipment leak surveys		x									
M&O	R	well work contractor safety	partial		x					x			
M&O	R	GSAM well work programs	x										
M&O	R	weekly rig operations drill record	x										
M&O	R	daily well work reportx	x										
M&O	R	Training records	x										x
Process Safety	R	process safety reporting (PSSRs, HAZOP, PHAsetc) specifc to assets (well work)	x										
Process Safety	R	process safety reporting (PSSRs, HAZOP, PHAs, etc) for broader processes									x		
Process Safety	R	process safety reporting (PSSRs, HAZOP, PHAs etc) for rig operations	x		x								
Safety	R	site safety plan created by contractor	x		x								
	R	land rights documentation	x									x	

Underground Storage Risk and Integrity Management Plan

Appendix AB, Guidance Document Reference

This table lists the set of guidance documents associated with PG&E's underground storage engineering, operations and maintenance, provided as a reference for PG&E personnel. This is a living document and as of 1/15/18 should be considered comprehensive, but not 100% complete.

Guidance documents fit within two general business categories: the storage-specific business, and the broader Gas Operations business. For circumstances in which storage asset management involves technology, equipment and/or processes that are specific storage assets, specific guidance documents have been developed and included in this IMP. These are listed in the first portion of the following table. The guidance documents broadly applicable across Gas Operations (including those applicable across all of PG&E) appear in the lower portion of the table. These all form an integrated set of guidance for storage asset management. Duplication of content between storage and Gas Operations/PG&E guidance is avoided to prevent the potential for conflicting guidance.

Storage-specific guidance documents including this plan are maintained on the GSAM share point, GSAM shared drive, GPOM share point, and are made available electronically upon request.

Gas Operations and applicable PG&E guidance documents are maintained on the Gas Operations technical information library (TIL) by the Gas Operations Standards Engineering Department. Applicable PG&E guidance documents are maintained by the document owners specified in the table below.

NOTE: The source file for this is found in the compliance masterfile Excel workbook.

Table AB – Guidance Document Inventory

IMP Section	IMP Table of Contents and Independent Document	Document Owner
1	Summary	GSAM
2	Target Audience	GSAM
3	Regulatory Jurisdiction for Company Gas Storage Fields	GSAM
4	Roles and Responsibilities	GSAM
5	Flow of Plan Activities and Frequency of Plan Updates	GSAM
6	UGS Integrity Management Process	GSAM
7	Data Management	GSAM
8	Reservoir Integrity	GSAM
9	Mechanical Integrity of Wells	GSAM
10	Casing Pressure Tests and Annulus Monitoring	GSAM
11	Safety Valve Maintenance	GSAM
11	Draft functional Platform Safety Valve Test Procedure.docx	GSAM
11	McDonald Island Downhole Safety Valve (DHSV) Test 4-12-2016.doc	GSAM
11	McDonald Island Non-Platform Uphole Safety Valve (UHSV) Test 4-14-2016.doc	GSAM
11	McDonald Island Uphole Safety Valve (UHSV) Test 4-14-2016.doc	GSAM
11	MI DHSV TEST FORM.xlsx	GSAM
11	MI LM PC UHSV TEST FORM.xlsx	GSAM

Underground Storage Risk and Integrity Management Plan

IMP Section	IMP Table of Contents and Independent Document	Document Owner
11	LM DHSV TEST FORM.xlsx	GSAM
11	Los Medanos Downhole Safety Valve (DHSV) Test 4-11-2016.doc	GSAM
11	Los Medanos Uphole Safety Valve (UHSV) Test 4-11-2016.doc	GSAM
11	Pleasant Creek Uphole Safety Valve (UHSV) Test 4-12-2016.doc	GSAM
12	Wellhead Valve Maintenance	GSAM
12	Utility Procedure: TD-4430P-04, Gas Valve Maintenance including major station maintenance, flammable mtls., etc.	GSAM
12	Detailed wellhead valve testing and maintenance procedures and data collection forms issued by GPOM	GSAM
12	McDonald Island Christmas Tree Valve Testing Non-Platform 4-13-2016.doc	GSAM
12	MI LM PC CHRISTMAS TREE VALVE TEST FORM.xlsx	GSAM
12	Los Medanos CHRISTMAS TREE TEST FORM_03232016.xlsx	GSAM
12	Los Medanos Christmas Tree Valve Testing Program 4-11-2016.doc	GSAM
12	Pleasant Creek Christmas Tree Valve Testing Program 4-11-2016.doc	GSAM
13	Corrosion Monitoring and Evaluation	GSAM
14	Evaluation of Wells and Attendant Production Facilities	GSAM
15	Threat and Risk Management	GSAM
16	Asset Management Plans	GSAM
17	Prioritization of Risk Mitigation Efforts	GSAM
18	TD-4800S, Continuing Surveillance	Codes & Standards
19	Emergency Response / Emergency Preparedness	GSAM
19	Gas Emergency Response Plan	GSAM
19	Well Control Tactical Considerations Plan (WCTCP), including Site-Specific Surface Intervention and Relief well plans	GEP/GSAM
19	Catastrophic Emergency Response Plan - Annex: Stations and Gas Storage - Gas Annex - Gas Storage.docx	GEP
19	EMER-1010S_EMER-1010S+Maintaing+and+Updating+Emergency+Response+Plans.pdf	GEP
19	EMER-6010S_Gas+Emergency+Response+Plan+Training,+Exercise,+and+Evaluation.pdf	GEP
19	TD-4444P-02: Gas Transmission Control Center Emergency Response	Codes & Standards
19	Business Continuity Plan	GEP
19	EMER-3001M: Company Emergency Response Plan (CERP)	EP
19	EMER-3003M: Company Emergency Response Plan (GERP)	GEP
19	Emergency Response Exercise Plan (created for each exercise)	GEP
19	Blowout Prevention in California - Equipment Selection and Testing (DOGGR blowout prevention practice)	External Reference
20	Security	Corp Security

Underground Storage Risk and Integrity Management Plan

IMP Section	IMP Table of Contents and Independent Document	Document Owner
20	TD-4050S: Security Standard for Gas Operations	Codes & Standards
20	SCC2001S – Corporate Security	Corp Security
20	McDonald Island Security Plan 9/9/2010	FIMP
20	McDonald Island Security Vulnerability Assessment	FIMP
20	Los Medanos Security Plan 3/1/2010 updated 4/18/13	GSAM
20	Pleasant Creek Security Plan not yet developed - relies on TD-4050S	GSAM
20	TD-4640P-01 that addresses hot work	Codes & Standards
20	TD-4551P-07 that addresses hazardous area classification	Codes & Standards
20	TD-4430P-02 that covers general major gas transmission station maintenance, and includes general requirements for locating flammable material at compressor stations.	Codes & Standards
21	Change Control	Codes & Standards
21	MoC - Reservoir Engineering MoC Process Revision 2015-03-17.pdf	GSAM
21	MoC - Utility Standard: TD-4014S - Change Control (Management of Change) (TD-4014S.pdf or some version of this)	GSAM
21	MoC - Utility Procedure TD-4014P-01 - Field Change Control Process (TD-4014P-01.pdf or some version of this)	GSAM
21	MoC form associated with TD-4014S - Change Control . Field Change Control Form from Gas Operations Procedure TD-4014P. (MoC Form D-4014P-01-FO1, Rev. 1.docx or some version of this)	GSAM
21	MoC for Manned Stations - Station Operations Control Room Management of Change.docx - this MOC practice as a reference from the Gas Control Strategy & Support Team. This is the MOC procedure for manned stations, including storage facilities.	GSO
22	Communication Plan	GSAM
23	Records	GSAM
23	GOV-7101S_GOV-7101S+Records+Management+Standard.pdf	ERIM
24	Internal Auditing	GSAM
25	Compliance Requirements / Regulatory Commitment	GSAM
26	Document Contacts	GSAM
27	Revision Notes / Change Log	GSAM
A	Appendix A, Well Logging Criteria for New Wells	GSAM
B	Appendix B, Additional Investigations	GSAM
C	Appendix C, Casing Inspection Survey Frequency Decision Tree	GSAM
D	Appendix D, Remedial Options and Decision Tree	GSAM
E	Appendix E, Practice 1 - Design and Specifications for Construction of Natural Gas Storage Wells	GSAM
F	Appendix F, Practice 2 - Creating and Updating Storage Wellbore Schematics	GSAM
G	Appendix G, Practice 3 - Creating and Updating Storage Wellhead Diagrams	GSAM

Underground Storage Risk and Integrity Management Plan

IMP Section	IMP Table of Contents and Independent Document	Document Owner
H	Appendix H, Practice 4 - Sand Inspection	GSAM
I	Appendix I, Practice 5 - Uphole Safety Valve (UHSV) Test Procedures	GSAM
I	Appendix I. Detailed UHSV testing procedures and data collection forms issued by Reservoir Engineering,	GSAM
J	Appendix J, Practice 6 - Christmas Tree Pressure Monitoring	GSAM
K	Appendix K, Practice 7 – Mechanical Integrity Test Acceptance Frequency	GSAM
L	Appendix L, Practice 8 – Annular Pressure and Gas Sampling Monitoring	GSAM
M	Appendix M, Practice 9 - Individual Well Performance Monitoring	GSAM
N	Appendix N, Practice 10 - Wellhead Annuli Pressure Monitoring	GSAM
O	Appendix O, Practice 11 - Observation and Selected I/W Well Gas Sampling	GSAM
P	Appendix P, Practice 12 - Field Shut In Testing for Storage Gas Inventory Verification	GSAM
Q	Appendix Q, Practice 13 - Monitoring Third Party Activities Inside and Outside of Gas Storage Properties	GSAM
R	Appendix R, Practice 14 - Downhole Safety Valve (DHSV) Testing	GSAM
R	DHSV Manufacturer Instructions	GSAM
R	DHSV Testing Procedure and documentation used by GPOM - McDonald Island	GSAM
R	DHSV Testing Procedure and documentation used by GPOM - Los Medanos	GSAM
R	DHSV Testing Procedure and documentation used by GPOM - Pleasant Creek	GSAM
S	Appendix S, Practice 15 - Casing Inspection Logging and Data Assessments	GSAM
T	Appendix T, Practice 16 - Annual Temperature / Noise Logging and Data Review	GSAM
T	TD-4550P-20: Annual Gas Well Survey Procedures - wireline procedure PPSOT-GUID-000005967.pdf	GSAM
U	Appendix U, Practice 17 - Gamma Ray Neutron Logging and Data Review	GSAM
V	Appendix V, Practice 18 - Cement Bond Logging Survey	GSAM
W	Appendix W, Glossary of Acronyms and Abbreviations	GSAM
X	Appendix X, Mitigations	GSAM
Y	Appendix Y, Production Fluid Facility Capacity Tables	GSAM
Z	Appendix Z, Well Integrity Testing Regime Process	GSAM
AC	Appendix AC, Gas Storage Asset Management - Change Control for Well Rework Process	GSAM
AD	Appendix AD, Rig Evacuation Procedure	GSAM
AE	Appendix AE, PG&E Underground Storage Facility Drilling/Rework Safety and Environmental Plan	GSAM

Underground Storage Risk and Integrity Management Plan

IMP Section	IMP Table of Contents and Independent Document	Document Owner
AF	Appendix AF, PG&E Underground Storage Facility Signage	GSAM
AG	Appendix AG, Well Work	GSAM
AH	Appendix AH, Well Work Contractor Competency	GSAM
AI	Appendix AI, Rathole Drilling Program	GSAM
AJ	Appendix AJ, Well Kill Program	GSAM
AK	Appendix AK, Well Bring-in Procedure	GSAM
AL	Appendix AL, BOP Inspection Process	GSAM
Category	**Non-IMP Document**	**Document Owner**
Code	API 14C	NA
Code	API 6A - ref IPM Apdx E - design	NA
Code	API RP 1171	NA
TIL Doc	TD-4870P-01 Gas Well Wireline Procedure	GSAM/Design Stds Dept
Environ	Minor Source Compliance Assurance Manual, Natural Gas Transmission Air Quality Management Plan - Facility: Pleasant Creek Underground Gas Storage Facility	Environmental Services
Environ	Natural Gas Underground Storage Facility Monitoring Plan, Facility: Los Medanos, Revised: October 10, 2018	Environmental Services
Environ	Natural Gas Underground Storage Facility Monitoring Plan, Facility: McDonald Island, Revised: October 10, 2018	Environmental Services
Environ	Natural Gas Underground Storage Facility Monitoring Plan, Facility: Pleasant Creek, Revised: October 10, 2018	Environmental Services
Environ	Spill Prevention Control and Countermeasure (SPCC) Plan - Los Medanos Underground Natural Gas Storage Facility	Environmental Services
Environ	Spill Prevention Control and Countermeasure (SPCC) Plan - McDonald Island Underground Natural Gas Storage Facility	Environmental Services
Environ	Spill Prevention Control and Countermeasure (SPCC) Plan - Pleasant Creek Underground Natural Gas Storage Facility	Environmental Services
Environ	Synthetic Minor Program Compliance Assurance Manual, Natural Gas Transmission Air Quality Management Plan - Facility: Los Medanos Underground Gas Storage Facility	GPOM / Environmental Services
Environ	Title V Compliance Assurance Manual, Natural Gas Transmission Air Quality Management Plan - Facility: McDonald Island Underground Gas Storage Facility	GPOM / Environmental Services
M&O	Hazardous Energy Control (Lockout/Tagout) for Gas Clearances TD-4441P-20, Rev. 0a GasOpsLOTO.pdf	Gas Operations / Engr/Design Stds Dept
M&O	Facility Security Checklist	Corporate Security
M&O	LM_03_01_16(Date)_Annular Monitoring_FORM.xlsx	GSAM
M&O	Los Medanos Annular 4-11-2016.doc	GSAM

Underground Storage Risk and Integrity Management Plan

Category	Non-IMP Document	Document Owner
M&O	Los Medanos Wells Pressure Data Form.pdf	GSAM
M&O	Los Medanos Wells Pressure Data FORM_03182016.xlsx	GSAM
M&O	McDonald Island Non-Platform Annular 4-13-2016.doc	GSAM
M&O	McDonald Island Platform Annular 4-13-2016.doc	GSAM
M&O	McDonald Island Wells Pressure Data Form.xlsx	GSAM
M&O	McDonald Island Wells Pressure Data FORM_03192016.xlsx	GSAM
M&O	McDonald Island_Los Medanos_Pleasant Creek Wells Pressure Data FORMS.xlsx	GSAM
M&O	MI_3_2_16(Date)_Annular Monitoring_FORM.xlsx	GSAM
M&O	MI_LM_PC (DATE)_ANNULAR MONITORING_FORM.xlsx	GSAM
M&O	Operating Procedures - Los Medanos	GPOM
M&O	Operating Procedures - McDonald Island	GPOM
M&O	Operating Procedures - Pleasant Creek	GPOM
M&O	OQ:Utility Standard TD-4008S: Operator Qualification Program Requirements	Codes & Standards
M&O	PC_03_01_16 (Date)_Annular Monitoring_FORM.xlsx	GSAM
M&O	Pleasant Creek Annular Monitoring.doc	GSAM
M&O	Pleasant Creek Wells Pressure Data Form.pdf	GSAM
M&O	Pleasant Creek Wells Pressure Data Form.xlsx	GSAM
M&O	Pleasant Creek Wells Pressure Data FORM_03192016.xlsx	GSAM
M&O	Pressure reading procedures and data logging forms used by GPOM	GSAM
GSAM Engineering	Geologic and Seismic Review	GSAM
GSAM Engineering	Reservoir Engineer Competencies	GSAM
GSAM Engineering	Reservoir Specialist Competencies	GSAM
GSAM	Rework Gas Monitoring Program 07102015 Version 1 FINAL.docx	GSAM
TIL Doc	RMP-12: Pipeline Public Awareness Program	TIMP

Appendix AC, Gas Storage Asset Management - Change Control for Well Rework Process

Well engineering, design and rework shall include and follow the MOC process as described below in one of the following categories. Examples of the qualifying events are listed below each category for ease of reference. The following pages include the specific instruction for each category.

- **Category 1 MOC** – Approval Requirement: Inform and Communicate

Category 1 MOC Example Activities	1) Increase or decrease mud weight 2) Increase or decrease mud viscosity 3) Change of logging sequencing for efficiency 4) Change of retrievable BP setting depths 5) Change of chemical or mechanical cut depths

- **Category 2 MOC** – Approval Requirements: Communication and On-Call Engineer or Manager Approval

Category 2 MOC Example Activities	1) Change of logging depths 2) Change of under-reaming depths 3) Change of open hole sizes 4) Change of pipe recovery operation

- **Category 3 MOC** – Approval Requirements: Principal Engineer or Manager and Director of Reservoir Engineering

Category 3 MOC Example Activities	1) Changes that impact permits 2) Change of production casing setting depths during cementing 3) Change of production liner packer setting depths 4) Sidetrack 5) Abandon 6) Unplanned plug-back 7) Pipe or wireline stuck in the hole that requires backing or shooting off tools

Category 1 MOC – Approval Requirement: Inform and Communicate

Certain event and/or step changes are for information and communication only during well rework operation, such as:

1) Increase or decrease mud weight
2) Increase or decrease mud viscosity
3) Change of logging sequencing for efficiency
4) Change of retrievable BP setting depths
5) Change of chemical or mechanical cut depths

Note: Category 1 MOC changes must be within permit requirements (Category 3)

These type event changes will follow a Category 1 MoC process structure with the following steps:

A. Initiation by the Well Site Manager (WSM) on duty.

- Gather and document information about event that triggered the change.
- Determines if additional support is necessary for risk assessment.
- Communicate the change and what triggered the change by send an email to all stakeholders and contractors.
- Record the change in the daily report.
- Make change in the well rework program and highlight the change.
- Send revised well rework program to all stakeholders including contractors denoting revision number of the revised program.
- On-call Engineer reviews the revised program
- Project Manager (PM) uploads the revision to Unifier and inform all stakeholders.
- Documentation: Category 1 MOC documentation will be saved in the applicable daily field report by Reservoir Engineering and not tracked in a central repository.
- Format: A MOC log will be created to track all MOC's. The following title format should be used in emails and change control form: STO-MOC_MI_Well_XXXX_20XX.

Underground Storage Risk and Integrity Management Plan

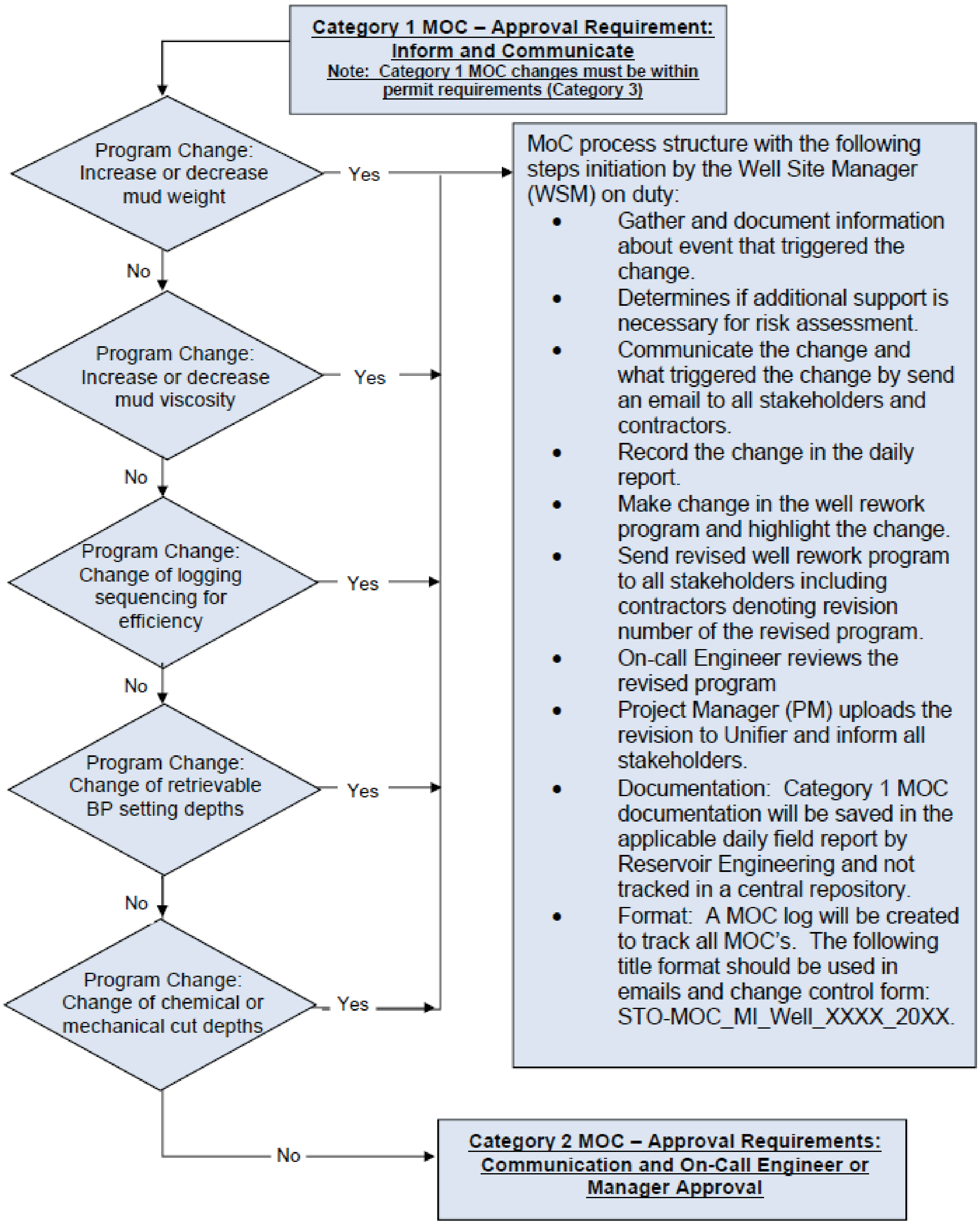


Figure AC-1: Category 1 MOC Decision Flow Chart

<u>Category 2 MOC – Approval Requirements: Communication and On-Call Engineer or Manager Approval</u>

Director of Reservoir Engineering may designate authority to other individuals for Category 2 MOC Manager Approval

Certain event and/or step changes require communication and MOC approval during well rework operation, such as:

1) Change of logging depths
2) Change of under-reaming depths
3) Change of open hole sizes
4) Change of pipe recovery operation

Note: Category 2 MOC changes must be within permit requirements (Category 3)

These type event changes will follow a Category 2 MoC process structure with the following steps:

A. Initiation by the Well Site Manager (WSM) on duty.

- Gather and document information about event that triggered the change.
- Determines if additional support is necessary for risk assessment.
- Communicate the change and what triggered the change by send an email to all stakeholders and contractors.
- Obtain verbal approval from On-Call Engineer or PM&O Manager.
- Record the change in the daily report.
- Make change in the well rework program and highlight the change.
- Send revised well rework program to all stakeholders including contractors denoting revision number of the revised program.
- On-call Engineer reviews the revised program

B. Change initial endorsement by Reservoir Engineering department following the activities:

- Follow the Field Change Control Process for each documented change through MoC Process.to complete the Field Change Control Form
- Support with additional risk assessment activities if necessary
- Obtain approval signatures from On-Call Engineer or PM&O Manager
- Project Manager (PM) uploads the revision to Unifier and inform all stakeholders.
- Documentation: Category 2 MOC documentation will use the change control sharepoint as the central repository of the documentation. Send all communication to Change Control email: ChangeControl@pge.com
- Format: A MOC log will be created to track all MOC's. The following title format should be used in emails and change control form: STO-MOC_MI_Well_XXXX_20XX.

Underground Storage Risk and Integrity Management Plan

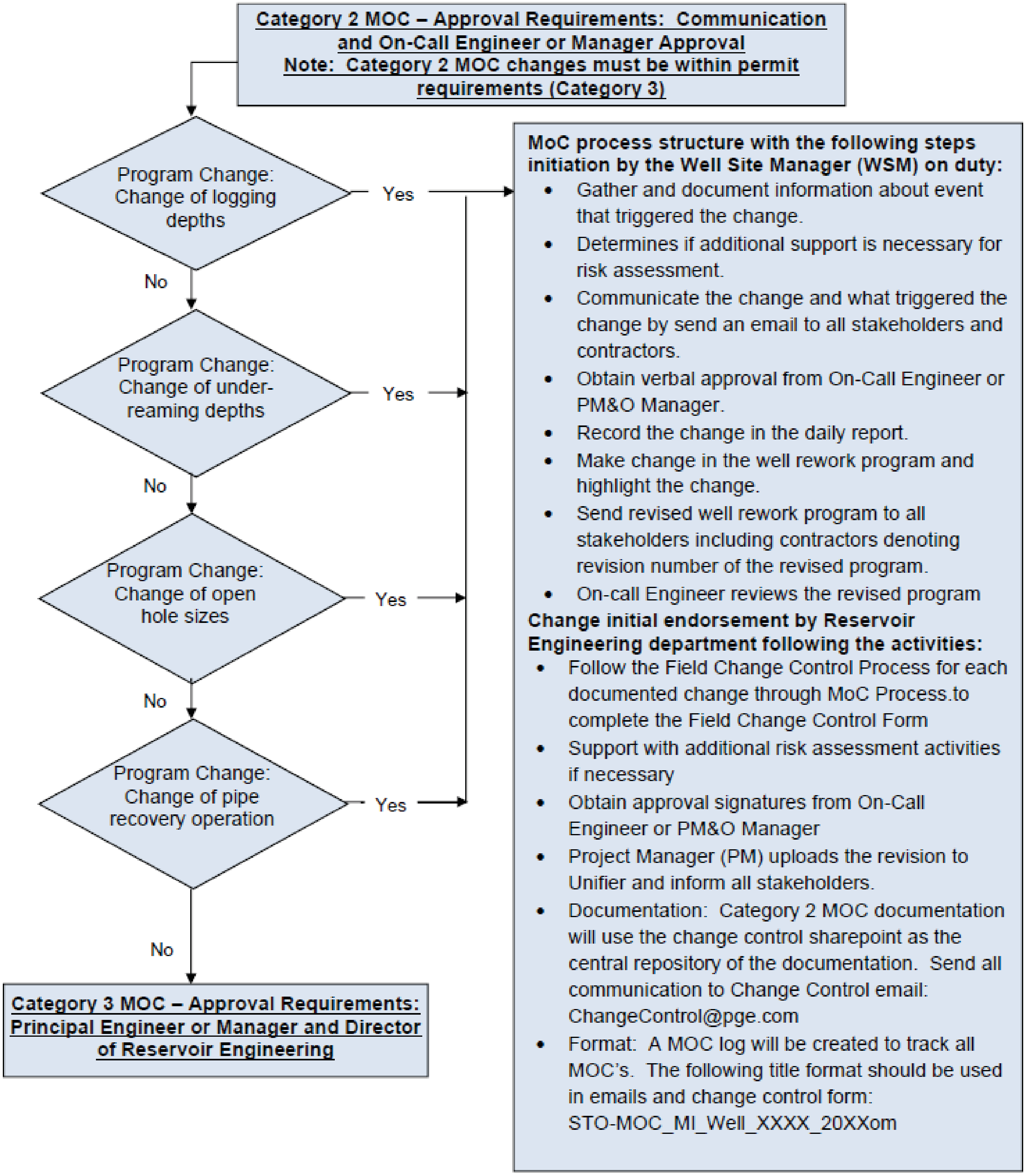


Figure AC-2: Category 2 MOC Decision Flow Chart

Category 3 MOC – Approval Requirements: Principal Engineer or Manager and Director of Reservoir Engineering

Director of Reservoir Engineering may designate authority to other individuals for Category 3 MOC Principal Engineer or Manager Approval or other approvals.

Certain event and/or step changes require MOC approval during well rework operation, such as:

1) Changes that impact permits
2) Change of production casing setting depths during cementing
3) Change of production liner packer setting depths
4) Sidetrack
5) Abandon
6) Unplanned plug-back
7) Pipe or wireline stuck in the hole that requires backing or shooting off tools

These type events changes will follow a Category 3 MoC process structure with the following steps:

A. Initiation by the WSM, Reservoir Specialist or Engineer on duty.

- Provide information about event that triggered the change
- Determines if additional support is necessary for initial risk assessment.
- Document the initial risk assessment.

B. Change initial endorsement by Reservoir Engineering department following the activities:

- Follow the Field Change Control Process for each documented change through MoC Process to complete the Field Change Control Form and document all actions triggered by the change. (see attached Form TD-4014P-01-F01, "Field Change Control Form", and Utility Procedure TD-4014P-01 for reference.)
- Support with additional risk assessment activities if necessary
- Track changes through MoC process during rework/drilling operation
- Designate PM&O Reservoir Engineer and Integrity Management Reservoir Engineer as approvers in the approval process to endorse the initial change.

C. Final approval (endorsement) by Principal Engineer or Director Reservoir Engineering.

- Inform and consult Principal Engineer or Director of Reservoir Engineering for approval process
- Challenges, provide resources for change process, approves the change before the change is implemented.

D. Communicate change and train affected Personnel by Principal Engineer and on duty personnel.

- Inform stockholders about the change by email.
- Project Manager (PM) uploads the approved revision to Unifier and inform all stakeholders.
- Train personnel, if necessary, affected by the change and document training records.

- If necessary, a PSSR can be performed if startup will be necessary.

E. Track and maintain documentation, measure effectiveness of the change by Reservoir Engineering Department.

- Track and review the effectiveness of the changes during annual critique meetings.
- Documentation: Category 3 MOC documentation will use the change control sharepoint as the central repository of the documentation. Send all communication to Change Control email: ChangeControl@pge.com
- Format: A MOC log will be created to track all MOC's. The following title format should be used in emails and change control form: STO-MOC_MI_Well_XXXX_20XX.
- Maintain a MOC log and a MOC action list log.
- Audit the MOC process on an annual basis.

Underground Storage Risk and Integrity Management Plan

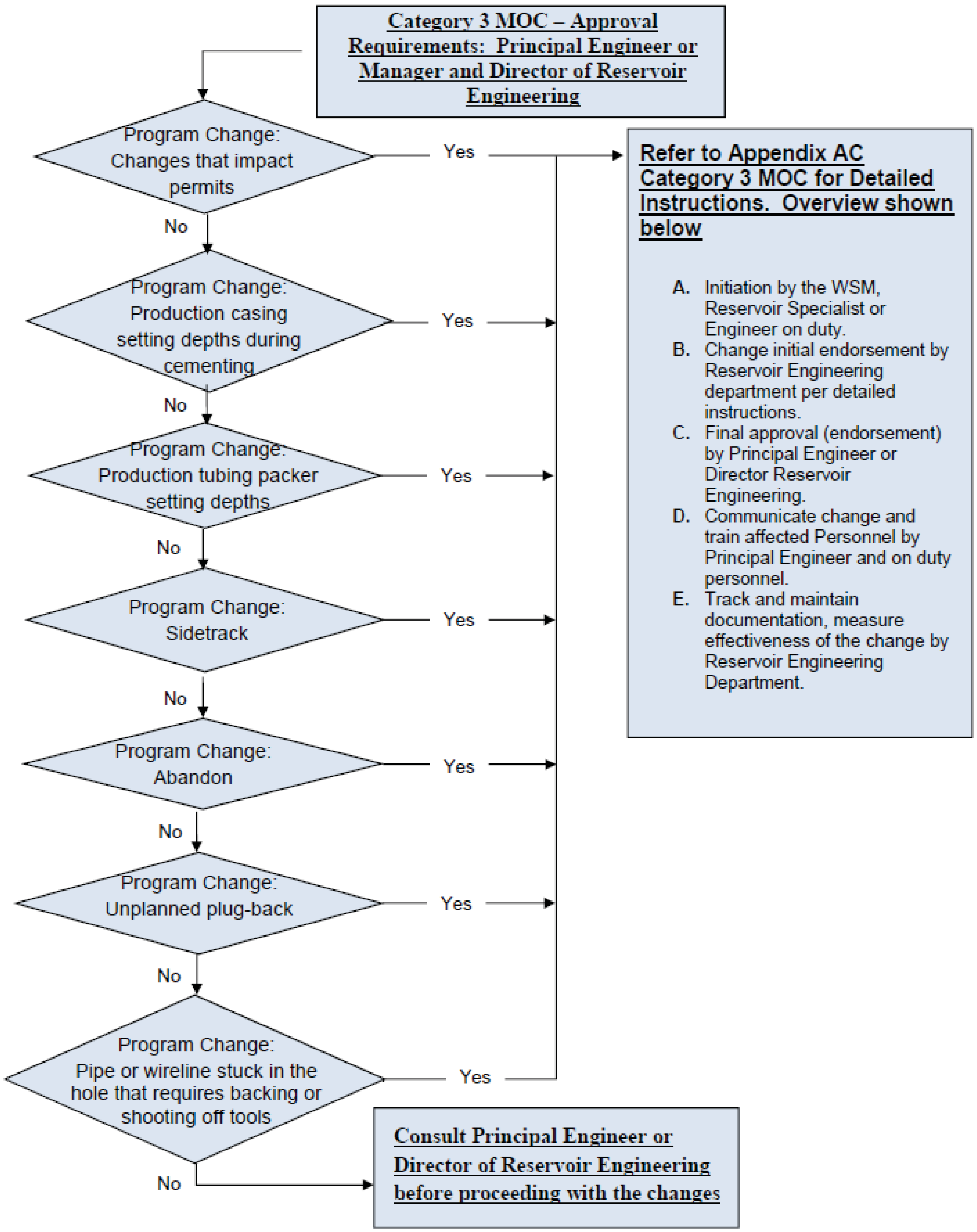


Figure AC-3: Category 3 MOC Decision Flow Chart

Appendix AD, Rig Evacuation Procedure

Procedure Step	Responsible Personnel
1. Set tool joint at rig floor & set slips	Driller & floor hands
2. Install full opening valve & close valve	Driller & floor hands
3. Shut in well with pipe rams & lock down rams a. Shut in well with blind rams if no pipe in hole b. Count the number of turns of both shafts and report it to the driller. c. Leave accumulator handle in the closed position	Derrick man
4. Secure all wing valves on mud cross & tree	Derrick man
5. Secure rig blocks	Driller
6. Shut down Draw works, Light plant & Pump	Driller & Derrick man
7. Evacuate all personal to muster station	

TWO LONG BLASTS = EVACUATION ALARM

Appendix AE, PG&E Underground Storage Facility Drilling/Rework Safety and Environmental Plan

I have reviewed and understand the Pacific Gas and Electric Underground Storage Facility Drilling/Rework Safety and Environmental Plan.

Signature:______________________Date:_______________

Prior to starting any work, all personnel must read and sign the Site Safety Plan located at the PG&E job trailer.

Personal Protective Equipment (PPE) required at all times while on jobsite.

- Hard hats
- Orange vests with reflective stripes
  - Not required while performing work on the rig floor.
- Appropriate clothing with Long sleeves
  - Coveralls with long sleeves and reflective stripes will be accepted in lieu of orange vests and long sleeve shirts. The FR is Federal OSHA requirement.
- Safety glasses
- Appropriate hearing, hand, and foot protection

Drilling/Rework Safety Requirements

- Attend site safety plan reviews and/or tailboarding meetings while on location
- Comply with all current API, DOGGR, Federal and California State and local OSHA safety regulations covering drilling rig, transportation, and equipment operations. (Contractors refer to your companies for these regulations.)
- Abide to the Injury and Illness Prevention Program as specified in the current Federal, California State and Local OSHA safety regulations. (Contractors refer to your companies for these regulations.)
- Worksites shall be kept clean and orderly at all times.

- Contractor shall inspect his/her personnel, equipment, and work site daily, and eliminate all Federal and California State and Local OSHA or DOGGR regulation violations, or any hazards that threaten the safety of personnel or well drilling and rework operations.
- Blow out preventer (BOP) drills will be performed minimum once a week per crew, or right before drill out casing shoe, or as directed by PG&E representative(s).
- All work areas shall be adequately illuminated.
- Smoking permitted in Doghouse and Contractor's trailers only. Properly dispose of butts.
- All piping on storage racks shall be chocked or wedged, or otherwise secured to prevent it from falling or rolling off the rack.
- No "piggy-back" riding on forklifts or back of pick-up trucks at any time.
- Designated parking for rig crew will be provided.
- NO PARKING on the grass or off the roadway.
- The road speed limit is 15 mph. 5 mph on the job site.
- Be mindful of cattle in the area.
- **Cell Phone use <u>not allowed</u> on the rig floor or around the wells.**
- Report any unsafe situations to Contractor supervisor and PG&E representative immediately.

Environmental Requirements

- Attend environmental plan reviews and/or tailboarding meetings while on location
- Contractors shall comply with all Federal and California State and Local EPA environmental regulations pertaining to notification, handling, storage, disposal, and transport of all hazardous or toxic substances.
- Endangered Species may be present in the area. Notify the PGE Rep immediately if any of the species is thought to be present. Photos will be provided for the work site.
- All spilled materials or liquids shall be contained and cleaned up immediately. Notify PG&E immediately of any spills.
- No fluids allowed on the ground. All leaks shall be repaired immediately.
- All service equipment shall be placed on top of plastic sheeting if there is potential for leaks or spills.
- Hazardous checks shall be made daily, by the drilling company. Correct any deficiencies immediately. Provide the PG&E representative with a daily check list.
- All hazardous <u>materials</u> shall be properly stored and containers properly labeled and maintained.
- All hazardous <u>waste</u> shall be properly stored and containers properly labeled and maintained.
- Weekly hazardous checklist shall be maintained, by the drilling company, with copies provided to PG&E.

Housekeeping

- An Emergency Contact List will be posted at the Dog House and the PG&E job trailer.
- Directions to the nearest hospital will be available at the Dog House and the PG&E job trailer.
- Sign in at the Tool Pusher trailer before working and sign out before leaving.
- <u>In case of an emergency or evacuation all personnel will meet at the McDonald Island entrance gate.</u>

Appendix AF, PG&E Underground Storage Facility Signage

General requirements of signage:

1. Posted in a conspicuous place
2. Must be clearly visible and legible from a distance
3. Recommended they not be fixed to wellhead to prevent bird nesting – There is no regulatory requirement they have to be on the wellhead

Information required on signage if placed at a single well site (can be located on security fence or near wellhead)

1. Storage facility name
2. Lease/ well name, and identification number
3. Operator name
4. Operator's 24-hour emergency contact number

Information required on signage if placed at well sites with multiple wells

1. Signage Placed on security fence at entrance (information common to all wells)
    a. Storage facility name
    b. Operator name
    c. Operator's 24-hour emergency contact number
    d. Lease/ well name if similar for all wells on pad

2. Signage placement near wellhead
    a. Lease/ well name (if differing for each well on pad)
    b. Identification number

Regulatory Requirements

PHMSA requirements under 49 CFR 192.12 (API RP 1171 Section 10.4):

Permanent weatherproof signage shall be posted at each well site for identification purposes. The signs should contain the following information at a minimum

a) Storage facility name, well name, and /or identification number
b) Operator name
c) Operator's 24-hour emergency contact number

Underground Storage Risk and Integrity Management Plan

DOGGR requirements: 1722.1.1. Well and Operator Identification

a) Each well location shall have posted in a conspicuous place a clearly visible, legible, permanently affixed sign with the name of the operator, name or number of the lease, and number of the well. These signs shall be maintained on the premises from the time drilling operations cease until the well is plugged and abandoned.

Other References:

- Gas Standard L-26, Underground Gas Storage Caution Sign
- Gas Standard L-51, Padlock Installation

Underground Storage Risk and Integrity Management Plan

Appendix AG, Well Work

Work plans shall be created when performing rework, wireline, slickline and logging operations, well testing and other well operations requiring well entry. Work plans incorporate PG&E practices set forth in this IMP.

1. General requirements:

The work plan for a specific well identifies site-specific requirements, and accounts for hazards and conditions expected to be encountered in the well.

PG&E GSAM, GPOM, Gas Contractor Safety Program Management (GCSPM), and Environmental:

1. Provide copies of appropriate guidance documentation to contractors, review those procedures with contractors prior to any work being performed, and ensure that persons performing work in the storage field are familiar with the procedures and record keeping requirements.
2. Provide training to contracted personnel that includes applicable site-specific safety procedures, awareness of rules pertaining to the facility, reporting requirements and the applicable provisions of emergency action plans.
3. Supervisor Span of Control: Confirm with contractor supervisor that supervisor is responsible for training and confirming that
    a. contractor personnel on site can recognize abnormal operating conditions, applicable hazards and know their role in safety and emergency procedures.
    b. contractor personnel conducting gas storage well and reservoir operations are qualified to perform the work.
4. Conduct inspections of adjacent active and plugged wells during or following well work to verify integrity maintenance when a well located within the reservoir area and buffer zone is being treated at pressures exceeding maximum storage reservoir pressure.

Content for this is included in the balance of this appendix, and in the well work program documents developed to specify scope, conditions and requirements for work on each well.

2. Minimum Safety Requirements

Minimum safety requirements associated with the following shall be addressed in the well work program document:

- Surface equipment
- Pressure control equipment ratings for the maximum anticipated surface pressure to be encountered during the operation.
- Procedures and requirements to verify that equipment used for pressure control is in good operating condition and suitable for the intended operation
- Downhole operations
- Management of change processes – Refer to Section 21, Change Control
- Elements of process safety management

- Other requirements as specified by regulations and PG&E.
- The pressure rating of blowout preventers and ancillary pressure control equipment is suitable for the application.

A person who is qualified in well control, or knowledgeable, skilled and capable through experience to perform well control duties, shall be on site at the well during active drilling, completion, servicing and workover operations.

3. Well Work Program Kickoff

3.1. All Contractors on site during Well Work

Review the following with contractors who will be performing drilling, completion, servicing and other work associated with storage field welds:

- well work project/program scope
- personnel, positions, roles and responsibilities within PG&E that are relevant to the well work. This includes PG&E on call and contact information.
- information specific to the facility such as evacuation plans, communication plans with the control room and PG&E
- safety procedures and issues associated with the work scope and the site that have been verified to minimize safety risks, including
  - contractor job safety analysis (JSA)
  - requirement for contractor site safety plan review and approval in advance of commencement of work
  - road operating rules
  - smoking rules
  - phone use rules
  - hot work permit
  - evacuation plans
  - PG&E's process for periodic inspection on site by PG&E safety SMEs of contractor activities
- environmental procedures and issues associated with the work scope of the site that have been verified to minimize environmental risks, and PG&E's process for periodic inspection on site by PGD environmental SMEs of contractor activities
- communication and reporting requirements including
  - communication channel procedures (e.g., well work contractor to PG&E site lead to facility control room, use of UNIFIER document application)
  - daily briefings of work plans with the PG&E site lead

    - Incidents and abnormal operating conditions (IMP Section 18, Abnormal Operating Conditions)
- management of change procedures (IMP Section 21, Change Management) including approval of deviations from the procedures when necessitated by abnormal/emergency conditions.
- requirements for training records for contractor personnel (IMP Appendix AH)

3.2. Well Entry Work Contractor Additions

Review the following with contractors who will be involved in well entry work including rework, wireline, slickline and logging operations

- well configuration and completion details;
- characterization of the stored hydrocarbons and the presence of hydrogen sulfide or other hazardous or corrosive agents;
- anticipated wellbore and storage zone pressures and temperatures;
- anticipated presence of water, fluids, deposits or scale and restrictions in the wellbore;
- reporting requirements, including that contractor personnel understand and adhere to reporting requirements in the operator's procedures.

4. Final On-Site Review

Review the following with rig crews and contractor personnel on site before the commencement of work:

- confirm that the contractor participated in the kickoff session(s) (Section 3 immediately above)
- site-specific safety plan including JSA (job safety analysis created by the contractor and signed by all personnel prior to commencement of work by that person)
- workover plans and work scope
- wellbore entry plan
- lockout tag out (LOTO) procedures employed by PG&E on-site, and training delivered by PG&E Gas Contractor Safety Program Management.
- Abnormal operating condition notification and documentation.
    - Contractors must notify GCSPM of the all incidents or injuries immediately. Notification must occur to both WSM and GCSPM and a follow up report must be received within 24 hours of the incident.
    - AOCs in general are to be documented in the daily well work report by the well site manager.
- requirements for daily tailboard
- requirement for the well site manager to provide a daily report to GSAM, including AOCs

- review and confirmation that PG&E has assessed the qualifications of the contractors' lead personnel involved in and around well entry work
- facility evacuation procedures
- rig evacuation procedures
- communication protocol between contractors, site lead and facility control room

5. Well Work Program Document

This document describes conditions, objectives, procedures and cautions relative to work planned for a specific well. It is created for each well work project by GSAM Reservoir Engineering.

Include the following in the well work program/plan document.

- Well work plans and work scope
- Pressure rating of blowout preventers and ancillary pressure control equipment
- Requirement for verification and documentation that blowout preventers are in good working condition and have been tested after installation
- Requirement for the constant confirmation that the blowout preventer position or state is as it should be at all times during the work.
- Site-specific requirements and plan elements that account for hazards and conditions expected to be encountered in the well.
- Explanations and procedures associated with operating conditions and activities where pressure control equipment is required.

Recent well work program documents developed by GSAM SMEs are valuable templates for the preparation of new well work program documents, and shall be reviewed when developing new well work program documents.

Well work program documents shall receive technical peer review from a GSAM SME prior to finalization.

Underground Storage Risk and Integrity Management Plan

Appendix AH, Well Work Contractor Competency

This appendix contains PG&E's policies and procedures that address requirements in the PHMSA IFR regarding the competency of contractors engaged in well work for PG&E.

1. Pre-Work Procedures

In advance of performing work on PG&E storage field wells, the following processes are employed to ensure contractor competency.

1.1. Contractor safety performance record

PG&E Contractor Safety Program: This work is covered within the scope of PG&E's enterprise contractor safety program as outlined in the Contractor Safety Standard, SAFE-3001S. Prior to contracting with service providers for well work, perform a review of the contractor safety record and confirm that contractor meets PG&E's qualification requirements.

1.2. Contractor technical capabilities

GSAM: Prior to contracting with service providers for well related work, perform an assessment of the technical capabilities of the contractor relative to the GSAM scope of work. This may include

a. review and assessment of prior GSAM experience with contractor.
b. discussion and assessment with other clients of contractor regarding past work performed by the contractor.
c. Review and assessment of contractor corporate and personnel qualifications (see Section 1.1.3 below)

Perform assessments with respect to the following criteria. GSAM SMEs with GSAM director approval may vary from this criteria:

a. Minimum experience performing applicable work in the gas well industry.
b. Widely recognized by gas well operator SMEs as a competent service provider, as determined by GSAM SMEs during interaction with other operators.

Criteria used will vary based on work scope, and shall be documented by GSAM as part of this assessment.

GSAM SMEs and project managers: Document assessments performed of contractor capabilities in the job file.

Once such assessments are performed, GSAM may exercise discretion regarding whether or not to perform supplemental assessments when the contractor is considered for work in the future. Document the decision in the job file.

1.4. Contractor personnel qualifications and experience

GSAM SMEs and project managers:

Prior to contracting with service providers for well related work, perform an assessment of the resumes (training, work experience, achievements) of key personnel for the GSAM project scope of work. This may include

- Discussions with key personnel regarding their work experience and capabilities.
- Review and assessment of contractor job descriptions and competency criteria for the positions under consideration.

Perform assessments of key contractor personnel such as well work contractor operations manager, blowout prevention equipment operator, and well site manager with respect to the following criteria. GSAM SMEs with GSAM director approval may vary from this criteria:

a. Minimum experience performing applicable work in the gas well industry, including well work and will control procedures.
b. Technical education/training relative to competency in the GSAM work scope.

Criteria used will vary based on work scope, and shall be documented by GSAM as part of this assessment.

Document assessments performed of contractor capabilities in GSAM shared drive “Contractor” folder under the relevant rework program year. Corresponding conclusions are documented in EDRS by the GSAM project managers and routed for approval through the director of GSAM, as applicable.

Once such assessments are performed, GSAM may exercise discretion regarding whether or not to perform supplemental assessments when the contractor employee is considered for work in the future. Document the decision in the GSAM shared drive “Contractor” folder under the relevant rework program year.

1.5. Contractor personnel training program

GSAM:

Prior to contracting with service providers for well related work, perform an assessment of the training program and curriculum in place for personnel to be employed by the contractor. Confirm that the training program content is satisfactory for the GSAM work scope. Criteria used will vary based on work scope and shall be documented by GSAM as part of this assessment.

Document assessments performed of contractor training program in the job file.

Once such assessments are performed, GSAM may exercise discretion regarding whether or not to perform supplemental assessments when the contractor is considered for work in the future.

1.6. Contractor personnel training documentation

GSAM:

Prior to contracting with service providers for well related work, GSAM may choose to obtain and assess documentation for training of personnel planned to be involved in the GSAM work scope, to confirm the appropriate contractor training has been delivered.

Decide for each contractor whether to include requirements in contract terms that the contractor must provide to GSAM a roster of all personnel expected to be on site, and training records for all such personnel. These requirements may include the following:

- Training records for personnel who have been identified by contractor in advance of commencement of work are to be provided by the contractor to GSAM prior to commencement of work.
- Training records for personnel who begin work on PG&E's jobsite after the initial commencement of work shall be delivered to the GSAM well site work manager (GSAM personnel or contract well site work manager) prior to commencement of work by that employee, along with an updated contract personnel roster.
- Records for contract personnel who begin work while the well site manager is unavailable (e.g., shiftwork in the middle of the night when the well site manager is not on site) shall be delivered along with an updated contract personnel roster by the contractor to the well site manager the following day when the well site manager becomes available. Contractor operations manager and the site lead are not allowed to commence work in this manner, and instead must be reviewed and approved through discussion and/or resume/training records by GSAM in advance of commencement of their work.
- PG&E's well site manager will assess the training records once received, but will rely on the contractor to be responsible that the personnel provided by the contractor for work on PG&E site have received appropriate training under the contractor's training program.

ON-THE-JOB TRAINING EXCEPTION - Contractor personnel who are receiving training while working on the job will be accepted without the advance training and corresponding records described above, as long as such personnel are working under the direct supervision of the contractor well work lead already approved by GSAM.

Document GSAM assessments performed of contractor training records in the job file. Retain contractor personnel training records provided by the contractor in the GSAM shared drive “Contractor” folder under the relevant rework program year.

GSAM may elect to perform supplemental assessments of training records for personnel previously assessed by GSAM when the contractor is considered for work in the future.

1.7. Contractor Site Safety Plan Review

The contractor submits a site safety plan to the well work project management or directly to PG&E’s Gas Contractor Safety Program Management (GCSPM).

GSAM: Perform a review and assessment in conjunction with GCSPM. Upon review and approval by both project management and GCSPM, the plan document is retained by the contractor and by GCSPM on site.

1.8. Contractor drug and alcohol testing program

PG&E contract general conditions require that contractors comply with PG&E's drug and alcohol abuse and testing policies, set forth in PG&E's contract general conditions.

2. Procedures during Well Work

Employ the following procedures during the performance of work on PG&E storage field wells to support ensuring contractor competency.

2.1. PG&E site and job specific training.

PG&E Gas Contractor Safety Program Management (GCSPM), GPOM and GSAM:

Conduct an orientation kickoff meeting on site in advance of the commencement of work addressing safety and work scope. A written script/checklist is used to confirm all issues are covered. This includes

- Pre-startup safety review (PSSR) led by either GSAM or GCSPM. PSSR document is retained by GCSPM in the GSAM SharePoint file.
- Training regarding notification processes and circumstances for communications with on-site GPOM control room personnel (communication path is
  - from the contractor's well work lead to the PG&E site manager to the storage field control room, or
  - from the contractor's well work lead to the contract site manager to GSAM to the storage field control room
- Lockout/tag out awareness training is provided through GAS-0867 and training delivered by GCSPM.
- Abnormal operating condition awareness. Ensure that responsibilities are clear that supervisors of well work must confirm that personnel on site can recognize abnormal operating conditions, applicable hazards and know their role in safety and emergency procedures.
- Abnormal operating condition notification and documentation. Contractors must notify GCSPM of the all incidents or injuries immediately. Notification must occur to both WSM and GCSPM and follow up report must be received with 24 hours of the incident.
- Rig evacuation procedure (Appendix AD of GSAM IMP).
- Facility evacuation guidance document.
- Project technical work scope kickoff briefing (GSAM project work plan),
- Applicability of well work management of change (GSAM IMP Appendix AC, Gas Storage Asset Management - Change Control for Well Rework Process).

Documentation that this training occurred is retained by GPOM in the project file or by GCSPM in its project files.

Any contractor personnel new to the site who have not gone through this training shall be given a job safety assessment (JSA) by the contractor prior to commencement of work by that individual.

2.2. Contract personnel identification/records.

Contractor is required to provide a personnel roster in advance of commencement of work.

When new contractor personnel are brought on site by the contractor, they become part of the roster when they sign in when they are briefed on the JSA, and training records are delivered by the contractor to the site lead as described in Section 1.1.5 above.

GSAM: PG&E or contract personnel with site lead responsibilities shall confirm that contractor training records are in GSAM's files on site for the contractor personnel on the roster provided by the contractor, or that the new personnel are receiving OJT and have no training records. PG&E shall rely on the contractor to keep the contractor personnel roster held by the PG&E site lead current.

2.3. Technical peer review of contract personnel technical performance.

GSAM: Conduct periodic inspections of contractor well related work from time to time to assess the competency of contractor personnel in the performance of GSAM's work scope, abnormal operating conditions encountered or possible, as well as the understanding of the GPOM site safety procedures including control room interaction. Assess the contractor work quality, personnel competency and the implications on the frequency of periodic inspections, and vary the inspection frequency accordingly.

Inspections and assessments performed of contractor capabilities shall be documented by GSAM in the job file.

2.4. Technical peer review of contract personnel environmental performance.

PG&E Environmental Management Department: Conduct periodic inspections of contractor well related work to assess the competency of contractor personnel in the adherence to environmental requirements associated with GSAM's work scope, in accordance with Environmental Services procedure ENV-10000S Environmental Release to Construction (ERTC) for Land and Environmental Evaluations.

Inspections and assessments performed of contractor capabilities shall be documented Salesforce, the electronic records system used by PG&E Environmental Management.

2.5. Technical peer review of contract personnel safety performance.

GCSPM: - Conduct inspections of contractor well related work to assess the competency of contractor personnel in the adherence to safety requirements associated with GSAM's work scope. This includes:

- Conduct daily observations (sometimes with a contract inspector) and document observations in “IAuditor”, the electronic tool used by GCSPM for capturing such documentation.

- Provide observations to contractor by email.
- Provide weekly report on observations including an overall summary of what was observed that week, and whether open issues need to be addressed.
- Conduct a modified PSSR developed with Process Safety Department, as an inspection once the rig in place before fluid is introduced. Document in the IA tool.
- Conduct a modified PSSR developed with Process Safety Department, as an inspection for flaring operations. Document in the IA tool.

Underground Storage Risk and Integrity Management Plan

Appendix AI, Rathole Drilling Program

Purpose:

Provide a storage place for the kelly, consisting of an opening in the rig floor fitted with a piece of casing with an internal diameter larger than the outside diameter of the kelly, but less than that of the upper kelly valve so that the kelly may be lowered into the rathole until the upper kelly valve rests on the top of the piece of casing. This hole is in the floor of the rig, bored into the earth for a short ways, and usually lined with a metal casing known as a scabbard.

Ownership:

PG&E Reservoir Engineering, PG&E Well Rework Supervisor, PG&E District/GC personnel, Drilling Rig Representative and Rathole Drilling contractor are all responsible for pre-job planning, safety meeting, and assigning personnel to perform rathole drilling execution and monitoring functions.

Actions:

The following actions are typically utilized for the PG&E gas storage rework “Rathole Drilling” operation.

1. Rework well has been cleared and flow arms removed.
2. At least 14-20 days prior to drilling rathole, PG&E Reservoir Engineering, PG&E District personnel, drilling rig representative and rathole drilling contractor will meet onsite to discuss and mark rathole location.
3. Rathole drilling contractor will make USA (Underground Service Alert) notifications.
4. PG&E Reservoir Engineering will notify drilling mud contractor and vacuum truck service to have sufficient drilling mud on site for rathole drilling to support this program. (McDonald Island only)
5. Ensure weather, and environmental conditions are appropriate before initiating Rathole Drilling Program. If not, postpone until they are favorable.
6. Hold a pre-job Safety Tailboard on this subject.
7. Ensure PG&E Reservoir Engineering, PG&E District standby personnel, drilling rig representative and rathole drilling contractor are all in agreement that the location is acceptable before attempting to drill rathole.
8. Obtain hot work permit.
9. Pothole location to a depth not less than 6’ deep (refer to TD-44412P-05 section 6.0 Critical Facility).
10. Rig up rathole drilling contractor.
11. Commence drilling rathole and adding drilling mud as needed to keep the hole lubricated and from caving in.
12. Install scabbard (metal casing) after proper depth is reached.
13. Rig out rathole drilling contractor.

14. After completion of rathole drilling GC is to clean and remove drilling spoils from the area, cover rathole and barricade the area.
15. Rathole drilling program complete.

Underground Storage Risk and Integrity Management Plan

Appendix AJ, Well Kill Program

PURPOSE

This document provides an overview of the well kill operation which is the first step in reworking a producing well. The well kill operation is the process to pump kill fluid of sufficient weight to eliminate formation pressure and allow for wellbore intervention operations to proceed. The primary method for killing the producing well for well rework operation is through its production tubing as described in the steps noted in this document.

Proper considerations must be given to the selection and type of kill fluid, formation characteristics and pressure, tubing and casing integrity, and the ability to circulate when selecting an appropriate method of killing a well.

TARGET AUDIENCE:

Reservoir Engineering, PG&E Well Site Supervisor, PG&E Gas Construction Team, Drilling Rig Supervisor and Team, and other Contract personnel. All entities are responsible for pre-job planning, safety meetings, and assigning personnel to perform the execution and monitoring functions of this program.

Updates to this program may be necessary due to changes in Facility, Operational needs or permit requirements.

ACTIONS:

Before performing the following steps, certain actions must be taken to ensure the well kill is performed in the safest and most efficient manner possible. The following actions are typically utilized for PG&E Gas Storage "Well Kill" Operation.

1. BEFORE THE START OF A WELL KILL

PG&E Well Site Supervisor has the overall responsibility for the completion of the following tasks:

a. NOTIFY Operations Department to initiate flaring notifications request at least 24 hrs before flaring / venting.

b. CONFIRM with Operations that the flaring notifications have been made. IF there is a change in date, provide Operations with advance notice.

c. HOLD Pre-Job Safety Tailboard on well kill operation.

d. INPUT Rework Well Data for Kill Calculation. Refer to Well Kill spreadsheet.

e. Record Rework Well Shut in Tubing and Casing Pressures.

f. ENSURE weather and environmental conditions are appropriate before initiating Well Kill. IF not, postpone until the conditions are favorable.

g. ENSURE sufficient volume of kill fluid is on site to support well kill operation.

h. CONSULT with engineering team regarding field conditions (i.e. low pressure) if appropriate mix materials are required to be on site to increase mud viscosity should a pill be needed during the kill operation.

i. Fill rig pits with kill fluid. Mud Engineer and Rig Supervisor to confirm that the kill fluid in the rig pits meets all specifications.

j. NOTIFY Operations to check the flaring area at least 4 hrs prior to flaring/venting and issue Hot Work Permit.

k. INSPECT that all piping connections, fittings and valves are tightened and it good condition.

l. PG&E Gas Construction (GC) and Drilling Rig Personnel are responsible for the tasks involved under supervision. GC to run temporary 2" gas (high pressure) piping from rework well casing wing valve to the PG&E Kill Manifold and Contracted permitted Flare/Separator Equipment, Half-Round, and Rig Pits.

m. ***Wells with DHSVs installed:*** Perform all steps.

n. ***Wells with no DHSVs installed*:** Omit the following items in Step 2(iv-viii).

2. <u>PREPARATION TO PRESSURIZE PIPING/EQUIPMENT AND TESTING</u>

a. CONNECT rig pump discharge line to the well tubing connection on the rework well.

b. ENSURE the Rig Supervisor has set up valves in the correct position from the rig pumps to the well tubing connection.

c. PRESSURE TEST rig pump discharge line between rig pumps and wellhead. Start pump and pressurize to 2000 PSIG and check for leaks. If leaks are found, make repairs and retest as necessary.

d. NOTIFY Operations to Report On "Test" on rework well.

e. INSTALL pressure gauge(s) to obtain rework well Tubing and Casing Shut-in pressures above the DHSV(s). If pressure differential between Tubing and/or Casing Shut-in pressures and Field pressure is >100 PSIG, pressures must be equalized. Ensure pressures are within acceptable (~100 psi range) before attempting to pump hydraulic fluid.

f. ENSURE air supply from drilling rig is adequate and readily available. CONNECT air hose to the pneumatic hydraulic pump air inlet.

g. CONNECT hydraulic pump hose to the DHSV connection on the rework well.

h. PUMP hydraulic fluid up to 4500 PSIG to OPEN DHSVs on the rework well. Acceptable limits are within 4000-4500 psi. VERIFY DHSVs OPENED.

i. CONTINUOUSLY MONITOR and maintain up to 4500 PSIG on the DHSV hydraulic control line.

j. Ensure all three Gate Valves are closed on the Kill Manifold.

k. ENSURE “Rework Well” wellhead valves are closed. SLOWLY OPEN casing wing valve to obtain gas pressure and check for leaks. CHECK LEAKS on all fittings and connections by SOAP TESTING.

l. PRESSURE TEST all gas piping including contractor’s permitted flare equipment between the PG&E Kill Manifold and Outlet of their separator skid. PRESSURE TEST in two steps.

m. Step 1: Test to 100 PSIG. If LEAKS are found, bleed all gas piping including contractor’s permitted flare equipment to 0 PSIG. FLARE as directed. Follow the clearance process to FIX any LEAKS before proceeding.

n. REPEAT Step 1 as necessary until all leaks have been repaired, then proceed to Step 2.

o. Step 2: Test to AVERAGE FIELD PRESSURE. RAISE Pressure in increments until it reaches average field pressure. If LEAKS are found, bleed all gas piping including contractor’s permitted flare equipment to 0 PSIG. FLARE as directed. Follow the clearance process to FIX any LEAKS before proceeding.

p. REPEAT Step 2 as necessary until all leaks have been repaired. THEN proceed to VENT ALL GAS DOWNSTREAM OF THE KILL MANIFOLD.

3. PUMPING KILL FLUID

a. INSTALL pressure gauge on the kill manifold to monitor the casing flow pressure during the well kill operation.

b. ENSURE stroke counter is set to zero and is functioning properly.

c. MONITOR rig pumps strokes per minute as initiated by Reservoir Engineering Rework Supervisor. Consult the Rig Supervisor on final number.

d. SLOWLY OPEN casing wing valve to Kill Manifold. Kill Manifold gauge should read field pressure.

e. Begin pumping kill fluid down the tubing and while simultaneously opening Master Gate Valve slowly.

f. MAINTAIN pump rate while adjusting kill manifold choke valve to bleed off casing gas pressure as per Kill Sheet.

g. When fluid reaches surface, transfer returns to the rig’s pits and continue circulating until fluid is relatively free of gas.

h. Stop pumping to verify the rework well is STATIC. Zero pressure on tubing/casing indicates well is full of kill fluid. Well is now safe to install back pressure plug.

i. Clearance can now be removed from rework gas well.

j. Well Kill operation is completed.

k. VERIFY volume and note any fluid losses.

l. ENSURE safe work practices.

Appendix AK, Well Bring-In Procedure

What & Why: Under the final regulations introduced by the Division of Oil, Gas, & Geothermal Resources (DOGGR), storage operators are required to utilize a tubing and packer completion to accomplish dual mechanical barriers.

Wells completed with a tubing and packer (T&P) configuration will require the procedural guidance below to unload and bring-in wells due to the type of downhole equipment installed in T&P wells and how the equipment achieves mechanical isolation from the reservoir. PG&E will no longer be able to “Rock the Well” in order to unload the tubing string for tubing flow only wells as historically done on wells completed with open ended tubing (i.e. tubing and casing flow wells).

Process: For wells completed with tubing and packer, gas will be used from an adjacent well to displace the fluid column in the tubing string such that the hydrostatic pressure is sufficiently reduced and allows for reservoir pressure to lift the remaining fluid.

The well specific detailed procedure is required to be included in the well work program documents. The following provides a general overview of the sequence to achieve this is as follows:

1) Land tubing string in the wellhead
2) Rig up Slickline and install XN plug, isolating string from Reservoir Pressure
3) Pressure Test tubing and tubing-casing annulus
4) Install back pressure valve & nipple down BOP
5) Nipple up production tree
6) Use Slickline to shift sliding sleeve open above packer, giving ability to circulate
7) Using Adjacent well, displace gas down tubing while taking returns from the casing valve
8) After Tubing string has equalized with adjacent well’s reservoir pressure, shut in
9) Use slickline to shift sliding sleeve closed and pull XN plug, allowing reservoir flow
10) Blow down gas and bring in well through the tubing

Underground Storage Risk and Integrity Management Plan

Appendix AL, BOP Inspection Process

PURPOSE: This document provides an overview of the inspection process of the BOP to be conducted in the field to identify any issues that would prevent the BOP from functioning or providing adequate well control during the rework process.

TARGET AUDIENCE: Reservoir Engineering, PG&E Well Site Supervisor, Drilling Rig Supervisor and Team, and other contract personnel. All entities are responsible for pre-job planning, safety meetings, and assigning personnel to perform the execution and monitoring functions of this program.

ACTIONS:
The BOP shall be fully inspected and certified by the provider prior to delivery at first well and every 90 days thereafter. In between full inspections, the following actions should be taken before nipping up the BOP to ensure all equipment is functioning safely and properly. If any issues are identified, return BOP to vendor for full inspection (refer to vendor inspection procedure provided elsewhere)

Annular BOP

1. Visually inspect the outer body for any visible damage or corrosion
2. Visually inspect the flange connections and bolts for any sign of stretch, damage or corrosion
3. Visually inspect the annular element for any apparent rubber loss or damage
4. Visually check through bore for any restrictions, washing, kelly whip or any other damage

BOP Ram Type

1. Visually inspect the outer body for any visible damage or corrosion
2. Visually inspect the flange connections and bolts for any sign of stretch, damage or corrosion
3. Visually check through bore for any restrictions, washing, kelly whip or any other damage.
4. Ensure locking shafts are exposed, unless shut in for a reason
5. Ensure pipe rams match the work string selected for the project
6. Function test rams to ensure they are working properly

Accumulator

1. Visually inspect the Accumulator, bottles and hoses for any visible damage or corrosion
2. Ensure the pressure gauges are reading the correct values
3. Ensure adequate amount of fluid in the reservoirs for full closure of all BOP elements
4. Ensure accumulator is able to charge reservoirs to necessary pressures

Pacific Gas and Electric Company

McDonald Island Underground Storage Field: Well Risk Evaluation and Construction Standard Implementation Plan

Gas Storage Asset Management Department

Publication Date: March 29, 2019

Table of Contents

1. Introduction

This plan provides the applied individual well risk assessment as detailed in PG&E's Underground Storage Risk and Integrity Management Plan and is specific to the Pleasant Creek Storage Field Facility wells. This plan is a companion document to the Underground Storage Risk and Integrity Management Plan and is intended to be used in conjunction with the preventative and mitigation (P&M) measures included in the noted plan.

Under the Interim Final Rule (effective January 2017) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and API RP 1171 incorporated by reference, operators shall develop a program to manage risk that includes a process to assess risk related to the storage operation on a consistent basis. Additionally, under the Final Regulations (effective October 2018) issued by Division of Oil, Gas, and Geothermal Resources (DOGGR) require operators to perform a risk assessment on a well-by-well basis (§1726.3(c)(2)(4)).

Contained within this implementation plan is the planned schedule to convert PG&E's storage wells at Pleasant Creek to conform with the construction requirements of dual barriers required in Final Regulations (effective October 2018) issued by Division of Oil, Gas, and Geothermal Resources (DOGGR).

Lastly, this plan provides the performance based reassessment methodology and plan for wells following baseline and subsequent inspections.

2. Relative Risk Well Model Approach and Data Sources

Individual well-by-well risk ranking allows PG&E to manage P&M programs to adequately address highest risk assets and prioritize capital projects accordingly. The relative risk ranking model database manages and tracks the inputs, both static and dynamic, to evaluate the relative risk of each well.

Continuous Evaluation (CE) is used to evaluate the integrity of each well based on data integration from both integrity assessments performed and routine maintenance, operations, and testing performed to evaluate asset condition and subsequent risk profile. Data collected from the P&M measures are used to inform the scoring assignments. Additionally, baseline casing assessment and reinspection data are input into the model. Reinspection frequency is based on the Underground Storage Risk and Integrity Management Plan, Appendix C – Casing Inspection Survey Frequency Tree.

2.1. Roles and Responsibilities

Reservoir Engineering is responsible for analyzing all the available asset data collected in the practices outlined in the Underground Storage Risk & Integrity Management Plan to evaluate the overall condition and exposure of each well asset.

2.2. Publication Schedule of the Relative Risk Model

The model is maintained throughout the year as new data becomes available and the following schedule guides the formal publication/snapshot of the relative risk model.

Publication	Purpose
By July 31	Identifies/confirms well population scheduled for next two-year rework cycles
By January 31	Integrates previous season rework Integrates year end data to identify any emergent or break in work to be addressed in the coming year and confirms five-year outlook

2.3. Relative Risk Model Attributes Inputs

The following sections below outline the various attributes and inputs that are considered in the relative risk ranking analysis. The data includes both static and dynamic data; static data is unchanging and does not require annual review, whereas dynamic data is dependent on testing result inputs.

The risk score for each well is computed by summing the score components that impact likelihood of loss of containment and multiplying that value by the sum of the consequence score impacts to safety, environment, and reliability.

Likelihood Score Components	Consequence Score Components
• Usage Factor • Adjusted Rework Factor • Production Casing Condition Factor • Tubing and Packer Condition Factor • Monitoring and Inspection Condition Factor • Wellhead Security Factor • Natural Force Factor	• Well Rate Factor • Well Operation Factor • Wind Direction Impact • Proximity Factors: Occupied Structure, Offset Well, Road and Railway Proximity, Local/Adjacent Land Use, Water Proximity, Response to Well Incident • Well Configuration • Valve Factor

2.4. Likelihood Scoring Components

The likelihood scoring components include the following factors are a defined in the following subsections. The scoring component is shown in the shaded box within the section.

The scoring components are combined in the following equation:

Likelihood = (Usage Factor/5) + (Adjusted Rework Factor x 5)
+ (Production Casing Condition Factors)
+ (Tubing and Packer Condition Factors)
+ (Monitoring and Inspection Condition Factors)
+ (Well Security Factor)
+ (Natural Force Factors)

2.4.1. Usage Factor:

The usage factor is computed as described below:

- Usage Factor: This score considers the impact of the duration of use over a well's life cycle, the prospect for human error via intervention activities, how the well has been used to account for levels of stresses the well has been subject to.

$$\text{Usage Factor} = \text{Average}\left\{\begin{array}{c}\text{Number of Years in Operation}\\ \text{Years since last well rework}\\ 20 \times \text{Well Operation}\end{array}\right\}$$

  - Well Operation: The current operational state in which the well is used. Wells will be identified as Injection and withdrawal (Inj/Wd), withdrawal only (Wd only), or observation (obs). The use of the well is dependent on construction and surface facility installments. Wells that are used for both Inj/Wd have a higher likelihood score as the stresses from injection and withdrawal activities are the highest. Wells used for Wd only do not experience injection forces, thus are scored lower. Wells used of observation do not experience dynamic loading and are scored lower at a 1.

    The following likelihood scoring is given based on identified well operation:

    Injection/Withdrawal (IW) = 3

    Withdrawal only (wd only) = 2

    Observation (obs) = 1

2.4.3. Adjusted Rework Factor

This score is based on the knowledge of the casing condition and assigns a higher risk score to wells that have had intervention or rework activity and have not had a casing assessment performed. This accounts for the human impact and risk associated with rework activity, and elevates opportunities where the casing could have been impacted but the condition is unknown.

Rework Factor =	If casing condition not known	→	Number of Well Reworks
	If casing condition not known	→	0.5 x Number of Reworks

2.4.4. Production Casing/Inner String Condition Factor:

The production casing condition factor is a summation of the following inputs for the production casing string. In wells that have been converted to tubing and packer, this element is considered the secondary barrier.

- Original Production Casing Wall Thickness: This score is based on the worst-case metal loss identified in a casing inspection survey (i.e. MFL or ultrasonic). In the case where a well has not been assessed, the highest score is assigned.

  Unknown = 4
  Class 3 or 4 = 3
  Class 2 or general = 2
  Isolated Class 1 or 2 = 1

- Inner String Production Casing Wall Thickness: This score is based on the worst-case metal loss identified in a casing inspection survey (i.e. MFL or ultrasonic) where an inner string has been cemented into place. In the case where a well has not been assessed, the highest score is assigned.

  Unknown = 4
  Class 3 or 4 = 3
  Class 2 or general = 2
  Isolated Class 1 or 2 = 1

- Production Casing Wall Thickness: If an inner string is in place to remediate an original production casing, this pulls the inner string production casing identified

above. If the original production casing is still the active production casing string, this pulls the production casing from two items above.

Unknown = 4
Class 3 or 4 = 3
Class 2 or general = 2
Isolated Class 1 or 2 = 1

- Source of Metal Loss on Production Casing: This identifies the source of any known metal loss and assigns the score to metal loss due to corrosion as 3. For wells where the condition is unknown, the highest score of 4 is assigned to elevate the risk for wells where the condition is unknown.

Corrosion (IC or EC) = 5
Mechanical = 2
None = 0

- Potential Production Casing Mechanical Leak Path: This score identifies possible leak paths that could lead to a loss of containment incident based on the construction of a well or known historic leak prone connections. This score takes into account the well's construction and whether or not a potential leak path is present. Uncovered perforations, such that they have not been remediated with a scab liner to mitigate risk, are given a score of 5. Uncovered stage collars, those not proactively or in mitigation covered with a scab liner, also present a potential leak path and are assigned a 4. Stage collars that have been remediated with an inner string, while still can be a potential leak path, are considered less risky and a score of 3 is assigned. A casing thread leak is scored as a 2.

Uncovered Perforations = 5
Uncovered Stage collar or thread leak = 4
Isolated (by cement or Inner String) Stage Collar = 3
Isolated casing thread Leak = 2
None Identified/Not Applicable = 1

- Dogleg Severity: This score is based on the percentage of dogleg severity(DLS). DLS is considered as the combined stresses across sections of high deviation are higher and are also prone to greater amount of casing wear from pipe

tripping. The maximum % of DLS is considered in the risk score as a well with a section of pipe that has a high degree of DLS impacts the allowable stress limit of a well and reduces the amount of tolerable wall loss at the same performance rating.

0% -5% = 1
5% -10% = 2
> 10% = 3

- Inner String Installed: The presence of an inner string is included in the scoring as it adds risk by creating another potential leak path and additional element that requires monitoring.

Yes, Installed = 2
No = 1

- Cement Bond Log TOC: The cement bond log uses the input value from the TOC identifying the highest top of well bonded cement with relation to the surface casing shoe depth.

Full - 1
Inside SC - 2
Below SC - 3

2.4.5. Tubing & Packer Condition Factor

The tubing & packer condition factor is a summation of the following inputs:

- Tubing Wall Thickness: This score is based on the worst-case metal loss identified in an inspection survey (i.e. MFL or ultrasonic). This will only impact the score of wells that are converted to tubing and packer configuration.

Class 3 or 4 = 3
Class 2 or general = 2
Isolated Class 1 or 2 = 1
Not Applicable = 0

- Potential Tubing Mechanical Leak Path: This score is based on known thread leaks of the tubing.

Tubing thread Leak = 2
None Identified/Not Applicable = 0

- Packer Condition: This score is based on how well a packer is sealing and if a known packer leak is present.

Known Leak=2
Sealing/Not Applicable = 0

2.4.6. Monitoring and Inspection Condition Factors:

The following monitoring and inspection data points/trends are combined for each well evaluation:

- Annular Condition Monitoring Plan: This score uses the presence of an annular condition monitoring plan to elevate the risk of a given well.

  Note: based on the annular testing performed, annular pressure can be managed and is typically not considered a hazardous situation.

Yes = 3
No = 1

- Sand Production: The sand inspections of each well is typically performed twice each year during withdrawal season. This score uses the historical sand inspection data and counts the number of inspections that have been a grade 3 or higher. This elevates the risk score of a well as it can be associated with higher erosion rates and gravel pack degradation.

Count of # of Grade 3 or more that have occurred since last rework

- Gas Composition: This score takes into account the type of gas in the storage system and if corrosive constituents are present and could cause/accelerate metal loss features.

None = 0 *CO_2 = 1* *H_2S = 5*

- Wellhead Flange Condition- known leak: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2 *No= 1*

- Wellhead Tubing head Condition- known leak: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2 *No= 1*

- Wellhead Hydraulic Port Leak Condition: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2 *No= 1*

- Known Hydrate Potential: This score is factored in for wells where hydrate formation on the system has been identified historically.

Yes, historically observed = 1 *No= 0*

2.4.8. Wellhead Security Factor

The Wellhead security factor is a summation of the following inputs:

- Well Security: This score is based on security features installed at a given wellhead site or group of proximate wellheads. This score impacts the likelihood by taking into account the presence of a barrier that would limit access, thus reducing the likelihood of an external influence triggering a loss of containment event. Wells that have a fencing system are scored with a 1 and those without any type of physical barrier limiting access would be a 2.

  All of PG&E's wellhead sites are gated and fenced.

  Gated/Fenced = 1

  No= 2

- Wellhead Surface Impact Damage Protection: This score is based on security features installed at a given wellhead site to minimize opportunity for surface impact to the wellhead to occur and lead to an uncontrolled flow event. If no measures are employed, then the highest score is assigned as the wellhead has a higher risk of exposure to surface impact (i.e. vehicular). The likelihood score is reduced based on the level of surface protection provided whether a full circumferential system (i.e.. Bollards) be in place or partial (i.e. k-rail system on one side). Wells that are enclosed by a fence but do not have a barrier in place have a higher risk as maintenance vehicles drive within the fenced area.

  Full Barricade (k-rail/bollard) =1

  Partial Barricade (k-rail/bollard) = 2

  None (Fenced only) = 3

2.4.9. Natural Force Factors

The following factors are included and take into account naturally occurring outside force threats.

- Flooding: This score is based on the potential to experience flooding at a given storage facility.

  No= 0

  Yes=1

- Seismic: This score is based on the potential seismicity a given storage facility.

Low = 1
Med = 2
High =3

- Subsidence: This score consider is there is active subsidence at the facility.

No= 0
Yes=1

- Tsunami: This score considers the opportunity for a tsunami to impact the facility.

No= 0
Yes=1

- Landslide: This score considers if the facility and well site is situated where it could be impacted by landslides.

No= 0
Yes=1

2.5. Consequence Scoring Components

The consequence scoring components include the following factors as defined in the following subsections. The scoring component is shown in the shaded box within the section.

The scoring components are combined in the following equation:

$$\text{Consequence} = [\,(0.25 \times \text{Well Rate Factor}) + (\text{Well Operation Factor}) + \Sigma\,(\text{Proximity Factors})\,] - [\,5\text{x}\,(\,(0.5\ \text{Configuration}) + (\text{Valve Factor})\,)\,]$$

2.5.2. Well Rate Factor

- Rate Factor: This is based on the max current rate at the time of publishing the risk plan. Twenty-five percent of the rating factors into the consequence score to account for the reliability impact with the loss of a well.

2.5.3. Well Operation Factor

- Well Operation: The operational consequence of an event is also impacted that renders the well unusable has a greater implication on operations and use of the storage field. Withdrawal only wells carry an intermediate scoring as the unavailability of the well poses a risk to deliverability. Observation wells are assigned the lowest value in this category as unavailability would not impose a risk to operations.

Injection/Withdrawal (IW) = 3

Withdrawal only (wd only) = 2

Observation (obs) = 1

2.5.4. Proximity Factors

- Wind Direction Impact: This score looks at a well's surface location with respect to the nearest located structure and the predominant wind direction. This score is considered high such that a large release of gas could have severe impact with ignition on an adjacent facility. The score is low such that the predominant wind direction is away from adjacent structures.

High = 3

Low = 1

- Occupied Structure: This score is based on the well's surface location and its proximity to an occupied structure.

>1000 ft = 1

500-1000 ft = 2

0-500 ft = 3

- Offset Wells: This score is based on the well's surface location and its proximity to an adjacent wellhead.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Roads: This score is based on the well's surface location and its proximity to a road as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3
0-500 ft of Major Highway = 4

- Proximity to Railroads: This score is based on the well's surface location and its proximity to a railroad as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Major Airport: This score is based on the well's surface location and its proximity to a major airport as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Population Centers: This score is based on the facility’s location and the buffer rings indicated in the scoring.

> 1 Mile =3
1-2 Mile =2
2-5 Mile =1
>5 Mile = 0

- Proximity to Body of Water: This score is based on the facility's location and the buffer rings indicated in the scoring.

> > 1 Mile =3
> 1-2 Mile =2
> 2-5 Mile =1
> >5 Mile = 0

- Local Area/Land Use: This score is based on the facility's location and the surrounding area activity.

> Urban = 4
> Residential = 3
> Crop farming (Irrigation/fertilizer / Plane) = 2
> Cattle farming = 1

- Response to Well Incident: This score is based on proximity of employees to recognize and be able to respond in the event of a well emergency. Manned facilities have a higher likelihood that a response would be fairly soon after an event started or signs of an event could be recognized to minimize the impact.

> Unmanned-2
> Facility Manned-1

2.5.5. Valve Factor

This factor is used to reduce the consequence score by the mitigation employed by the presence and performance of a DHSV. The factor is computed in the following manner; each scoring component is listed and explained below.

$$\text{Valve Factor} = \left(\frac{\text{DHSV-Csg deployed}}{\text{DHSV-Csg Condition}} \right) + \left(\frac{\text{DHSV-Tbg deployed}}{\text{DHSV-Tbg Condition}} \right) + \left(\frac{1}{1 + \text{DHSV CL-cond}} \right)$$

- Well Configuration Factor: This score is used to reduce the consequence such that the dual barrier configuration would reduce the impact on the consequence.

  This score is factored by 50% in the final algorithm.

T&C Flow -1
T&P - 4

- DHSV Casing (Csg) Deployment: This score considers the presence of a DHSV on the casing side. Once wells are converted to tubing and packer, there is only a DHSV installed on the tubing side.

Yes -1
No - 0

- DHSV Tubing (Tbg) Deployment: This score considers the presence of a DHSV on the tubing side. Once wells are converted to tubing and packer, there is only a DHSV installed on the tubing side. Note: not all wells require a DHSV to be installed based on the critical well definition.

Yes -1
No - 0

- DHSV Casing (Csg) Condition: This score sums the number of level 4 leak by tests results a valve has received since installation.

# of Level 4 since installation

- DHSV Tubing (Tbg) Condition: This score sums the number of level 4 leak by tests results a valve has received since installation.

# of Level 4 since installation

- DHSV Control Line Condition: This score sums the number of level 4 leak by tests results the control line has received since installation.

# of Level 4 since installation

3. McDonald Island Construction Standard Implementation Plan

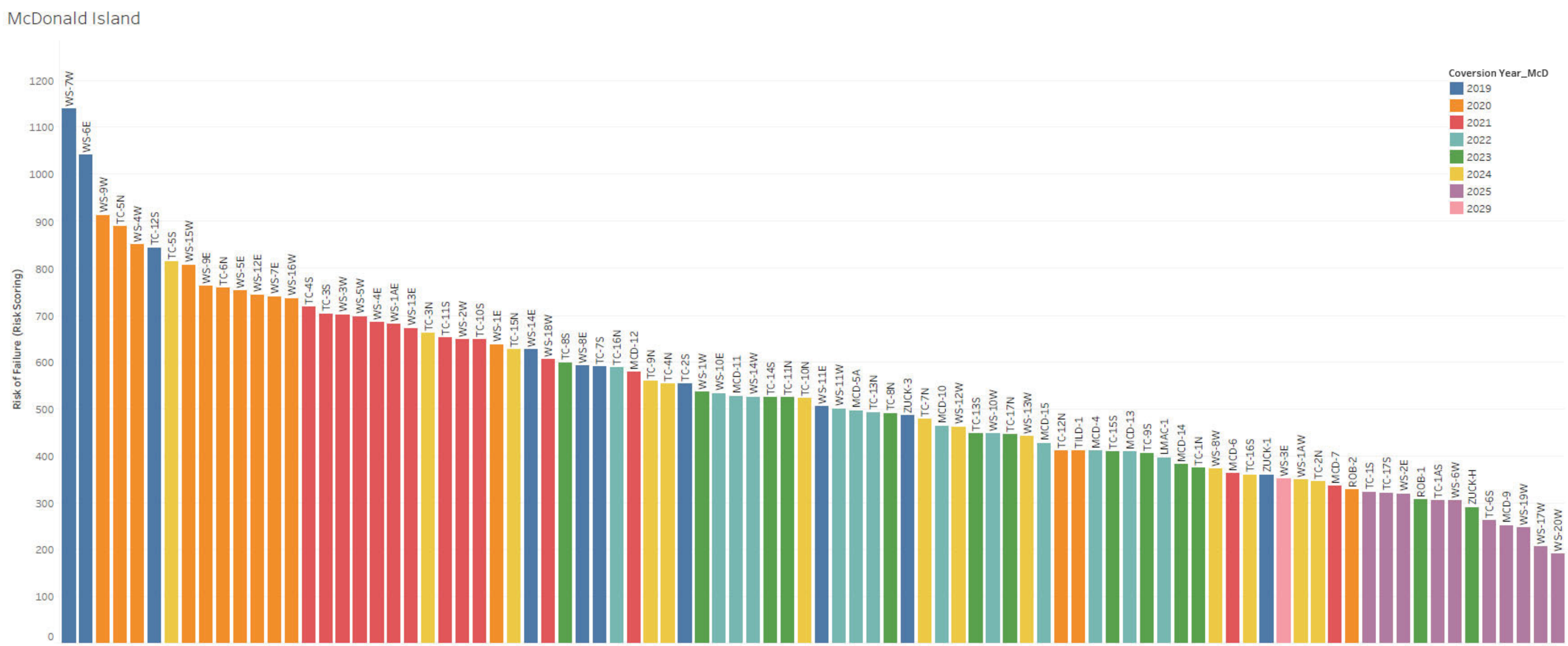
PG&E's wells located at McDonald Island are typically completed with open ended tubing and flow gas in both the tubing and casing annuli. In accordance with the construction standard in the DOGGR final regulations §1726.5, PG&E is phasing in the retrofits and/or permanent plug and abandonment as shown below in the schedule by year. Refer to the well specific schedule shown in Appendix B – McDonald Island Well Implementation and Assessment Schedule for the planned year of conversion. Additionally, Figure 3-1 shows the planned year of conversion and relative risk of a given well.

The well-by-well planned schedule is a living document and is based on the current data and inspection information known at the time this plan was published. The planned schedule is subject to change following the annual ranking update and where continuous evaluation activities necessitate advancing a well ahead of the planned date to address issues accordingly. Table 1 below shows the number of wells targeted by year to accomplish the conversion to tubing and packer configuration or plug and abandon by the end of 2025.

Table 1

McDonald Island 2019-2025 Well Construction Standard Implementation Plan			
Year	**Planned Number of Wells**	**% of Total Wells**	**Cumulative Count**
2018	0	0	1*
2019	10	11%	11
2020	14	16%	25
2021	14	16%	39
2022	13	15%	52
2023	13	15%	65
2024	13	15%	78
2025	10	11%	88
*Note: One well at McDonald Island was completed with T&P prior to the regulations.			

Figure 3-1: T&P Conversion shown by year and Risk Rank



4. Baseline and Reassessment Schedule & Methodology for Casing Inspection

PG&E commenced performing baseline inspections in 2013 and has completed a baseline casing inspection log on 35 wells (40% of field) at the start of 2019. As the program advanced, additional logs and tests were grouped into the suite of testing to establish a baseline in 2016. The suite of testing is provided in the Risk and Integrity Management Plan in Appendix Z. The status of well assessments can be grouped into three categories based on the time period when the assessment occurred:

1. **Pending Assessments:** Wells have not yet been inspected using advanced casing inspection tools. These wells have been inspected for baseline gas behind pipe using GRN tools. The wells have continued to be monitored annually via noise and temp (N&T) inspection. Additional daily and weekly monitoring activities (i.e. leak inspection and annular pressure monitoring) have been performed in alignment with the Risk and Integrity Management Plan Practices.

2. **Pre-2016 Assessments:** Wells were typically assessed using MFL tools for inspections, GRN tools during well work and also were monitored using the noise & temperature tools (N&T) annually. Additional daily and weekly monitoring activities (i.e. leak inspection and annular pressure monitoring) have been performed in alignment with the Risk and Integrity Management Plan Practices.

3. **2016-Current Assessments:** Wells were assessed using the full suite of inspections including MFL, CBL, N&T, GRN/RST, ultrasonic, caliper, and pressure testing. Additional daily and weekly monitoring activities (i.e. leak inspection and annular pressure monitoring) have been performed in alignment with the Risk and Integrity Management Plan Practices.

A key finding from the groups of wells that have casing assessment data demonstrates that current field wide conditions at McDonald Island do not appear indicate active corrosion is present. Inspection data from MFL and ultrasonic support the conclusion that neither internal or external corrosion appear to be prevalent or common at this time. PG&E uses the guidance in Appendix C of the Risk and Integrity Management Plan to determine the reinspection frequency for a given well following a baseline or reinspection of casing condition. The typical casing frequency return period continues to fall into “12-15 year” re-assessment window based on limited metal loss (class 3 and below) and isolated condition. PG&E will be returning to the well that was previously assessed for conversion to tubing and packer ahead of follow up inspection and planned reassessment period.

PG&E plans to complete the remainder of the baseline inspections at McDonald Island during the well conversion to tubing and packer configuration. PG&E uses a methodology that is prioritized by risk and coupled with the ability to effectively and efficiently conduct the work, minimization of unnecessary equipment mobilization, and coordination with station projects (i.e. pipeline work, platform equipment maintenance/rebuilds) to reduce impact to deliverability and station outage. Figure 4-1 maps this approach and uses the results of the risk model, PG&E prioritizes the wells in the based on the risk score and looks at each of the following categories:

1. **Assessment Status of "Pending**": wells pending assessment are targeted in the first group to be converted to tubing and packer configuration. During that conversion activities, wells will be inspected using the full suite of inspection tools identified in Appendix Z.

2. **Assessment Status "Pre-2016"**: wells that are slated for re-inspection following their baseline metal thickness inspection will be targeted

3. **Assessment Status "2016- Current":** These wells have been evaluated using the full suite of logs in Appendix Z. Wells in this category typically have a re-assessment internal of 12-15years and PG&E will be returning to these wells to reconfigure them in a tubing and packer status ahead of the targeted re-assessment interval.

Using this approach, all wells at McDonald Island will have had an initial baseline casing condition inspection by the end of 2023. Additionally, PG&E plans to run a thru-tubing casing inspection log on wells that are pending assessment and not planned for work in 2020. This logging activity will continue every two years until the well has been assessed. This allows PG&E to identify if any of the wells pending assessment have any features that require remediation ahead of the planned schedule and can advance those wells accordingly. Further, for wells that have been previously assessed with a casing inspection, a thru-tubing surveillance logging program will commence in 2020 and cycle every two years until the well is converted to tubing and packer. The planned cadence for each group is also show in Figure 4-1.

Following a well's baseline inspection and/or conversion to tubing and packer, PG&E will identify the well's casing reassessment frequency per Appendix C of the Risk and Integrity Management Plan. PG&E plans to deploy a casing inspection surveillance program using thru-tubing technology to monitor for any changes in condition; note, this surveillance activity is in addition to the routine integrity monitoring practice (i.e. sand inspection, pressure monitoring, annual noise and temperature survey).

Figure 4-2 illustrates the frequency of the thru-tubing inspection and pressure testing, per Appendix K of Risk and Integrity Management Plan. After the first two cycles of thru-tubing logging are performed, PG&E will space the 3rd logging activity halfway between the next planned reassessment. For example, a well scheduled on a 12-15 year reassessment interval will have a thru-tubing log run in year 2 and year 4 following conversion to T&P. The next thru-tubing log will be run in year 8, halfway between year 4 and year 12. Refer to Appendix B for additional information regarding thru-tubing logging and scheduling methodology.

Refer to Appendix B for the planned schedule based on the methodology presented above.

Figure 4-1: Assessment in Year & T&P Conversion Risk Informed Methodology

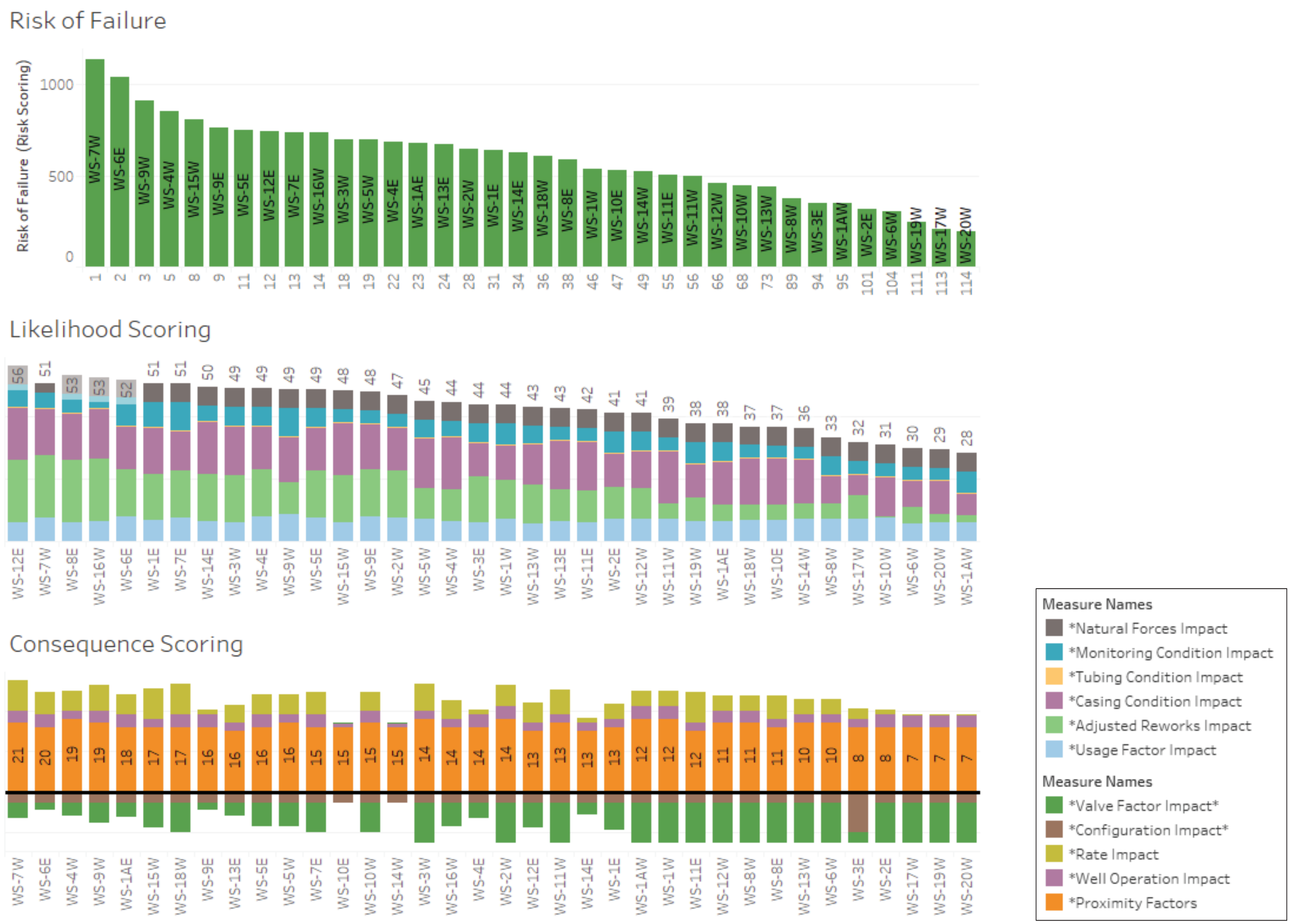
Year of Assessment	Assessment in Year & T&P Conversion						
	2019	2020	2021	2022	2023	2024	2025
Pending	2019 Planned Wells: Full Assessment with T&P Conversion						
Pending	N&T	2020 Full Assessment with T&P Conversion					
Pending	N&T Thru - Tubing	N&T	2021 Full Assessment with T&P Conversion				
Pending	N&T Thru - Tubing	N&T	N&T Thru - Tubing	2022 Full Assessment with T&P Conversion			
Pending	N&T Thru - Tubing	N&T	N&T Thru - Tubing	N&T	2023 Full Assessment with T&P Conversion		
2013 – mid 2016	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	2023 Full Assessment with T&P Conversion		
2013 – mid 2016	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T	2024 Full Assessment with T&P Conversion	
2016 – 2018	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T	2025 Full Assessment with T&P Conversion	
2016 – 2018	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T	N&T Thru- Tubing	Full Assessment with T&P Conversion

Figure 4-2: Assessments performed in Year Following T&P Conversion

Re-Assessment Interval	Assessment in Year Following T&P Conversion														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
3-5 Years	N&T	N&T	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval												
5-8 Years	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval										
8-12 Years	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T Pressure Testing	N&T	N&T	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval							
12-15 Years	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T Pressure Testing	N&T	N&T	N&T Thru Tubing	N&T	N&T Pressure Testing	N&T	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval			

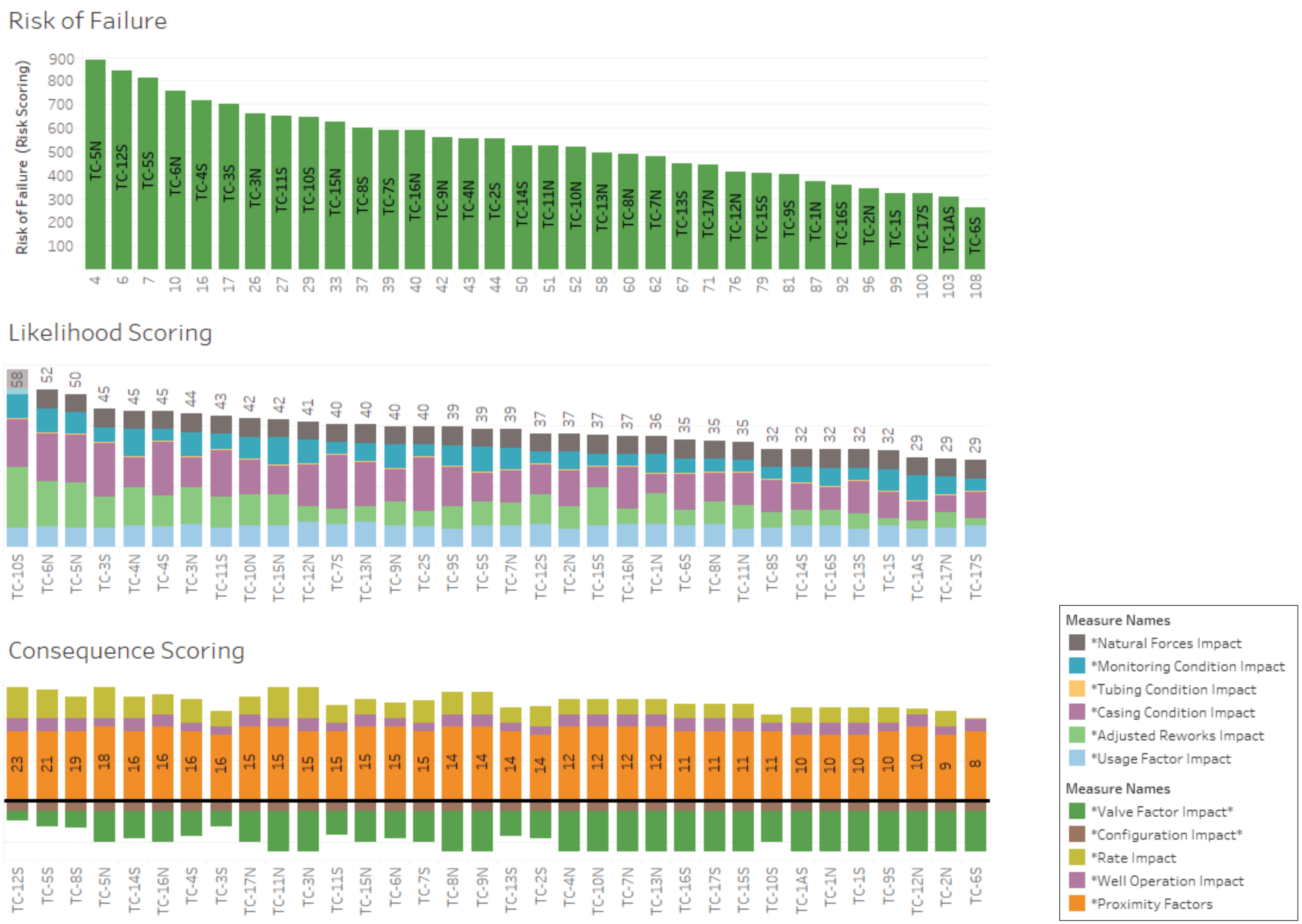
Appendix A – McDonald Island Relative Risk Well Evaluation

Figure A-1: Well by Well Risk of Failure Scoring – Whiskey Slough Station



**Note: The consequence scoring chart above shows a black line serving as the "zero" axis as the score components graphed below are mitigation components and reduce consequence.

Figure A-2: Well by Well Risk of Failure Scoring – Turner Cut Station



**Note: The consequence scoring chart above shows a black line serving as the "zero" axis as the score components graphed below are mitigation components and reduce consequence.

Figure A-3: Well by Well Risk of Failure Scoring – Peripheral Wells

**Note: The consequence scoring chart above shows a black line serving as the "zero" axis as the score components graphed below are mitigation components and reduce consequence.

Table 2 - Whiskey Slough – West Side Risk Evaluation (Input Data)

Well Name	API	Well Operation IW Wd only OBS	Well Operation IW = 3 Wd only = 2 OBS = 1	Spud Date	Completion Date	Years in Operation	Year of last Well Rework	Years since last Well Rework	# of Well Rework Performed	Measured Cement Bond Log TOC (feet)	Surface Csg (SC) Shoe, ft	Est. Distance to nearest offset well (feet)	Proximity to Roads (feet)	Proximity to Railroad (feet)	Proximity to Major Airport (feet)	Distance to Occupied Sturcture (HCA / Residence / Employee office-RE/Contrl Room building) (feet)	Proximity to Water (feet)
WS-7W	07720193	I/W	3	5/30/1973	6/14/1973	46	2011	8	4	860	632	25	560	5000	5000	364	4257
WS-9W	07720195	I/W	3	4/18/1973	5/6/1973	46	1994	25	2	1300	906	25	610	5000	5000	408	4303
WS-4W	07720214	WD	2	10/26/1973	11/12/1973	45	2008	11	2	1760	623	25	485	5000	5000	302	4185
WS-15W	07720233	WD	2	4/22/1974	5/4/1974	45	2011	8	3	3640	898	25	760	5000	5000	546	4447
WS-16W	07720231	WD	2	4/2/1974	4/20/1974	45	2005	14	4	3912	628	25	785	5000	5000	569	4472
WS-3W	07720213	WD	2	11/16/1973	12/1/1973	45	2012	7	3	3290	843	25	460	5000	5000	280	4161
WS-5W	07720211	WD	2	9/18/1973	10/22/1973	46	1999	20	2	935	896	25	510	5000	5000	322	4209
WS-2W	07720212	I/W	3	12/5/1973	12/19/1973	45	2009	10	3	3040	605	25	435	5000	5000	264	4138
WS-18W	07720465	I/W	3	6/27/1985	9/1/1985	34	2011	8	1	3200	620	25	835	5000	5000	620	4520
WS-1W	07720215	I/W	3	3/16/1974	3/31/1974	45	2015	4	5	3990	709	25	410	5000	5000	246	4114
WS-14W	07720238	OBS	1	5/6/1974	6/12/1975	45	1975	44	1	2750	916	25	685	5000	5000	477	4376
WS-11W	07720265	WD	2	7/21/1975	8/12/1975	44	1995	24	1	3210	883	25	660	5000	5000	453	4353
WS-12W	07720264	I/W	3	6/30/1975	7/20/1975	44	2018	1	4	2850	894	25	685	5000	5000	477	4376
WS-10W	07720534	I/W	3	4/3/1990	6/30/1990	29	1990	29	0	770	877	25	635	5000	5000	431	4329
WS-13W	07720241	WD	2	6/12/1975	9/2/1975	44	2018	1	5	2499	889	25	710	5000	5000	499	4399
WS-8W	07720194	I/W	3	5/8/1973	5/24/1973	46	2018	1	2	980	924	25	585	5000	5000	386	4281
WS-1AW	07720544	I/W	3	6/12/1991	7/1/1991	28	2018	1	1	1070	892	25	385	5000	5000	232	4090
WS-6W	07720192	WD	2	6/19/1973	7/8/1973	46	2018	1	2	780	860	25	535	5000	5000	342	4233
WS-19W	07720467	I/W	3	7/29/1985	9/19/1985	34	2018	1	3	2678	617	25	860	5000	5000	641	4543
WS-17W	07720166	I/W	3	9/7/1972	9/27/1972	47	2018	1	3	740	630	25	810	5000	5000	594	4495
WS-20W	07720535	I/W	3	4/19/1990	8/18/1990	29	2018	1	1	267	849	25	885	5000	5000	667	4569

Table 3 - Whiskey Slough – West Side Risk Evaluation (Likelihood Data)

Well Name	Well Operation IW = 3 (Likelihood) Wd only = 2 OBS = 1	Usage Factor	Adjusted # of Well Reworks	Original Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Inner String Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Source of Metal Loss on Production Casing Unknown = 4 Corrosion = 3 Mechanical = 2 None = 0	Potential Production Casing Mechanical Leak Path Uncovered Perforations = 5 Uncovered Stage collar = 4 Isolated (by cement or Inner String) Stage Collar = 3 Casing thread Leak = 2 None Identified/Not Applicable = 1	Dogleg Severity 0-5 %= 1 5-10% = 2 >10 % = 3	Inner String Installed Yes -2 No -1	Cement Bond Log TOC Full - 1 Inside SC - 2 Below SC - 3
WS-7W	3	38	4	4	0	4	4	1	2	1	3
WS-9W	3	44	2	4	0	4	4	1	2	1	3
WS-4W	2	32	2	4	0	4	4	3	2	1	3
WS-15W	2	31	3	4	0	4	4	3	2	1	3
WS-16W	2	33	4	4	0	4	4	3	1	1	3
WS-3W	2	31	3	4	0	4	4	3	1	1	3
WS-5W	2	35	2	4	0	4	4	3	1	1	3
WS-2W	3	38	3	4	0	4	4	1	1	1	3
WS-18W	3	34	1	4	0	4	4	1	2	1	3
WS-1W	3	36	2.5	1	1	1	0	3	2	2	3
WS-14W	1	36	1	4	0	4	4	1	1	1	3
WS-11W	2	36	1	4	0	4	4	3	2	1	3
WS-12W	3	35	2	3	1	1	0	3	3	2	3
WS-10W	3	39	0	4	0	4	4	1	1	1	2
WS-13W	2	28	2.5	2	0	2	2	3	2	1	3
WS-8W	3	36	1	1	0	1	0	1	3	1	3
WS-1AW	3	30	0.5	1	0	1	0	1	1	1	3
WS-6W	2	29	1	1	0	1	0	3	2	1	2
WS-19W	3	32	1.5	2	0	2	2	1	2	1	3
WS-17W	3	36	1.5	1	0	1	0	1	1	1	3
WS-20W	3	30	0.5	2	0	2	2	1	3	1	2

Table 4 - Whiskey Slough – West Side Risk Evaluation (Likelihood Data- Cont)

Well Name	**Tubing Wall Thickness** Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1 Not Applicable = 0	**Potential Tubing Mechanical Leak Path** Tubing thread Leak = 2 None Identified/Not Applicable = 0	**Packer Condition** Known Leak=2 Sealing/Not Applicable = 0	**Annular Condition Monitoring Plan In Place** Yes - 3 No - 1	**Sand Production** # of Grade 3 or more since last rework	**Gas Composition** None = 0 CO_2 = 1 H_2S = 5	**Wellhead Tbg Head Condition - Known Leak** Yes - 2 No- 1	**Wellhead flange Condition - Known Leak** Yes - 2 No - 1	**Wellhead hydraulic Port leak** Yes -2 No- 1	**Known Hydrate Formation** No = 0 Yes = 1
WS-7W	0	0	0	1	1	0	1	1	1	0
WS-9W	0	0	0	3	0	0	2	2	2	0
WS-4W	0	0	0	1	1	0	1	1	1	0
WS-15W	0	0	0	1	0	0	1	1	1	0
WS-16W	0	0	0	1	0	0	1	1	1	0
WS-3W	0	0	0	1	0	0	2	1	2	0
WS-5W	0	0	0	1	0	0	2	1	2	0
WS-2W	0	0	0	1	0	0	1	1	1	0
WS-18W	0	0	0	1	0	0	1	1	1	0
WS-1W	0	0	0	3	0	0	1	1	2	0
WS-14W	0	0	0	1	0	0	1	1	1	0
WS-11W	0	0	0	1	0	0	1	1	1	0
WS-12W	0	0	0	1	0	0	2	1	2	0
WS-10W	0	0	0	1	0	0	1	1	1	0
WS-13W	0	0	0	1	0	0	1	2	2	0
WS-8W	0	0	0	1	0	0	2	2	1	0
WS-1AW	0	0	0	1	0	0	2	2	2	0
WS-6W	0	0	0	1	0	0	1	1	1	0
WS-19W	0	0	0	1	0	0	2	2	2	0
WS-17W	0	0	0	1	0	0	1	1	1	0
WS-20W	0	0	0	1	0	0	1	1	1	0

Table 5 - Whiskey Slough – West Side Risk Evaluation (Likelihood Data- Cont)

Well Name	**Well Security** Gated/fenced = 1 No = 2	**Wellhead Surface Damage Protection** **Full** Barricade (k-rail/bollard) =1, **Partial** Barricade (k-rail/bollard) = 2 **None** (Fenced only) = 3	**Natural Force Flooding** No= 0 Yes = 1	**Natural Force Seismic** Low PGA = 1 Med PGA = 2 High PGA =3	**Natural Force Subsidence** No= 0 Yes = 1	**Natural Force Tsunami** No= 0 Yes= 1	**Natural Force Lanslide** No= 0 Yes = 1
WS-7W	1	2	1	1	1	0	0
WS-9W	1	2	1	1	1	0	0
WS-4W	1	2	1	1	1	0	0
WS-15W	1	2	1	1	1	0	0
WS-16W	1	2	1	1	1	0	0
WS-3W	1	2	1	1	1	0	0
WS-5W	1	2	1	1	1	0	0
WS-2W	1	2	1	1	1	0	0
WS-18W	1	2	1	1	1	0	0
WS-1W	1	2	1	1	1	0	0
WS-14W	1	2	1	1	1	0	0
WS-11W	1	2	1	1	1	0	0
WS-12W	1	2	1	1	1	0	0
WS-10W	1	2	1	1	1	0	0
WS-13W	1	2	1	1	1	0	0
WS-8W	1	2	1	1	1	0	0
WS-1AW	1	2	1	1	1	0	0
WS-6W	1	2	1	1	1	0	0
WS-19W	1	2	1	1	1	0	0
WS-17W	1	2	1	1	1	0	0
WS-20W	1	2	1	1	1	0	0

Table 6 - Whiskey Slough – West Side Risk Evaluation (Consequence Data)

Well Name	Max Rate MMcf/d	Well Operation IW = 3 (Consequence) Wd only = 2 OBS = 1	Wind Direction Impact High - 3 Low - 1	Occupied Sturcture >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Proximity to Offset wells Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Proximity to Roads Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 0-500 ft of Major Highway = 4	Proximity to Railroad Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Proximity to Major Airport >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Population Centers > 1 Mile =3 1-2 Mile =2 2-5 Mile =1 >5 Mile = 0	Proximity to Body of Water Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 Water Well = 4, Navigable Waterway = 5	Local Area Activities/Land Use Urban = 4 Residential = 3 Crop farming (Irrigation/fertilizer / Plane) = 2 Cattle farming = 1	Response to Well Incident Unmanned-2 Facility Manned-1
WS-7W	30	3	3	3	3	2	1	1	0	1	2	1
WS-9W	25	3	3	3	3	2	1	1	0	1	2	1
WS-4W	20	2	3	3	3	3	1	1	0	1	2	1
WS-15W	30	2	3	2	3	2	1	1	0	1	2	1
WS-16W	18	2	3	2	3	2	1	1	0	1	2	1
WS-3W	27	2	3	3	3	3	1	1	0	1	2	1
WS-5W	20	2	3	3	3	2	1	1	0	1	2	1
WS-2W	22	3	3	3	3	3	1	1	0	1	2	1
WS-18W	30	3	3	2	3	2	1	1	0	1	2	1
WS-1W	15	3	3	3	3	3	1	1	0	1	2	1
WS-14W	0	1	3	2	3	2	1	1	0	1	2	1
WS-11W	25	2	3	3	3	2	1	1	0	1	2	1
WS-12W	15	3	3	3	3	2	1	1	0	1	2	1
WS-10W	18	3	3	3	3	2	1	1	0	1	2	1
WS-13W	15	2	3	3	3	2	1	1	0	1	2	1
WS-8W	15	3	3	3	3	2	1	1	0	1	2	1
WS-1AW	15	3	3	3	3	3	1	1	0	1	2	1
WS-6W	15	2	3	3	3	2	1	1	0	1	2	1
WS-19W	0	3	3	2	3	2	1	1	0	1	2	1
WS-17W	0	3	3	2	3	2	1	1	0	1	2	1
WS-20W	0	3	3	2	3	2	1	1	0	1	2	1

Table 7 - Whiskey Slough – West Side Risk Evaluation (Consequence Data)

Well Name	Configuration T&C Flow -1 T&P - 4	DHSV Csg Deployment Yes -1 No- 0	DHSV Tbg Deployment Yes -1 No- 0	DHSV Tbg Condition # of Level 4 since installation	DHSV Csg Condition # of Level 4 since installation	DHSV Control Line Condition # of Level 4 since installation	Valve Factor	Likehood of Failure	Consequence of Failure	Risk of Failure (Risk Scoring)
WS-7W	1	1	1	3	1	0	0.75	54	21	1,139
WS-9W	1	1	1	0	0	1	1.00	49	19	913
WS-4W	1	1	1	5	1	0	0.67	44	19	852
WS-15W	1	1	1	3	0	0	1.25	48	17	807
WS-16W	1	1	1	4	0	0	1.20	53	14	736
WS-3W	1	1	1	0	0	0	2.00	49	14	701
WS-5W	1	1	1	4	0	0	1.20	45	16	698
WS-2W	1	1	1	0	0	0	2.00	47	14	649
WS-18W	1	1	1	1	0	0	1.50	37	17	607
WS-1W	1	1	1	0	0	0	2.00	44	12	536
WS-14W	1	0	0	0	0	0	-	36	15	526
WS-11W	1	1	1	0	0	0	2.00	39	13	500
WS-12W	1	1	1	0	0	0	2.00	41	11	461
WS-10W	1	1	1	1	0	0	1.50	31	15	448
WS-13W	1	1	1	0	0	0	2.00	43	10	442
WS-8W	1	1	1	0	0	0	2.00	33	11	373
WS-1AW	1	1	1	0	0	0	2.00	28	12	348
WS-6W	1	1	1	0	0	0	2.00	30	10	305
WS-19W	1	1	1	0	0	0	2.00	38	7	246
WS-17W	1	1	1	0	0	0	2.00	32	7	206
WS-20W	1	1	1	0	0	0	2.00	29	7	192

Table 8 – Whiskey Slough- East Side Risk Evaluation (Input Data)

Well Name	API	Well Operation IW Wd only OBS	Well Operation IW = 3 Wd only = 2 OBS = 1	Spud Date	Completion Date	Years in Operation	Year of last Well Rework	Years since last Well Rework	# of Well Rework Performed	Measured Cement Bond Log TOC (feet)	Surface Csg (SC) Shoe, ft	Est. Distance to nearest offset well (feet)	Proximity to Roads (feet)	Proximity to Railroad (feet)	Proximity to Major Airport (feet)	Distance to Occupied Sturcture (HCA / Residence / Employee office- RE/Contrl Room building) (feet)	Proximity to Water (feet)
WS-6E	07720185	I/W	3	2/7/1973	2/23/1973	46	2007	12	3	1372	908	25	255	5000	5000	416	4137
WS-9E	07720189	I/W	3	4/9/1973	4/21/1973	46	2007	12	3	950	886	25	330	5000	5000	475	4211
WS-5E	07720179	I/W	3	1/6/1973	1/24/1973	46	2012	7	3	620	908	25	230	5000	5000	398	4113
WS-12E	07720255	WD	2	1/14/1975	7/9/1975	44	2012	7	4	2523	587	25	405	5000	5000	538	4284
WS-7E	07720187	I/W	3	3/2/1973	3/17/1973	46	2012	7	3	0	891	25	280	5000	5000	437	4162
WS-4E	07720178	I/W	3	12/5/1972	1/3/1973	46	2007	12	3	740	1013	25	205	5000	5000	380	4088
WS-1AE	07720536	I/W	3	5/6/1990	6/15/1990	29	2009	10	1	1100	875	25	105	5000	5000	319	3989
WS-13E	07720256	WD	2	1/27/1975	4/2/1975	44	2005	14	2	3560	934	25	430	5000	5000	562	4309
WS-1E	07720168	WD	2	10/3/1972	10/22/1972	47	2005	14	3	1150	606	25	130	5000	5000	334	4016
WS-14E	07720257	WD	2	2/8/1975	2/25/1975	44	2005	14	3	3020	881	25	455	5000	5000	584	4334
WS-8E	07720188	WD	2	3/20/1973	4/3/1973	46	2012	7	4	1300	920	25	305	5000	5000	455	4187
WS-10E	07720190	OBS	1	4/26/1973	5/16/1973	46	1984	35	1	1170	913	25	355	5000	5000	496	4236
WS-11E	07720253	WD	2	12/7/1974	7/23/1975	44	2011	8	2	250	1231	25	380	5000	5000	517	4261
WS-3E	07720173	WD	2	11/21/1972	12/12/1972	46	2017	2	6	3991	598	25	180	5000	5000	365	4065
WS-2E	07720169	I/W	3	10/27/1972	11/17/1972	46	2017	2	4	3945	613	25	155	5000	5000	349	4041

Table 9 – Whiskey Slough- East Side Risk Evaluation (Likelihood Data)

Well Name	Well Operation IW = 3 (Likelihood) Wd only = 2 OBS = 1	Usage Factor	Adjusted # of Well Reworks	Original Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Inner String Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Source of Metal Loss on Production Casing Unknown = 4 Corrosion = 3 Mechanical = 2 None = 0	Potential Production Casing Mechanical Leak Path Uncovered Perforations = 5 Uncovered Stage collar = 4 Isolated (by cement or Inner String) Stage Collar = 3 Casing thread Leak = 2 None Identified/Not Applicable = 1	Dogleg Severity 0-5 %= 1 5-10% = 2 >10 % = 3	Inner String Installed Yes -2 No -1	Cement Bond Log TOC Full - 1 Inside SC - 2 Below SC - 3
WS-6E	3	39	3	4	0	4	4	1	1	1	3
WS-9E	3	39	3	4	0	4	4	1	2	1	3
WS-5E	3	38	3	4	0	4	4	1	2	1	2
WS-12E	2	30	4	4	0	4	4	3	2	1	3
WS-7E	3	38	3	4	0	4	4	1	2	1	1
WS-4E	3	39	3	4	0	4	4	1	2	1	2
WS-1AE	3	33	1	4	0	4	4	1	1	1	3
WS-13E	2	33	2	4	0	4	4	3	1	1	3
WS-1E	2	34	3	4	0	4	4	1	2	1	3
WS-14E	2	33	3	4	0	4	4	3	2	1	3
WS-8E	2	31	4	4	0	4	4	2	1	1	3
WS-10E	1	34	1	4	0	4	4	1	2	1	3
WS-11E	2	31	2	4	0	4	4	3	2	1	2
WS-3E	2	29	3	1	1	1	0	3	2	2	3
WS-2E	3	36	2	3	1	1	0	3	2	2	3

Table 10 – Whiskey Slough- East Side Risk Evaluation (Likelihood Data - Cont)

Well Name	**Tubing Wall Thickness** Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1 Not Applicable = 0	**Potential Tubing Mechanical Leak Path** Tubing thread Leak = 2 None Identified/Not Applicable = 0	**Packer Condition** Known Leak=2 Sealing/Not Applicable = 0	**Annular Condition Monitoring Plan In Place** Yes - 3 No - 1	**Sand Production** # of Grade 3 or more since last rework	**Gas Composition** None = 0 CO2 = 1 H2S = 5	**Wellhead Tbg Head Condition - Known Leak** Yes - 2 No- 1	**Wellhead flange Condition - Known Leak** Yes - 2 No - 1	**Wellhead hydraulic Port leak** Yes -2 No- 1	**Known Hydrate Formation** No = 0 Yes = 1
WS-6E	0	0	0	3	1	0	2	1	2	0
WS-9E	0	0	0	1	0	0	1	1	1	0
WS-5E	0	0	0	1	0	0	2	1	2	0
WS-12E	0	0	0	3	0	0	1	2	1	0
WS-7E	0	0	0	3	0	0	2	2	2	0
WS-4E	0	0	0	1	0	0	2	1	2	0
WS-1AE	0	0	0	1	0	0	2	1	2	0
WS-13E	0	0	0	1	0	0	1	1	1	0
WS-1E	0	0	0	3	0	0	2	2	1	0
WS-14E	0	0	0	1	0	0	1	2	1	0
WS-8E	0	0	0	3	0	0	1	1	1	0
WS-10E	0	0	0	1	0	0	1	1	1	0
WS-11E	0	0	0	1	0	0	1	1	1	0
WS-3E	0	0	0	1	0	0	2	1	2	0
WS-2E	0	0	0	1	0	0	2	2	2	0

Table 11 – Whiskey Slough- East Side Risk Evaluation (Likelihood Data)

Well Name	**Well Security** Gated/fenced = 1 No = 2	**Wellhead Surface Damage Protection** **Full** Barricade (k-rail/bollard) =1, **Partial** Barricade (k-rail/bollard) = 2 **None** (Fenced only) = 3	**Natural Force Flooding** No= 0 Yes = 1	**Natural Force Seismic** Low PGA = 1 Med PGA = 2 High PGA =3	**Natural Force Subsidence** No= 0 Yes = 1	**Natural Force Tsunami** No= 0 Yes= 1	**Natural Force Lanslide** No= 0 Yes = 1
WS-6E	1	2	1	1	1	0	0
WS-9E	1	2	1	1	1	0	0
WS-5E	1	2	1	1	1	0	0
WS-12E	1	2	1	1	1	0	0
WS-7E	1	2	1	1	1	0	0
WS-4E	1	2	1	1	1	0	0
WS-1AE	1	2	1	1	1	0	0
WS-13E	1	2	1	1	1	0	0
WS-1E	1	2	1	1	1	0	0
WS-14E	1	2	1	1	1	0	0
WS-8E	1	2	1	1	1	0	0
WS-10E	1	2	1	1	1	0	0
WS-11E	1	2	1	1	1	0	0
WS-3E	1	2	1	1	1	0	0
WS-2E	1	2	1	1	1	0	0

Table 12 – Whiskey Slough- East Side Risk Evaluation (Consequence Data)

Well Name	Max Rate MMcf/d	Well Operation IW = 3 (Consequence) Wd only = 2 OBS = 1	Wind Direction Impact High - 3 Low - 1	Occupied Sturcture >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Proximity to Offset wells Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Proximity to Roads Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 0-500 ft of Major Highway = 4	Proximity to Railroad Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Proximity to Major Airport >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Population Centers > 1 Mile =3 1-2 Mile =2 2-5 Mile =1 >5 Mile = 0	Proximity to Body of Water Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 Water Well = 4, Navigable Waterway = 5	Local Area Activities/Land Use Urban = 4 Residential = 3 Crop farming (Irrigation/fertilizer / Plane) = 2 Cattle farming = 1	Response to Well Incident Unmanned-2 Facility Manned-1
WS-6E	22	3	1	3	3	3	1	1	0	1	2	1
WS-9E	5	3	1	3	3	3	1	1	0	1	2	1
WS-5E	20	3	1	3	3	3	1	1	0	1	2	1
WS-12E	20	2	1	2	3	3	1	1	0	1	2	1
WS-7E	22	3	1	3	3	3	1	1	0	1	2	1
WS-4E	5	3	1	3	3	3	1	1	0	1	2	1
WS-1AE	20	3	1	3	3	3	1	1	0	1	2	1
WS-13E	18	2	1	2	3	3	1	1	0	1	2	1
WS-1E	15	2	1	3	3	3	1	1	0	1	2	1
WS-14E	5	2	1	2	3	3	1	1	0	1	2	1
WS-8E	22	2	1	3	3	3	1	1	0	1	2	1
WS-10E	0	1	1	3	3	3	1	1	0	1	2	1
WS-11E	30	2	1	2	3	3	1	1	0	1	2	1
WS-3E	10	2	1	3	3	3	1	1	0	1	2	1
WS-2E	5	3	1	3	3	3	1	1	0	1	2	1

Table 13 – Whiskey Slough- East Side Risk Evaluation (Consequence Data)

Well Name	Configuration T&C Flow -1 T&P - 4	DHSV Csg Deployment Yes -1 No- 0	DHSV Tbg Deployment Yes -1 No- 0	DHSV Tbg Condition # of Level 4 since installation	DHSV Csg Condition # of Level 4 since installation	DHSV Control Line Condition # of Level 4 since installation	Valve Factor	Likehood of Failure	Consequence of Failure	Risk of Failure (Risk Scoring)
WS-6E	1	1	1	4	4	0	0.40	**52**	**20**	**1,040**
WS-9E	1	1	1	5	4	0	0.37	**48**	**16**	**762**
WS-5E	1	1	1	4	0	0	1.20	**49**	**16**	**753**
WS-12E	1	1	1	3	0	0	1.25	**56**	**13**	**743**
WS-7E	1	1	1	1	0	0	1.50	**51**	**15**	**739**
WS-4E	1	1	1	3	1	0	0.75	**49**	**14**	**684**
WS-1AE	1	1	1	4	1	0	0.70	**38**	**18**	**681**
WS-13E	1	1	1	6	1	0	0.64	**43**	**16**	**672**
WS-1E	1	1	1	2	0	0	1.33	**51**	**13**	**638**
WS-14E	1	1	1	3	0	1	0.63	**50**	**13**	**625**
WS-8E	1	1	1	0	0	0	2.00	**53**	**11**	**591**
WS-10E	1	0	0	0	0	0	-	**37**	**15**	**533**
WS-11E	1	1	1	0	0	0	2.00	**42**	**12**	**506**
WS-3E	4	0	1	1	0	0	0.50	**44**	**8**	**351**
WS-2E	1	1	1	0	0	0	2.00	**41**	**8**	**320**

Table 14- Turner Cut Station – North Side Risk Evaluation (Input Data)

Well Name	API	Well Operation IW Wd only OBS	Well Operation IW = 3 Wd only = 2 OBS = 1	Spud Date	Completion Date	Years in Operation	Year of last Well Rework	Years since last Well Rework	# of Well Rework Performed	Measured Cement Bond Log TOC (feet)	Surface Csg (SC) Shoe, ft	Est. Distance to nearest offset well (feet)	Proximity to Roads (feet)	Proximity to Railroad (feet)	Proximity to Major Airport (feet)	Distance to Occupied Sturcture (HCA / Residence / Employee office-RE/Contrl Room building) (feet)	Proximity to Water (feet)
TC-5N	07720207	WD	2	8/1/1973	8/23/1973	46	2013	6	3	4637	614	25	465	5000	5000	450	1144
TC-6N	07720208	WD	2	8/29/1973	9/7/1973	46	2006	13	3	4550	898	25	440	5000	5000	425	1130
TC-3N	07720201	I/W	3	7/3/1973	7/17/1973	46	2016	3	5	4960	901	25	515	5000	5000	499	1174
TC-15N	07720239	I/W	3	7/12/1974	1/8/1975	45	2017	2	4	2790	904	25	215	5000	5000	228	1023
TC-16N	07720240	I/W	3	7/30/1974	12/19/1975	45	2010	9	1	2450	915	25	190	5000	5000	208	1015
TC-9N	07720227	I/W	3	2/7/1974	2/28/1974	45	2016	3	3	2915	897	25	365	5000	5000	356	1090
TC-4N	07720202	I/W	3	7/19/1973	8/3/1973	46	2016	3	5	1170	907	25	490	5000	5000	473	1158
TC-11N	07720229	WD	2	3/18/1974	4/1/1974	45	2013	6	3	870	897	25	315	5000	5000	311	1066
TC-10N	07720228	I/W	3	3/1/1974	3/16/1974	45	2017	2	4	4658	910	25	340	5000	5000	333	1079
TC-13N	07720234	I/W	3	4/18/1974	5/11/1974	45	2000	19	1	3330	794	25	265	5000	5000	267	1045
TC-8N	07720226	I/W	3	1/19/1974	2/5/1974	45	2014	5	3	3004	885	25	390	5000	5000	382	1103
TC-7N	07720225	I/W	3	12/12/1973	12/29/1973	45	2017	2	3	4674	605	25	415	5000	5000	404	1117
TC-17N	07720548	I/W	3	7/5/1991	7/25/1991	28	2014	5	2	570	863	25	165	5000	5000	190	1007
TC-12N	07720230	I/W	3	4/2/1974	4/17/1974	45	2000	19	1	2200	619	25	290	5000	5000	290	1055
TC-1N	07720196	I/W	3	5/23/1973	6/7/1973	46	2013	6	4	85	906	25	565	5000	5000	546	1203
TC-2N	07720199	WD	2	6/9/1973	6/29/1973	46	2018	1	3	210	882	25	540	5000	5000	522	1188

Table 15- Turner Cut Station – North Side Risk Evaluation (Likelihood Data)

Well Name	Well Operation IW = 3 (Likelihood) Wd only = 2 OBS = 1	Usage Factor	Adjusted # of Well Reworks	Original Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Inner String Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Source of Metal Loss on Production Casing Unknown = 4 Corrosion = 3 Mechanical = 2 None = 0	Potential Production Casing Mechanical Leak Path Uncovered Perforations = 5 Uncovered Stage collar = 4 Isolated (by cement or Inner String) Stage Collar = 3 Casing thread Leak = 2 None Identified/Not Applicable = 1	Dogleg Severity 0-5 %= 1 5-10% = 2 >10 % = 3	Inner String Installed Yes -2 No -1	Cement Bond Log TOC Full - 1 Inside SC - 2 Below SC - 3
TC-5N	2	31	3	4	0	4	4	3	1	1	3
TC-6N	2	33	3	4	0	4	4	3	1	1	3
TC-3N	3	36	2.5	3	1	1	0	3	1	2	3
TC-15N	3	36	2	2	0	2	2	1	1	1	3
TC-16N	3	38	1	4	0	4	4	1	1	1	3
TC-9N	3	36	1.5	3	1	1	0	3	2	2	3
TC-4N	3	36	2.5	2	1	1	0	3	1	2	3
TC-11N	2	30	1.5	2	0	2	2	2	2	1	2
TC-10N	3	36	2	1	1	1	0	3	3	2	3
TC-13N	3	41	1	4	0	4	4	1	2	1	3
TC-8N	3	37	1.5	2	0	2	2	1	1	1	3
TC-7N	3	36	1.5	1	1	1	0	3	2	2	3
TC-17N	3	31	1	1	0	1	0	1	1	1	2
TC-12N	3	41	1	4	0	4	4	1	1	1	3
TC-1N	3	37	2	1	0	1	0	2	1	1	2
TC-2N	2	29	1.5	2	0	2	2	3	2	1	2

Table 16- Turner Cut Station – North Side Risk Evaluation (Likelihood Data - Cont)

Well Name	**Tubing Wall Thickness** Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1 Not Applicable = 0	**Potential Tubing Mechanical Leak Path** Tubing thread Leak = 2 None Identified/Not Applicable = 0	**Packer Condition** Known Leak=2 Sealing/Not Applicable = 0	**Annular Condition Monitoring Plan In Place** Yes - 3 No - 1	**Sand Production** # of Grade 3 or more since last rework	**Gas Composition** None = 0 CO2 = 1 H2S = 5	**Wellhead Tbg Head Condition - Known Leak** Yes - 2 No- 1	**Wellhead flange Condition - Known Leak** Yes - 2 No - 1	**Wellhead hydraulic Port leak** Yes -2 No- 1	**Known Hydrate Formation** No = 0 Yes = 1
TC-5N	0	0	0	3	0	0	1	1	2	0
TC-6N	0	0	0	3	0	0	2	2	1	0
TC-3N	0	0	0	3	0	0	2	2	1	0
TC-15N	0	0	0	3	0	0	2	2	2	0
TC-16N	0	0	0	1	0	0	1	1	1	0
TC-9N	0	0	0	3	0	0	2	2	1	0
TC-4N	0	0	0	3	0	0	2	2	2	0
TC-11N	0	0	0	1	0	0	1	1	1	0
TC-10N	0	0	0	3	0	0	2	1	1	0
TC-13N	0	0	0	1	2	0	1	1	1	0
TC-8N	0	0	0	1	0	0	1	1	1	0
TC-7N	0	0	0	3	0	0	2	1	1	0
TC-17N	0	0	0	1	2	0	1	1	1	0
TC-12N	0	0	0	1	4	0	1	1	1	0
TC-1N	0	0	0	1	1	0	1	2	1	0
TC-2N	0	0	0	1	0	0	1	2	2	0

Table 17- Turner Cut Station – North Side Risk Evaluation (Likelihood Data - Cont)

Well Name	**Well Security** Gated/fenced = 1 No = 2	**Wellhead Surface Damage Protection** **Full** Barricade (k-rail/bollard) =1, **Partial** Barricade (k-rail/bollard) = 2 **None** (Fenced only) = 3	**Natural Force Flooding** No= 0 Yes = 1	**Natural Force Seismic** Low PGA = 1 Med PGA = 2 High PGA =3	**Natural Force Subsidence** No= 0 Yes = 1	**Natural Force Tsunami** No= 0 Yes= 1	**Natural Force Lanslide** No= 0 Yes = 1
TC-5N	1	2	1	1	1	0	0
TC-6N	1	2	1	1	1	0	0
TC-3N	1	2	1	1	1	0	0
TC-15N	1	2	1	1	1	0	0
TC-16N	1	2	1	1	1	0	0
TC-9N	1	2	1	1	1	0	0
TC-4N	1	2	1	1	1	0	0
TC-11N	1	2	1	1	1	0	0
TC-10N	1	2	1	1	1	0	0
TC-13N	1	2	1	1	1	0	0
TC-8N	1	2	1	1	1	0	0
TC-7N	1	2	1	1	1	0	0
TC-17N	1	2	1	1	1	0	0
TC-12N	1	2	1	1	1	0	0
TC-1N	1	2	1	1	1	0	0
TC-2N	1	2	1	1	1	0	0

Table 18- Turner Cut Station – North Side Risk Evaluation (Consequence Data)

Well Name	**Max Rate** MMcf/d	**Well Operation** IW = 3 (Consequence) Wd only = 2 OBS = 1	**Wind Direction Impact** High - 3 Low - 1	**Occupied Sturcture** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Offset wells Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Roads Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 0-500 ft of Major Highway = 4	**Proximity to Railroad Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Major Airport** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Population Centers** > 1 Mile =3 1-2 Mile =2 2-5 Mile =1 >5 Mile = 0	**Proximity to Body of Water Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 Water Well = 4, Navigable Waterway = 5	**Local Area Activities/Land Use** Urban = 4 Residential = 3 Crop farming (Irrigation/fertilizer / Plane) = 2 Cattle farming = 1	**Response to Well Incident** Unmanned-2 Facility Manned-1
TC-5N	31	2	3	3	3	3	1	1	0	1	2	1
TC-6N	15	2	3	3	3	3	1	1	0	1	2	1
TC-3N	30	3	3	3	3	2	1	1	0	1	2	1
TC-15N	15	3	3	3	3	3	1	1	0	1	2	1
TC-16N	20	3	3	3	3	3	1	1	0	1	2	1
TC-9N	22	3	3	3	3	3	1	1	0	1	2	1
TC-4N	15	3	3	3	3	3	1	1	0	1	2	1
TC-11N	31	2	3	3	3	3	1	1	0	1	2	1
TC-10N	15	3	3	3	3	3	1	1	0	1	2	1
TC-13N	15	3	3	3	3	3	1	1	0	1	2	1
TC-8N	22	3	3	3	3	3	1	1	0	1	2	1
TC-7N	15	3	3	3	3	3	1	1	0	1	2	1
TC-17N	17	3	3	3	3	3	1	1	0	1	2	1
TC-12N	6	3	3	3	3	3	1	1	0	1	2	1
TC-1N	15	3	3	2	3	2	1	1	0	1	2	1
TC-2N	15	2	3	2	3	2	1	1	0	1	2	1

Table 19- Turner Cut Station – North Side Risk Evaluation (Consequence Data)

Well Name	Configuration T&C Flow -1 T&P - 4	DHSV Csg Deployment Yes -1 No- 0	DHSV Tbg Deployment Yes -1 No- 0	DHSV Tbg Condition # of Level 4 since installation	DHSV Csg Condition # of Level 4 since installation	DHSV Control Line Condition # of Level 4 since installation	Valve Factor	Likehood of Failure	Consequence of Failure	Risk of Failure (Risk Scoring)
TC-5N	1	1	1	1	0	0	1.50	50	18	889
TC-6N	1	1	1	2	0	0	1.33	52	15	758
TC-3N	1	1	1	0	0	0	2.00	44	15	662
TC-15N	1	1	1	1	0	0	1.50	42	15	626
TC-16N	1	1	1	0	1	0	1.50	37	16	588
TC-9N	1	1	1	0	0	0	2.00	40	14	559
TC-4N	1	1	1	0	0	0	2.00	45	12	554
TC-11N	1	1	1	0	0	0	2.00	35	15	523
TC-10N	1	1	1	0	0	0	2.00	42	12	521
TC-13N	1	1	1	0	0	0	2.00	40	12	493
TC-8N	1	1	1	0	0	0	2.00	35	14	490
TC-7N	1	1	1	0	0	0	2.00	39	12	478
TC-17N	1	1	1	1	0	0	1.50	29	15	445
TC-12N	1	1	1	0	0	0	2.00	41	10	412
TC-1N	1	1	1	0	0	0	2.00	36	10	374
TC-2N	1	1	1	0	0	0	2.00	37	9	345

Table 20- Turner Cut Station South Side Wells Risk Evaluation (Input Data)

Well Name	API	Well Operation IW Wd only OBS	Well Operation IW = 3 Wd only = 2 OBS = 1	Spud Date	Completion Date	Years in Operation	Year of last Well Rework	Years since last Well Rework	# of Well Rework Performed	Measured Cement Bond Log TOC (feet)	Surface Csg (SC) Shoe, ft	Est. Distance to nearest offset well (feet)	Proximity to Roads (feet)	Proximity to Railroad (feet)	Proximity to Major Airport (feet)	Distance to Occupied Sturcture (HCA / Residence / Employee office-RE/Contrl Room building) (feet)	Proximity to Water (feet)
TC-12S	07720248	I/W	3	10/16/1974	5/16/1975	44	2014	5	4	1220	874	25	285	5000	5000	278	673
TC-5S	07720204	I/W	3	8/25/1973	9/8/1973	46	2016	3	3	4556	813	25	460	5000	5000	385	805
TC-4S	07720203	WD	2	9/21/1973	10/7/1973	46	2004	15	2	1400	916	25	485	5000	5000	402	824
TC-3S	07720216	WD	2	10/9/1973	10/27/1973	45	2010	9	2	5290	898	25	510	5000	5000	425	845
TC-11S	07720250	WD	2	10/29/1974	5/25/1975	44	2009	10	2	3022	926	25	310	5000	5000	291	692
TC-10S	07720251	WD	2	11/9/1974	3/6/1975	44	2010	9	4	0	599	25	335	5000	5000	303	710
TC-8S	07720533	I/W	3	3/15/1990	7/14/1990	29	2014	5	2	460	881	25	385	5000	5000	330	747
TC-7S	07720206	WD	2	7/10/1973	7/27/1973	46	1993	26	1	818	637	25	410	5000	5000	349	764
TC-2S	07720219	WD	2	10/31/1973	11/19/1973	45	2004	15	1	4470	888	25	535	5000	5000	444	864
TC-14S	07720244	I/W	3	9/9/1974	3/19/1975	45	2015	4	2	770	860	25	235	5000	5000	262	641
TC-13S	07720247	WD	2	9/20/1974	5/9/1975	45	2014	5	2	710	615	25	260	5000	5000	269	657
TC-15S	07720245	I/W	3	8/28/1974	6/15/1975	45	2015	4	5	920	919	25	210	5000	5000	258	625
TC-9S	07720252	WD	2	11/22/1974	2/16/1975	44	2014	5	3	830	710	25	360	5000	5000	315	728
TC-16S	07720243	I/W	3	8/10/1974	6/30/1975	45	2018	1	2	3020	880	25	185	5000	5000	253	607
TC-1S	07720218	I/W	3	11/21/1973	12/9/1973	45	2018	1	1	3140	770	25	560	5000	5000	464	886
TC-17S	07720258	I/W	3	4/3/1975	4/22/1975	44	2018	1	1	1270	904	25	160	5000	5000	254	594
TC-1AS	07720551	I/W	3	7/27/1991	8/15/1991	28	2017	2	1	1790	898	25	585	5000	5000	488	906
TC-6S	07720205	I/W	3	7/31/1973	8/22/1973	46	2018	1	2	5792	580	25	435	5000	5000	365	785

Table 21- Turner Cut Station South Side Wells Risk Evaluation (Likelihood Data)

Well Name	**Well Operation** IW = 3 (Likelihood) Wd only = 2 OBS = 1	**Usage Factor**	**Adjusted # of Well Reworks**	**Original Production Casing Wall Thickness** Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	**Inner String Production Casing Wall Thickness** Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	**Production Casing Wall Thickness** Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	**Source of Metal Loss on Production Casing** Unknown = 4 Corrosion = 3 Mechanical = 2 None = 0	**Potential Production Casing Mechanical Leak Path** Uncovered Perforations = 5 Uncovered Stage collar = 4 Isolated (by cement or Inner String) Stage Collar = 3 Casing thread Leak = 2 None Identified/Not Applicable = 1	**Dogleg Severity** 0-5 %= 1 5-10% = 2 >10 % = 3	**Inner String Installed** Yes -2 No -1	**Cement Bond Log TOC** Full - 1 Inside SC - 2 Below SC - 3
TC-12S	3	36	2	2	0	2	2	1	1	1	3
TC-5S	3	36	1.5	3	1	1	0	3	1	2	3
TC-4S	2	34	2	4	0	4	4	4	2	1	3
TC-3S	2	31	2	4	0	4	4	4	2	1	3
TC-11S	2	31	2	4	0	4	4	3	1	1	3
TC-10S	2	31	4	4	0	4	4	4	2	1	1
TC-8S	3	31	1	2	0	2	2	1	3	1	2
TC-7S	2	37	1	4	0	4	4	3	3	1	3
TC-2S	2	33	1	4	0	4	4	4	2	1	3
TC-14S	3	36	1	2	0	2	2	1	1	1	2
TC-13S	2	30	1	1	0	1	0	3	3	1	3
TC-15S	3	36	2.5	1	0	1	0	1	1	1	3
TC-9S	2	30	1.5	2	0	2	2	3	2	1	3
TC-16S	3	35	1	1	0	1	0	1	2	1	3
TC-1S	3	35	0.5	1	0	1	0	1	3	1	3
TC-17S	3	35	0.5	1	0	1	0	3	1	1	3
TC-1AS	3	30	0.5	1	0	1	0	1	1	1	3
TC-6S	3	36	1	1	1	1	0	3	3	2	3

Table 22- Turner Cut Station South Side Wells Risk Evaluation (Likelihood Data - Cont)

Well Name	Tubing Wall Thickness Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1 Not Applicable = 0	Potential Tubing Mechanical Leak Path Tubing thread Leak = 2 None Identified/Not Applicable = 0	Packer Condition Known Leak=2 Sealing/Not Applicable = 0	Annular Condition Monitoring Plan In Place Yes - 3 No - 1	Sand Production # of Grade 3 or more since last rework	Gas Composition None = 0 CO2 = 1 H2S = 5	Wellhead Tbg Head Condition - Known Leak Yes - 2 No- 1	Wellhead flange Condition - Known Leak Yes - 2 No - 1	Wellhead hydraulic Port leak Yes -2 No- 1	Known Hydrate Formation No = 0 Yes = 1
TC-12S	0	0	0	1	0	0	1	1	1	0
TC-5S	0	0	0	3	0	0	2	2	1	0
TC-4S	0	0	0	1	0	0	1	1	1	0
TC-3S	0	0	0	1	0	0	2	1	1	0
TC-11S	0	0	0	1	0	0	1	1	2	0
TC-10S	0	0	0	1	5	0	1	1	2	0
TC-8S	0	0	0	1	0	0	1	1	1	0
TC-7S	0	0	0	1	0	0	1	1	1	0
TC-2S	0	0	0	1	0	0	1	1	1	0
TC-14S	0	0	0	1	0	0	1	2	1	0
TC-13S	0	0	0	1	0	0	1	1	1	0
TC-15S	0	0	0	1	0	0	1	1	1	0
TC-9S	0	0	0	3	0	0	1	1	2	0
TC-16S	0	0	0	1	0	0	2	1	2	0
TC-1S	0	0	0	1	0	0	2	2	2	0
TC-17S	0	0	0	1	0	0	1	1	1	0
TC-1AS	0	0	0	1	1	0	2	2	2	0
TC-6S	0	0	0	1	0	0	1	1	2	0

Table 23- Turner Cut Station South Side Wells Risk Evaluation (Likelihood Data - Cont)

Well Name	**Well Security** Gated/fenced = 1 No = 2	**Wellhead Surface Damage Protection** **Full** Barricade (k-rail/bollard) =1, **Partial** Barricade (k-rail/bollard) = 2 **None** (Fenced only) = 3	**Natural Force Flooding** No= 0 Yes = 1	**Natural Force Seismic** Low PGA = 1 Med PGA = 2 High PGA =3	**Natural Force Subsidence** No= 0 Yes = 1	**Natural Force Tsunami** No= 0 Yes= 1	**Natural Force Lanslide** No= 0 Yes = 1
TC-12S	1	2	1	1	1	0	0
TC-5S	1	2	1	1	1	0	0
TC-4S	1	2	1	1	1	0	0
TC-3S	1	2	1	1	1	0	0
TC-11S	1	2	1	1	1	0	0
TC-10S	1	2	1	1	1	0	0
TC-8S	1	2	1	1	1	0	0
TC-7S	1	2	1	1	1	0	0
TC-2S	1	2	1	1	1	0	0
TC-14S	1	2	1	1	1	0	0
TC-13S	1	2	1	1	1	0	0
TC-15S	1	2	1	1	1	0	0
TC-9S	1	2	1	1	1	0	0
TC-16S	1	2	1	1	1	0	0
TC-1S	1	2	1	1	1	0	0
TC-17S	1	2	1	1	1	0	0
TC-1AS	1	2	1	1	1	0	0
TC-6S	1	2	1	1	1	0	0

Table 24- Turner Cut Station South Side Wells Risk Evaluation (Consequence Data)

Well Name	**Max Rate** MMcf/d	**Well Operation** IW = 3 (Consequence) Wd only = 2 OBS = 1	**Wind Direction Impact** High - 3 Low - 1	**Occupied Sturcture** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Offset wells Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Roads Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 0-500 ft of Major Highway = 4	**Proximity to Railroad Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Major Airport** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Population Centers** > 1 Mile =3 1-2 Mile =2 2-5 Mile =1 >5 Mile = 0	**Proximity to Body of Water Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 Water Well = 4, Navigable Waterway = 5	**Local Area Activities/Land Use** Urban = 4 Residential = 3 Crop farming (Irrigation/fertilizer / Plane) = 2 Cattle farming = 1	**Response to Well Incident** Unmanned-2 Facility Manned-1
TC-12S	30	3	1	3	3	3	1	1	0	2	2	1
TC-5S	29	3	1	3	3	3	1	1	0	2	2	1
TC-4S	23	2	1	3	3	3	1	1	0	2	2	1
TC-3S	15	2	1	3	3	2	1	1	0	2	2	1
TC-11S	17	2	1	3	3	3	1	1	0	2	2	1
TC-10S	8	2	1	3	3	3	1	1	0	2	2	1
TC-8S	21	3	1	3	3	3	1	1	0	2	2	1
TC-7S	22	2	1	3	3	3	1	1	0	2	2	1
TC-2S	20	2	1	3	3	2	1	1	0	2	2	1
TC-14S	22	3	1	3	3	3	1	1	0	2	2	1
TC-13S	15	2	1	3	3	3	1	1	0	2	2	1
TC-15S	15	3	1	3	3	3	1	1	0	2	2	1
TC-9S	15	2	1	3	3	3	1	1	0	2	2	1
TC-16S	15	3	1	3	3	3	1	1	0	2	2	1
TC-1S	15	3	1	3	3	2	1	1	0	2	2	1
TC-17S	15	3	1	3	3	3	1	1	0	2	2	1
TC-1AS	15	3	1	3	3	2	1	1	0	2	2	1
TC-6S	0	3	1	3	3	3	1	1	0	2	2	1

Table 25- Turner Cut Station South Side Wells Risk Evaluation (Consequence Data)

Well Name	Configuration T&C Flow -1 T&P - 4	DHSV Csg Deployment Yes -1 No- 0	DHSV Tbg Deployment Yes -1 No- 0	DHSV Tbg Condition # of Level 4 since installation	DHSV Csg Condition # of Level 4 since installation	DHSV Control Line Condition # of Level 4 since installation	Valve Factor	Likehood of Failure	Consequence of Failure	Risk of Failure (Risk Scoring)
TC-12S	1	1	1	5	2	0	0.50	**37**	**23**	**844**
TC-5S	1	1	1	0	1	1	0.75	**39**	**21**	**814**
TC-4S	1	1	1	3	0	0	1.25	**45**	**16**	**718**
TC-3S	1	1	1	1	0	1	0.75	**45**	**16**	**702**
TC-11S	1	1	1	5	0	0	1.17	**43**	**15**	**651**
TC-10S	1	1	1	0	1	0	1.50	**58**	**11**	**647**
TC-8S	1	1	1	1	2	0	0.83	**32**	**19**	**599**
TC-7S	1	1	1	1	0	0	1.50	**40**	**15**	**589**
TC-2S	1	1	1	2	0	0	1.33	**40**	**14**	**552**
TC-14S	1	1	1	2	0	0	1.33	**32**	**16**	**525**
TC-13S	1	1	1	3	0	0	1.25	**32**	**14**	**448**
TC-15S	1	1	1	0	0	0	2.00	**37**	**11**	**409**
TC-9S	1	1	1	0	0	0	2.00	**39**	**10**	**404**
TC-16S	1	1	1	0	0	0	2.00	**32**	**11**	**360**
TC-1S	1	1	1	0	0	0	2.00	**32**	**10**	**324**
TC-17S	1	1	1	0	0	0	2.00	**29**	**11**	**321**
TC-1AS	1	1	1	0	0	0	2.00	**29**	**10**	**306**
TC-6S	1	1	1	0	0	0	2.00	**35**	**8**	**263**

Table 26- McDonald Island Peripheral Wells Risk Evaluation (Input Data)

Well Name	API	Well Operation IW Wd only OBS	Well Operation IW = 3 Wd only = 2 OBS = 1	Spud Date	Completion Date	Years in Operation	Year of last Well Rework	Years since last Well Rework	# of Well Rework Performed	Measured Cement Bond Log TOC (feet)	Surface Csg (SC) Shoe, ft	Est. Distance to nearest offset well (feet)	Proximity to Roads (feet)	Proximity to Railroad (feet)	Proximity to Major Airport (feet)	Distance to Occupied Sturcture (HCA / Residence / Employee office-RE/Contrl Room building) (feet)	Proximity to Water (feet)
MCD-12	07700087	I/W	3	9/28/1960	10/12/1960	59	2008	11	1	111	882	366	100	5000	5000	598	226
MCD-11	07700086	I/W	3	9/13/1960	9/24/1960	59	2007	12	1	109	881	505	60	5000	5000	638	1461
MCD-5A	07720552	I/W	3	8/17/1991	9/4/1991	28	1991	28	0	1000	1000	367	970	5000	5000	870	1218
ZUCK-3	07700093	I/W	3	10/28/1949	11/14/1949	69	1967	52	1	2840	490	1416	245	5000	5000	2215	5637
MCD-10	07700085	I/W	3	8/27/1960	9/9/1960	59	1986	33	1	117	878	1412	60	5000	5000	1324	4219
MCD-15	07720444	I/W	3	10/10/1984	12/5/1984	34	1984	35	0	800	883	122	1,225	5000	5000	737	2629
TILD-1	07700090	OBS	1	1/14/1937	2/24/1937	82	1985	34	1	3549	500	170	1,220	5000	5000	1516	2511
MCD-4	07700080	OBS	1	10/23/1949	11/17/1949	69	1971	48	1	2920	510	1232	990	5000	5000	1607	2381
MCD-13	07700088	I/W	3	10/16/1960	10/26/1960	58	1982	37	1	0	887	1308	645	5000	5000	1206	3662
LMAC-1	07720609	I/W	3	7/18/1999	8/23/1999	20	1999	20	0	950	835	1046	1,940	5000	5000	1791	2165
MCD-14	07720441	I/W	3	8/23/1984	10/6/1984	35	1984	35	0	850	897	1756	1,110	5000	5000	777	2684
MCD-6	07700082	OBS	1	10/18/1949	11/8/1949	69	1985	34	1	3520	501	1540	1,060	5000	5000	1931	3812
ZUCK-1	07700091	OBS	1	7/9/1936	8/6/1936	83	1967	52	1	2880	508	1920	1,240	5000	5000	2516	4961
MCD-7	07700083	OBS	1	11/10/1949	11/29/1949	69	1965	54	1	3520	492	1427	1,030	5000	5000	1915	5544
ROB-2	07720523	OBS	1	10/31/1989	5/16/1990	29	1990	29	0	910	844	127	1,475	5000	5000	1770	2687
ROB-1	07720524	OBS	1	10/12/1989	5/5/1990	29	1990	29	0	850	875	226	1,350	5000	5000	1647	2601
ZUCK-H	07720010	OBS	1	6/16/1967	8/4/1967	52	1967	52	0	3650	980	3310	4,475	5000	5000	2104	5389
MCD-9	07700084	OBS	1	8/11/1960	8/24/1960	59	2016	3	1	0	874	1560	405	5000	5000	968	2945

Table 27- McDonald Island Peripheral Wells Risk Evaluation (Likelihood Data)

Well Name	Well Operation IW = 3 (Likelihood) Wd only = 2 OBS = 1	Usage Factor	Adjusted # of Well Reworks	Original Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Inner String Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Source of Metal Loss on Production Casing Unknown = 4 Corrosion = 3 Mechanical = 2 None = 0	Potential Production Casing Mechanical Leak Path Uncovered Perforations = 5 Uncovered Stage collar = 4 Isolated (by cement or Inner String) Stage Collar = 3 Casing thread Leak = 2 None Identified/Not Applicable = 1	Dogleg Severity 0-5 %= 1 5-10% = 2 >10 % = 3	Inner String Installed Yes -2 No -1	Cement Bond Log TOC Full - 1 Inside SC - 2 Below SC - 3
MCD-12	3	43	1	4	0	4	4	1	1	1	2
MCD-11	3	44	1	4	0	4	4	1	1	1	2
MCD-5A	3	39	0	4	0	4	4	1	1	1	2
ZUCK-3	3	60	1	4	0	4	4	1	1	1	3
MCD-10	3	51	1	4	0	4	4	1	1	1	2
MCD-15	3	43	0	4	0	4	4	1	2	1	2
TILD-1	1	45	1	4	0	4	4	1	1	1	3
MCD-4	1	46	1	4	0	4	4	4	1	1	3
MCD-13	3	52	1	4	0	4	4	1	1	1	1
LMAC-1	3	33	0	4	0	4	4	1	1	1	3
MCD-14	3	43	0	4	0	4	4	1	2	1	2
MCD-6	1	41	1	4	0	4	4	1	1	1	3
ZUCK-1	1	52	1	4	1	4	4	3	1	1	3
MCD-7	1	48	1	4	0	4	4	1	1	1	3
ROB-2	1	26	0	4	0	4	4	1	1	1	3
ROB-1	1	26	0	4	0	4	4	1	1	1	2
ZUCK-H	1	41	0	4	0	4	4	1	2	1	3
MCD-9	1	27	0.5	1	0	1	0	1	1	1	1

Table 28- McDonald Island Peripheral Wells Risk Evaluation (Likelihood Data - Cont)

Well Name	**Tubing Wall Thickness** Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1 Not Applicable = 0	**Potential Tubing Mechanical Leak Path** Tubing thread Leak = 2 None Identified/Not Applicable = 0	**Packer Condition** Known Leak=2 Sealing/Not Applicable = 0	**Annular Condition Monitoring Plan In Place** Yes - 3 No - 1	**Sand Production** # of Grade 3 or more since last rework	**Gas Composition** None = 0 CO_2 = 1 H_2S = 5	**Wellhead Tbg Head Condition - Known Leak** Yes - 2 No- 1	**Wellhead flange Condition - Known Leak** Yes - 2 No - 1	**Wellhead hydraulic Port leak** Yes -2 No- 1	**Known Hydrate Formation** No = 0 Yes = 1
MCD-12	0	0	0	1	1	0	2	1	1	0
MCD-11	0	0	0	1	1	0	1	1	1	0
MCD-5A	0	0	0	1	0	0	1	1	1	0
ZUCK-3	0	0	0	1	0	0	1	1	1	0
MCD-10	0	0	0	1	0	0	1	1	1	0
MCD-15	0	0	0	1	0	0	1	1	1	0
TILD-1	0	0	0	1	0	0	1	1	1	0
MCD-4	0	0	0	1	0	0	2	1	1	0
MCD-13	0	0	0	1	0	0	2	1	1	0
LMAC-1	0	0	0	1	0	0	1	1	1	0
MCD-14	0	0	0	1	0	0	1	1	1	0
MCD-6	0	0	0	1	0	0	1	1	1	0
ZUCK-1	0	0	0	1	0	0	1	1	1	0
MCD-7	0	0	0	1	0	0	1	1	1	0
ROB-2	0	0	0	1	0	0	1	2	1	0
ROB-1	0	0	0	1	0	0	1	1	1	0
ZUCK-H	0	0	0	1	0	0	1	1	1	0
MCD-9	0	0	0	1	0	0	1	1	1	0

Table 29- McDonald Island Peripheral Wells Risk Evaluation (Likelihood Data - Cont)

Well Name	**Well Security** Gated/fenced = 1 No = 2	**Wellhead Surface Damage Protection** **Full** Barricade (k-rail/bollard) =1, **Partial** Barricade (k-rail/bollard) = 2 **None** (Fenced only) = 3	**Natural Force Flooding** No= 0 Yes = 1	**Natural Force Seismic** Low PGA = 1 Med PGA = 2 High PGA =3	**Natural Force Subsidence** No= 0 Yes = 1	**Natural Force Tsunami** No= 0 Yes= 1	**Natural Force Lanslide** No= 0 Yes = 1
MCD-12	1	3	1	1	1	0	0
MCD-11	1	3	1	1	1	0	0
MCD-5A	1	3	1	1	1	0	0
ZUCK-3	1	3	1	1	1	0	0
MCD-10	1	3	1	1	1	0	0
MCD-15	1	3	1	1	1	0	0
TILD-1	1	3	1	1	1	0	0
MCD-4	1	3	1	1	1	0	0
MCD-13	1	3	1	1	1	0	0
LMAC-1	1	3	1	1	1	0	0
MCD-14	1	3	1	1	1	0	0
MCD-6	1	3	1	1	1	0	0
ZUCK-1	1	3	1	1	1	0	0
MCD-7	1	3	1	1	1	0	0
ROB-2	1	3	1	1	1	0	0
ROB-1	1	3	1	1	1	0	0
ZUCK-H	1	3	1	1	1	0	0
MCD-9	1	3	1	1	1	0	0

Table 30- McDonald Island Peripheral Wells Risk Evaluation (Consequence Data)

Well Name	**Max Rate** MMcf/d	**Well Operation** IW = 3 (Consequence) Wd only = 2 OBS = 1	**Wind Direction Impact** High - 3 Low - 1	**Occupied Sturcture** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Offset wells Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Roads Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 0-500 ft of Major Highway = 4	**Proximity to Railroad Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Major Airport** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Population Centers** > 1 Mile =3 1-2 Mile =2 2-5 Mile =1 >5 Mile = 0	**Proximity to Body of Water Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 Water Well = 4, Navigable Waterway = 5	**Local Area Activities/Land Use** Urban = 4 Residential = 3 Crop farming (Irrigation/fertilizer / Plane) = 2 Cattle farming = 1	**Response to Well Incident** Unmanned-2 Facility Manned-1
MCD-12	8	3	1	2	3	3	1	1	0	3	2	1
MCD-11	17	3	1	2	2	3	1	1	0	1	2	1
MCD-5A	21	3	1	2	3	2	1	1	0	2	2	1
ZUCK-3	16	3	1	1	1	3	1	1	0	1	2	1
MCD-10	17	3	1	1	1	3	1	1	0	1	2	1
MCD-15	17	3	1	2	3	1	1	1	0	1	2	1
TILD-1	0	1	1	1	3	1	1	1	0	1	2	1
MCD-4	0	1	1	1	1	2	1	1	0	1	2	1
MCD-13	16	3	1	1	1	2	1	1	0	1	2	1
LMAC-1	20	3	1	1	1	2	1	1	0	2	2	1
MCD-14	11	3	1	2	3	1	1	1	0	1	2	1
MCD-6	0	1	1	1	1	2	1	1	0	1	2	1
ZUCK-1	0	1	1	1	1	1	1	1	0	1	2	1
MCD-7	0	1	1	1	1	1	1	1	0	1	2	1
ROB-2	0	1	1	1	3	1	1	1	0	1	2	1
ROB-1	0	1	1	1	3	1	1	1	0	1	2	1
ZUCK-H	0	1	1	1	1	1	1	1	0	1	2	1
MCD-9	0	1	1	1	1	3	1	1	0	1	2	1

Table 31- McDonald Island Peripheral Wells Risk Evaluation (Consequence Data)

Well Name	Configuration T&C Flow -1 T&P - 4	DHSV Csg Deployment Yes -1 No- 0	DHSV Tbg Deployment Yes -1 No- 0	DHSV Tbg Condition # of Level 4 since installation	DHSV Csg Condition # of Level 4 since installation	DHSV Control Line Condition # of Level 4 since installation	Valve Factor	Likehood of Failure	Consequence of Failure	Risk of Failure (Risk Scoring)
MCD-12	1	0	0	0	0	0	-	40	20	777
MCD-11	1	0	0	0	0	0	-	39	19	721
MCD-5A	1	0	0	0	0	0	-	32	21	656
ZUCK-3	1	0	0	0	0	0	-	42	17	697
MCD-10	1	0	0	0	0	0	-	39	17	660
MCD-15	1	0	0	0	0	0	-	34	18	596
TILD-1	1	0	0	0	0	0	-	39	11	410
MCD-4	1	0	0	0	0	0	-	43	10	410
MCD-13	1	0	0	0	0	0	-	39	15	606
LMAC-1	1	0	0	0	0	0	-	32	18	554
MCD-14	1	0	0	0	0	0	-	34	16	549
MCD-6	1	0	0	0	0	0	-	38	10	363
ZUCK-1	1	0	0	0	0	0	-	42	9	360
MCD-7	1	0	0	0	0	0	-	40	9	336
ROB-2	1	0	0	0	0	0	-	31	11	328
ROB-1	1	0	0	0	0	0	-	29	11	307
ZUCK-H	1	0	0	0	0	0	-	34	9	291
MCD-9	1	0	0	0	0	0	-	24	11	251

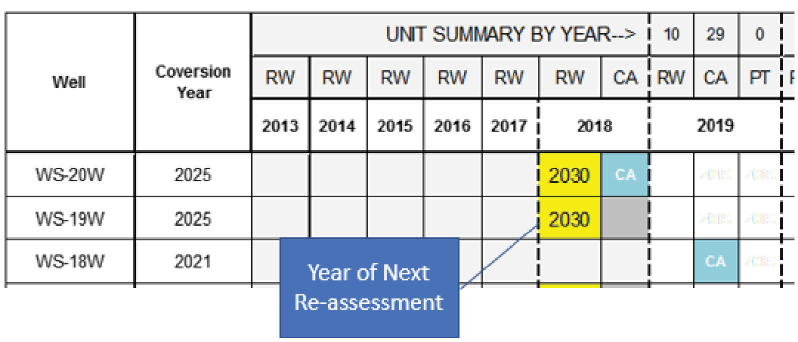
Appendix B - McDonald Island Well Construction Standard Implementation Plan and Assessment Schedule

The following figures provide an overview of the applied methodology from Section 4 that includes conversion of PG&E's wells to tubing and packer and brings them into conformance with §1726.5 of the final regulations put forth by the Division. Additionally, the figures demonstrate the assessment methodology – both pre- and post-conversion to tubing and packer configuration. The plan shown below for each well is based on addressing wells with the highest risk identified in the risk analysis shown in Appendix A. The planned schedules in the following figures are based on current data in the risk model. As new monitoring data is received, the plan below is subject to change.

The charts below show three possible activities for each well by year from 2019 thru 2025:

1. Thru-tubing casing assessment (blue)
2. T&P conversion/full assessment (green)
3. 5-year re-assessment pressure test (purple)

Additionally, for wells previously assessed, the schedule is shaded with yellow and the planned reassessment year based on casing condition observed is noted.



Well	Coversion Year	UNIT SUMMARY BY YEAR-->							10	29	0
		RW	RW	RW	RW	RW	RW	CA	RW	CA	PT
		2013	2014	2015	2016	2017	2018		2019		
WS-20W	2025						2030	CA			
WS-19W	2025						2030				
WS-18W	2021									CA	

For wells previously assessed, the decision to run a third thru-tubing log will rest with PG&E Reservoir Engineering following review of 2 sequential cycles thru-tubing logging results; note Example 1 shown below. If the analysis indicates a change in condition that requires

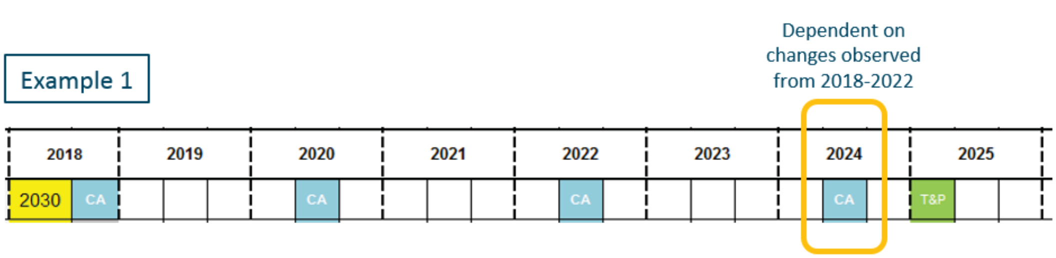


Figure B.1: Well Implementation and Assessment Schedule – Whiskey Slough West

Well	Coversion Year	2013	2014	2015	2016	2017	2018	2018	2019	2019	2019	2020	2020	2020	2021	2021	2021	2022	2022	2022	2023	2023	2023	2024	2024	2024	2025	2025	2025
		RW	RW	RW	RW	RW	RW	CA	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT
UNIT SUMMARY BY YEAR-->									10	29	0	14	33	0	14	27	0	13	45	0	13	22	0	13	35	10	10	26	12
WS-20W	2025						2030	CA					CA						CA						CA		T&P		
WS-19W	2025						2030						CA						CA						CA		T&P		
WS-18W	2021									CA					T&P							CA						CA	
WS-17W	2025						2030						CA						CA						CA		T&P		
WS-16W	2020											T&P							CA						CA				PT
WS-15W	2020											T&P							CA						CA				PT
WS-14W	2022									CA						CA		T&P							CA				
WS-13W	2024						2030						CA						CA					T&P					
WS-12W	2024						2030						CA						CA					T&P					
WS-11W	2022									CA						CA		T&P							CA				
WS-10W	2022									CA						CA		T&P							CA				
WS-9W	2020											T&P							CA						CA				PT
WS-8W	2024						2030						CA						CA					T&P					
WS-7W	2019								T&P							CA						CA				PT			
WS-6W	2025						2030						CA						CA						CA		T&P		
WS-5W	2021									CA					T&P							CA						CA	
WS-4W	2020											T&P							CA						CA				PT
WS-3W	2021									CA					T&P							CA						CA	
WS-2W	2021									CA					T&P							CA						CA	
WS-1W	2023			2027									CA						CA		T&P							CA	
WS-1AW	2024						2030						CA						CA					T&P					

Legend

RW Casing Assessment	Year of Relog
Thru-Tubing Casing Assessment	CA
Tubing & Packer Conversion Rework	T&P
Pressure Test (T&P)	PT
Reinspection Rework	RW
Plug & Abandon	P&A

Figure B.2: Well Implementation and Assessment Schedule – Whiskey Slough East

Well	Coversion Year	UNIT SUMMARY BY YEAR-->							10	29	0	14	33	0	14	27	0	13	45	0	13	22	0	13	35	10	10	26	12
		RW	RW	RW	RW	RW	RW	CA	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT
		2013	2014	2015	2016	2017	2018		2019			2020			2021			2022			2023			2024			2025		
WS-14E	2019								T&P							CA						CA				PT			
WS-13E	2021									CA					T&P							CA						CA	
WS-12E	2020											T&P							CA						CA				PT
WS-11E	2019								T&P							CA						CA				PT			
WS-10E	2022									CA						CA		T&P							CA				
WS-9E	2020											T&P							CA						CA				PT
WS-8E	2019								T&P							CA						CA				PT			
WS-7E	2020											T&P							CA						CA				PT
WS-6E	2019								T&P							CA						CA				PT			
WS-5E	2020											T&P							CA						CA				PT
WS-4E	2021									CA					T&P							CA						CA	
WS-3E	2029			na	2029	T&P		CA		CA						CA												CA	
WS-2E	2025					2029							CA						CA						CA		T&P		
WS-1E	2020											T&P							CA						CA				PT
WS-1AE	2021									CA					T&P							CA						CA	

Legend

- RW Casing Assessment — Year of Relog
- Thru-Tubing Casing Assessment — CA
- Tubing & Packer Conversion Rework — T&P
- Pressure Test (T&P) — PT
- Reinspection Rework — RW
- Plug & Abandon — P&A

Figure B.3: Well Implementation and Assessment Schedule – Turner Cut North

Well	Coversion Year	UNIT SUMMARY BY YEAR-->							10	29	0	14	33	0	14	27	0	13	45	0	13	22	0	13	35	10	10	26	12
		RW	RW	RW	RW	RW	RW	CA	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT
		2013	2014	2015	2016	2017	2018		2019			2020			2021			2022			2023			2024			2025		
TC-1N	2023	2021											CA						CA		T&P							CA	
TC-2N	2024	2021					2030						CA						CA					T&P					
TC-3N	2024				2028								CA						CA					T&P					
TC-4N	2024				2028			CA					CA						CA					T&P					
TC-5N	2020											T&P							CA						CA				PT
TC-6N	2020											T&P							CA						CA				PT
TC-7N	2024				2028	2029							CA						CA					T&P					
TC-8N	2023		2026										CA						CA		T&P							CA	
TC-9N	2024				2028			CA					CA						CA					T&P					
TC-10N	2024	2025			2028	2029							CA						CA					T&P					
TC-11N	2023	2025											CA						CA		T&P							CA	
TC-12N	2020											T&P							CA						CA				PT
TC-13N	2022									CA						CA		T&P							CA				
TC-15N	2024					2025							CA						CA					T&P					
TC-16N	2022									CA						CA		T&P							CA				
TC-17N	2023		2026										CA						CA		T&P							CA	

Legend

RW Casing Assessment	Year of Relog
Thru-Tubing Casing Assessment	CA
Tubing & Packer Conversion Rework	T&P
Pressure Test (T&P)	PT
Reinspection Rework	RW
Plug & Abandon	P&A

Figure B.4: Well Implementation and Assessment Schedule – Turner Cut South

Well	Coversion Year	UNIT SUMMARY BY YEAR-->							10	29	0	14	33	0	14	27	0	13	45	0	13	22	0	13	35	10	10	26	12
		RW	RW	RW	RW	RW	RW	CA	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT
		2013	2014	2015	2016	2017	2018		2019			2020			2021			2022			2023			2024			2025		
TC-1AS	2025				2028								CA						CA						CA		T&P		
TC-1S	2025						2030						CA						CA						CA		T&P		
TC-2S	2019								T&P							CA						CA				PT			
TC-3S	2021									CA					T&P							CA						CA	
TC-4S	2021									CA					T&P							CA						CA	
TC-5S	2024				2024								CA						CA					T&P					
TC-6S	2025						2030						CA						CA						CA		T&P		
TC-7S	2019								T&P							CA						CA				PT			
TC-8S	2023		2026										CA						CA		T&P							CA	
TC-9S	2023		2026										CA						CA		T&P							CA	
TC-10S	2021									CA					T&P							CA						CA	
TC-11S	2021									CA					T&P							CA						CA	
TC-12S	2019		2026						T&P							CA						CA				PT			
TC-13S	2023		2026										CA						CA		T&P							CA	
TC-14S	2023			2027									CA						CA		T&P							CA	
TC-15S	2023			2027									CA						CA		T&P							CA	
TC-16S	2024						2030						CA						CA					T&P					
TC-17S	2025						2030						CA						CA						CA		T&P		

Legend

RW Casing Assessment	Year of Relog
Thru-Tubing Casing Assessment	CA
Tubing & Packer Conversion Rework	T&P
Pressure Test (T&P)	PT
Reinspection Rework	RW
Plug & Abandon	P&A

Figure B.5: Well Implementation and Assessment Schedule – Peripheral

Well	Coversion Year	UNIT SUMMARY BY YEAR-->							10	29	0	14	33	0	14	27	0	13	45	0	13	22	0	13	35	10	10	26	12
		RW	RW	RW	RW	RW	RW	CA	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT
		2013	2014	2015	2016	2017	2018		2019			2020			2021			2022			2023			2024			2025		
LMac-1	2022									CA						CA		T&P							CA				
MCD-10	2022									CA						CA		T&P							CA				
MCD-11	2022									CA						CA		T&P							CA				
MCD-12	2021									CA					T&P							CA						CA	
MCD-13	2022									CA						CA		T&P							CA				
MCD-14	2023									CA						CA					T&P							CA	
MCD-15	2022									CA						CA		T&P							CA				
MCD-4	2022									CA						CA		T&P							CA				
MCD-5A	2022									CA						CA		T&P							CA				
MCD-6	2021														P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A
MCD-7	2021														P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A
MCD-9	2025				2028			CA					CA						CA						CA		T&P		
ROB-1	2023									CA						CA					T&P							CA	
ROB-2	2020											P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A
TILD-1	2020											P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A
ZUCK-1	2019								T&P							CA						CA				PT			
ZUCK-3	2019								T&P							CA						CA				PT			
ZUCK-H	2023									CA						CA					T&P							CA	

Legend

- RW Casing Assessment: Year of Relog
- Thru-Tubing Casing Assessment: CA
- Tubing & Packer Conversion Rework: T&P
- Pressure Test (T&P): PT
- Reinspection Rework: RW
- Plug & Abandon: P&A

Los Medanos Underground Storage Field: Well Risk Evaluation and Construction Standard Implementation Plan

Gas Storage Asset Management Department

Publication Date: March 29, 2019

Table of Contents

1. Introduction

This plan provides the applied individual well risk assessment as detailed in PG&E's Underground Storage Risk and Integrity Management Plan and is specific to the Pleasant Creek Storage Field Facility wells. This plan is a companion document to the Underground Storage Risk and Integrity Management Plan and is intended to be used in conjunction with the preventative and mitigation (P&M) measures included in the noted plan.

Under the Interim Final Rule (effective January 2017) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and API RP 1171 incorporated by reference, operators shall develop a program to manage risk that includes a process to assess risk related to the storage operation on a consistent basis. Additionally, under the Final Regulations (effective October 2018) issued by Division of Oil, Gas, and Geothermal Resources (DOGGR) require operators to perform a risk assessment on a well-by-well basis (§1726.3(c)(2)(4)).

Contained within this implementation plan is the planned schedule to convert PG&E's storage wells at Pleasant Creek to conform with the construction requirements of dual barriers required in Final Regulations (effective October 2018) issued by Division of Oil, Gas, and Geothermal Resources (DOGGR).

Lastly, this plan provides the performance based reassessment methodology and plan for wells following baseline and subsequent inspections.

2. Relative Risk Well Model Approach and Data Sources

Individual well-by-well risk ranking allows PG&E to manage P&M programs to adequately address highest risk assets and prioritize capital projects accordingly. The relative risk ranking model database manages and tracks the inputs, both static and dynamic, to evaluate the relative risk of each well.

Continuous Evaluation (CE) is used to evaluate the integrity of each well based on data integration from both integrity assessments performed and routine maintenance, operations, and testing performed to evaluate asset condition and subsequent risk profile. Data collected from the P&M measures are used to inform the scoring assignments. Additionally, baseline casing assessment and reinspection data are input into the model. Reinspection frequency is based on the Underground Storage Risk and Integrity Management Plan, Appendix C – Casing Inspection Survey Frequency Tree.

2.1. Roles and Responsibilities

Reservoir Engineering is responsible for analyzing all the available asset data collected in the practices outlined in the Underground Storage Risk & Integrity Management Plan to evaluate the overall condition and exposure of each well asset.

2.2. Publication Schedule of the Relative Risk Model

The model is maintained throughout the year as new data becomes available and the following schedule guides the formal publication/snapshot of the relative risk model.

Publication	Purpose
By July 31	Identifies/confirms well population scheduled for next two-year rework cycles
By January 31	Integrates previous season rework Integrates year end data to identify any emergent or break in work to be addressed in the coming year and confirms five-year outlook

2.3. Relative Risk Model Attributes Inputs

The following sections below outline the various attributes and inputs that are considered in the relative risk ranking analysis. The data includes both static and dynamic data; static data is unchanging and does not require annual review, whereas dynamic data is dependent on testing result inputs.

The risk score for each well is computed by summing the score components that impact likelihood of loss of containment and multiplying that value by the sum of the consequence score impacts to safety, environment, and reliability.

Likelihood Score Components	Consequence Score Components
• Usage Factor • Adjusted Rework Factor • Production Casing Condition Factor • Tubing and Packer Condition Factor • Monitoring and Inspection Condition Factor • Wellhead Security Factor • Natural Force Factor	• Well Rate Factor • Well Operation Factor • Wind Direction Impact • Proximity Factors: Occupied Structure, Offset Well, Road and Railway Proximity, Local/Adjacent Land Use, Water Proximity, Response to Well Incident • Well Configuration • Valve Factor

2.4. Likelihood Scoring Components

The likelihood scoring components include the following factors are a defined in the following subsections. The scoring component is shown in the shaded box within the section.

The scoring components are combined in the following equation:

Likelihood = (Usage Factor/5) + (Adjusted Rework Factor x 5)
+ (Production Casing Condition Factors)
+ (Tubing and Packer Condition Factors)
+ (Monitoring and Inspection Condition Factors)
+ (Well Security Factor)
+ (Natural Force Factors)

2.4.1. Usage Factor:

The usage factor is computed as described below:

- Usage Factor: This score considers the impact of the duration of use over a well's life cycle, the prospect for human error via intervention activities, how the well has been used to account for levels of stresses the well has been subject to.

$$\text{Usage Factor} = \text{Average}\left\{\begin{array}{c}\text{Number of Years in Operation}\\ \text{Years since last well rework}\\ 20 \times \text{Well Operation}\end{array}\right\}$$

  - Well Operation: The current operational state in which the well is used. Wells will be identified as Injection and withdrawal (Inj/Wd), withdrawal only (Wd only), or observation (obs). The use of the well is dependent on construction and surface facility installments. Wells that are used for both Inj/Wd have a higher likelihood score as the stresses from injection and withdrawal activities are the highest. Wells used for Wd only do not experience injection forces, thus are scored lower. Wells used of observation do not experience dynamic loading and are scored lower at a 1.

    The following likelihood scoring is given based on identified well operation:

    Injection/Withdrawal (IW) = 3

    Withdrawal only (wd only) = 2

    Observation (obs) = 1

2.4.3. Adjusted Rework Factor

This score is based on the knowledge of the casing condition and assigns a higher risk score to wells that have had intervention or rework activity and have not had a casing assessment performed. This accounts for the human impact and risk associated with rework activity, and elevates opportunities where the casing could have been impacted but the condition is unknown.

Rework Factor =	If casing condition not known	→	Number of Well Reworks
	If casing condition not known	→	0.5 x Number of Reworks

2.4.4. Production Casing/Inner String Condition Factor:

The production casing condition factor is a summation of the following inputs for the production casing string. In wells that have been converted to tubing and packer, this element is considered the secondary barrier.

- Original Production Casing Wall Thickness: This score is based on the worst-case metal loss identified in a casing inspection survey (i.e. MFL or ultrasonic). In the case where a well has not been assessed, the highest score is assigned.

  Unknown = 4
  Class 3 or 4 = 3
  Class 2 or general = 2
  Isolated Class 1 or 2 = 1

- Inner String Production Casing Wall Thickness: This score is based on the worst-case metal loss identified in a casing inspection survey (i.e. MFL or ultrasonic) where an inner string has been cemented into place. In the case where a well has not been assessed, the highest score is assigned.

  Unknown = 4
  Class 3 or 4 = 3
  Class 2 or general = 2
  Isolated Class 1 or 2 = 1

- Production Casing Wall Thickness: If an inner string is in place to remediate an original production casing, this pulls the inner string production casing identified

above. If the original production casing is still the active production casing string, this pulls the production casing from two items above.

Unknown = 4
Class 3 or 4 = 3
Class 2 or general = 2
Isolated Class 1 or 2 = 1

- Source of Metal Loss on Production Casing: This identifies the source of any known metal loss and assigns the score to metal loss due to corrosion as 3. For wells where the condition is unknown, the highest score of 4 is assigned to elevate the risk for wells where the condition is unknown.

Corrosion (IC or EC) = 5
Mechanical = 2
None = 0

- Potential Production Casing Mechanical Leak Path: This score identifies possible leak paths that could lead to a loss of containment incident based on the construction of a well or known historic leak prone connections. This score takes into account the well's construction and whether or not a potential leak path is present. Uncovered perforations, such that they have not been remediated with a scab liner to mitigate risk, are given a score of 5. Uncovered stage collars, those not proactively or in mitigation covered with a scab liner, also present a potential leak path and are assigned a 4. Stage collars that have been remediated with an inner string, while still can be a potential leak path, are considered less risky and a score of 3 is assigned. A casing thread leak is scored as a 2.

Uncovered Perforations = 5
Uncovered Stage collar or thread leak = 4
Isolated (by cement or Inner String) Stage Collar = 3
Isolated casing thread Leak = 2
None Identified/Not Applicable = 1

- Dogleg Severity: This score is based on the percentage of dogleg severity(DLS). DLS is considered as the combined stresses across sections of high deviation are higher and are also prone to greater amount of casing wear from pipe

tripping. The maximum % of DLS is considered in the risk score as a well with a section of pipe that has a high degree of DLS impacts the allowable stress limit of a well and reduces the amount of tolerable wall loss at the same performance rating.

0% -5% = 1
5% -10% = 2
> 10% = 3

- Inner String Installed: The presence of an inner string is included in the scoring as it adds risk by creating another potential leak path and additional element that requires monitoring.

Yes, Installed = 2
No = 1

- Cement Bond Log TOC: The cement bond log uses the input value from the TOC identifying the highest top of well bonded cement with relation to the surface casing shoe depth.

Full - 1
Inside SC - 2
Below SC - 3

2.4.5. Tubing & Packer Condition Factor

The tubing & packer condition factor is a summation of the following inputs:

- Tubing Wall Thickness: This score is based on the worst-case metal loss identified in an inspection survey (i.e. MFL or ultrasonic). This will only impact the score of wells that are converted to tubing and packer configuration.

Class 3 or 4 = 3
Class 2 or general = 2
Isolated Class 1 or 2 = 1
Not Applicable = 0

- Potential Tubing Mechanical Leak Path: This score is based on known thread leaks of the tubing.

Tubing thread Leak = 2 *None Identified/Not Applicable = 0*

- Packer Condition: This score is based on how well a packer is sealing and if a known packer leak is present.

Known Leak=2 *Sealing/Not Applicable = 0*

2.4.6. Monitoring and Inspection Condition Factors:

The following monitoring and inspection data points/trends are combined for each well evaluation:

- Annular Condition Monitoring Plan: This score uses the presence of an annular condition monitoring plan to elevate the risk of a given well.

  Note: based on the annular testing performed, annular pressure can be managed and is typically not considered a hazardous situation.

Yes = 3 *No = 1*

- Sand Production: The sand inspections of each well is typically performed twice each year during withdrawal season. This score uses the historical sand inspection data and counts the number of inspections that have been a grade 3 or higher. This elevates the risk score of a well as it can be associated with higher erosion rates and gravel pack degradation.

Count of # of Grade 3 or more that have occurred since last rework

- Gas Composition: This score takes into account the type of gas in the storage system and if corrosive constituents are present and could cause/accelerate metal loss features.

None = 0
CO_2 = 1
H_2S = 5

- Wellhead Flange Condition- known leak: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2
No= 1

- Wellhead Tubing head Condition- known leak: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2
No= 1

- Wellhead Hydraulic Port Leak Condition: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2
No= 1

- Known Hydrate Potential: This score is factored in for wells where hydrate formation on the system has been identified historically.

Yes, historically observed = 1
No= 0

2.4.8. Wellhead Security Factor

The Wellhead security factor is a summation of the following inputs:

- Well Security: This score is based on security features installed at a given wellhead site or group of proximate wellheads. This score impacts the likelihood by taking into account the presence of a barrier that would limit access, thus reducing the likelihood of an external influence triggering a loss of containment event. Wells that have a fencing system are scored with a 1 and those without any type of physical barrier limiting access would be a 2.

  All of PG&E's wellhead sites are gated and fenced.

  Gated/Fenced = 1

  No= 2

- Wellhead Surface Impact Damage Protection: This score is based on security features installed at a given wellhead site to minimize opportunity for surface impact to the wellhead to occur and lead to an uncontrolled flow event. If no measures are employed, then the highest score is assigned as the wellhead has a higher risk of exposure to surface impact (i.e. vehicular). The likelihood score is reduced based on the level of surface protection provided whether a full circumferential system (i.e.. Bollards) be in place or partial (i.e. k-rail system on one side). Wells that are enclosed by a fence but do not have a barrier in place have a higher risk as maintenance vehicles drive within the fenced area.

  Full Barricade (k-rail/bollard) =1

  Partial Barricade (k-rail/bollard) = 2

  None (Fenced only) = 3

2.4.9. Natural Force Factors

The following factors are included and take into account naturally occurring outside force threats.

- Flooding: This score is based on the potential to experience flooding at a given storage facility.

  No= 0

  Yes=1

- Seismic: This score is based on the potential seismicity a given storage facility.

Low = 1
Med = 2
High =3

- Subsidence: This score consider is there is active subsidence at the facility.

No= 0
Yes=1

- Tsunami: This score considers the opportunity for a tsunami to impact the facility.

No= 0
Yes=1

- Landslide: This score considers if the facility and well site is situated where it could be impacted by landslides.

No= 0
Yes=1

2.5. Consequence Scoring Components

The consequence scoring components include the following factors as defined in the following subsections. The scoring component is shown in the shaded box within the section.

The scoring components are combined in the following equation:

$$\text{Consequence} = [\,(0.25 \times \text{Well Rate Factor}) + (\text{Well Operation Factor}) + \Sigma\,(\text{Proximity Factors})\,] - [\,5\text{x}\,(\,(0.5\ \text{Configuration}) + (\text{Valve Factor})\,)\,]$$

2.5.2. Well Rate Factor

- Rate Factor: This is based on the max current rate at the time of publishing the risk plan. Twenty-five percent of the rating factors into the consequence score to account for the reliability impact with the loss of a well.

2.5.3. Well Operation Factor

- Well Operation: The operational consequence of an event is also impacted that renders the well unusable has a greater implication on operations and use of the storage field. Withdrawal only wells carry an intermediate scoring as the unavailability of the well poses a risk to deliverability. Observation wells are assigned the lowest value in this category as unavailability would not impose a risk to operations.

Injection/Withdrawal (IW) = 3
Withdrawal only (wd only) = 2
Observation (obs) = 1

2.5.4. Proximity Factors

- Wind Direction Impact: This score looks at a well's surface location with respect to the nearest located structure and the predominant wind direction. This score is considered high such that a large release of gas could have severe impact with ignition on an adjacent facility. The score is low such that the predominant wind direction is away from adjacent structures.

High = 3
Low = 1

- Occupied Structure: This score is based on the well's surface location and its proximity to an occupied structure.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Offset Wells: This score is based on the well's surface location and its proximity to an adjacent wellhead.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Roads: This score is based on the well's surface location and its proximity to a road as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3
0-500 ft of Major Highway = 4

- Proximity to Railroads: This score is based on the well's surface location and its proximity to a railroad as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Major Airport: This score is based on the well's surface location and its proximity to a major airport as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Population Centers: This score is based on the facility's location and the buffer rings indicated in the scoring.

> 1 Mile =3
1-2 Mile =2
2-5 Mile =1
>5 Mile = 0

- Proximity to Body of Water: This score is based on the facility's location and the buffer rings indicated in the scoring.

> 1 Mile =3
1-2 Mile =2
2-5 Mile =1
>5 Mile = 0

- Local Area/Land Use: This score is based on the facility's location and the surrounding area activity.

Urban = 4
Residential = 3
Crop farming (Irrigation/fertilizer / Plane) = 2
Cattle farming = 1

- Response to Well Incident: This score is based on proximity of employees to recognize and be able to respond in the event of a well emergency. Manned facilities have a higher likelihood that a response would be fairly soon after an event started or signs of an event could be recognized to minimize the impact.

Unmanned-2
Facility Manned-1

2.5.5. Valve Factor

This factor is used to reduce the consequence score by the mitigation employed by the presence and performance of a DHSV. The factor is computed in the following manner; each scoring component is listed and explained below.

$$\text{Valve Factor} = \left(\frac{\text{DHSV-Csg deployed}}{\text{DHSV-Csg Condition}} \right) + \left(\frac{\text{DHSV-Tbg deployed}}{\text{DHSV-Tbg Condition}} \right) + \left(\frac{1}{1 + \text{DHSV CL-cond}} \right)$$

- Well Configuration Factor: This score is used to reduce the consequence such that the dual barrier configuration would reduce the impact on the consequence.

  This score is factored by 50% in the final algorithm.

  T&C Flow -1
  T&P - 4

- DHSV Casing (Csg) Deployment: This score considers the presence of a DHSV on the casing side. Once wells are converted to tubing and packer, there is only a DHSV installed on the tubing side.

  Yes -1
  No - 0

- DHSV Tubing (Tbg) Deployment: This score considers the presence of a DHSV on the tubing side. Once wells are converted to tubing and packer, there is only a DHSV installed on the tubing side. Note: not all wells require a DHSV to be installed based on the critical well definition.

  Yes -1
  No - 0

- DHSV Casing (Csg) Condition: This score sums the number of level 4 leak by tests results a valve has received since installation.

  # of Level 4 since installation

- DHSV Tubing (Tbg) Condition: This score sums the number of level 4 leak by tests results a valve has received since installation.

  # of Level 4 since installation

- DHSV Control Line Condition: This score sums the number of level 4 leak by tests results the control line has received since installation.

  # of Level 4 since installation

3. Los Medanos Construction Standard Implementation Plan

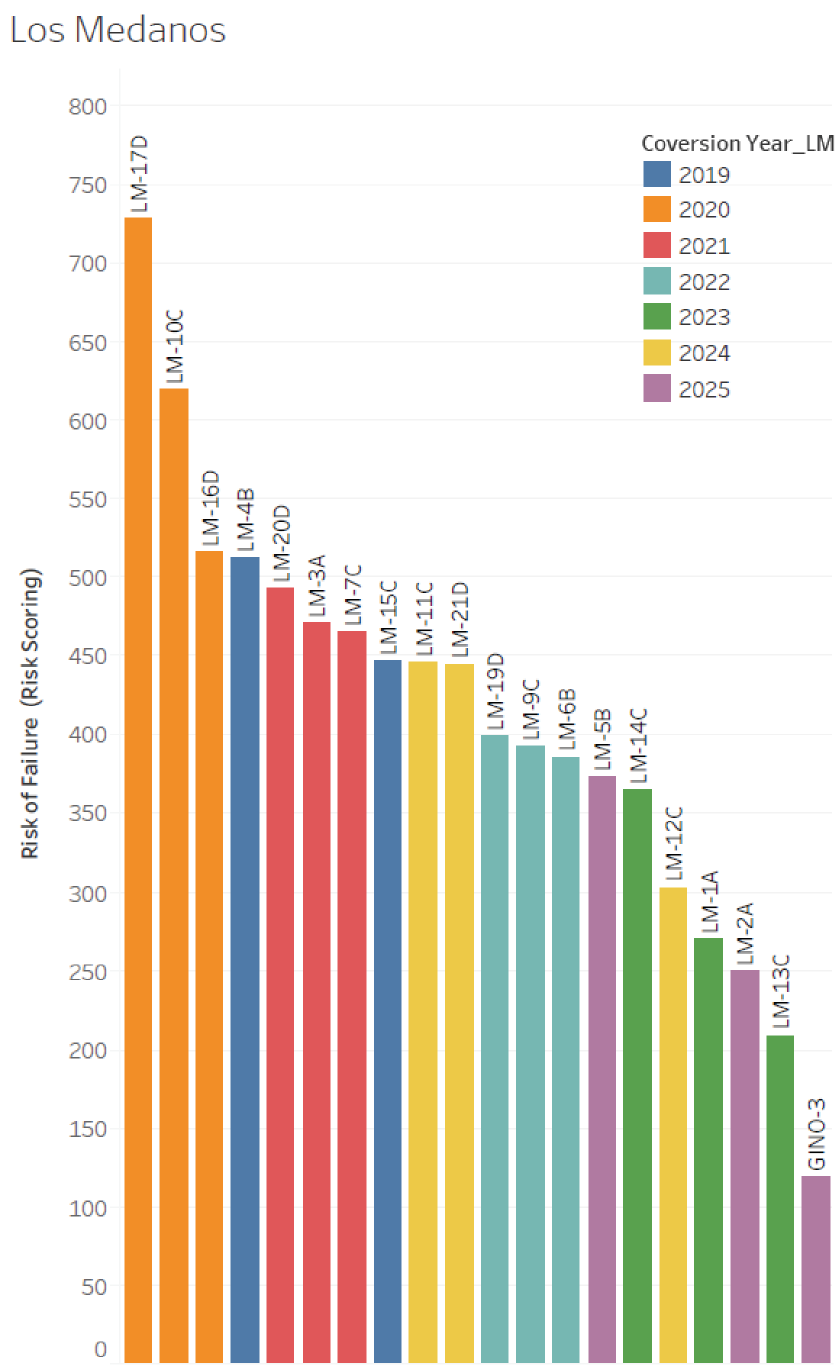
PG&E's wells located at Los Medanos are typically completed with open ended tubing and flow gas in both the tubing and casing annuli. In accordance with the construction standard in the DOGGR final regulations §1726.5, PG&E is phasing in the retrofits and/or permanent plug and abandonment as shown below in the schedule by year. Refer to the well specific schedule shown in Appendix B – Los Medanos Well Implementation and Assessment Schedule for the planned year of conversion. Additionally, Figure 3-1 shows the planned year of conversion and relative risk of a given well.

The well-by-well planned schedule is a living document and is based on the current data and inspection information known at the time this plan was published. The planned schedule is subject to change following the annual ranking update and where continuous evaluation activities necessitate advancing a well ahead of the planned date to address issues accordingly. Table 1 below shows the number of wells targeted by year to accomplish the conversion to tubing and packer configuration or plug and abandon by the end of 2025.

Table 1

Los Medanos 2019-2025 Well Construction Standard Implementation Plan			
Year	**Planned Number of Wells**	**% of Total Wells**	**Cumulative Count**
2018	0	0	1*
2019	2	10%	3
2020	3	15%	6
2021	3	15%	9
2022	3	15%	12
2023	3	15%	15
2024	3	15%	18
2025	2	10%	20
*Note: One well at Los Medanos was completed with T&P prior to the regulations.			

Figure 3-1: T&P Conversion shown by year and Risk Rank



4. Baseline and Reassessment Schedule & Methodology for Casing Inspection

PG&E commenced performing baseline inspections in 2013 and has completed a baseline casing inspection log on 6 wells (30% of field) at the start of 2019. As the program advanced, additional logs and tests were grouped into the suite of testing to establish a baseline in 2016. The suite of testing is provided in the Risk and Integrity Management Plan in Appendix Z. The status of well assessments can be grouped into three categories based on the time period when the assessment occurred:

1. **Pending Assessments:** Wells have not yet been inspected using advanced casing inspection tools. These wells have been inspected for baseline gas behind pipe using GRN tools. The wells have continued to be monitored annually via noise and temp (N&T) inspection. Additional daily and weekly monitoring activities (i.e. leak inspection and annular pressure monitoring) have been performed in alignment with the Risk and Integrity Management Plan Practices.

2. **Pre-2016 Assessments:** Wells were typically assessed using MFL tools for inspections, GRN tools during well work and also were monitored using the noise & temperature tools (N&T) annually. Additional daily and weekly monitoring activities (i.e. leak inspection and annular pressure monitoring) have been performed in alignment with the Risk and Integrity Management Plan Practices.

3. **2016-Current Assessments:** Wells were assessed using the full suite of inspections including MFL, CBL, N&T, GRN/RST, ultrasonic, caliper, and pressure testing. Additional daily and weekly monitoring activities (i.e. leak inspection and annular pressure monitoring) have been performed in alignment with the Risk and Integrity Management Plan Practices.

A key finding from the groups of wells that have casing assessment data demonstrates that current field conditions at Los Medanos do not appear indicate active corrosion is present. Inspection data from MFL and ultrasonic support the conclusion that neither internal or external corrosion appear to be prevalent or common at this time. PG&E uses the guidance in Appendix C of the Risk and Integrity Management Plan to determine the reinspection frequency for a given well following a baseline or reinspection of casing condition. The typical casing frequency return period continues to fall into “12-15 year” re-assessment window based on limited metal loss (class 3 and below) and isolated condition. PG&E will be returning to the well that was previously assessed for conversion to tubing and packer ahead of follow up inspection and planned reassessment period.

PG&E plans to complete the remainder of the baseline inspections at Los Medanos during the well conversion to tubing and packer configuration. PG&E uses a methodology that is prioritized by risk and coupled with the ability to effectively and efficiently conduct the work, minimization of unnecessary equipment mobilization, and coordination with station projects (i.e. pipeline work, platform equipment maintenance/rebuilds) to reduce impact to deliverability and station outage. Figure 4-1 maps this approach and uses the results of the risk model, PG&E prioritizes the wells in the based on the risk score and looks at each of the following categories:

1. **Assessment Status of "Pending**": wells pending assessment are targeted in the first group to be converted to tubing and packer configuration. During that conversion activities, wells will be inspected using the full suite of inspection tools identified in Appendix Z.

2. **Assessment Status "Pre-2016"**: wells that are slated for re-inspection following their baseline metal thickness inspection will be targeted

3. **Assessment Status "2016- Current":** These wells have been evaluated using the full suite of logs in Appendix Z. Wells in this category typically have a re-assessment internal of 12-15years and PG&E will be returning to these wells to reconfigure them in a tubing and packer status ahead of the targeted re-assessment interval.

Using this approach, all wells at Los Medanos will have had an initial baseline casing condition inspection by the end of 2023. Additionally, PG&E plans to run a thru-tubing casing inspection log on wells that are pending assessment and not planned for work in 2020. This logging activity will continue every two years until the well has been assessed. This allows PG&E to identify if any of the wells pending assessment have any features that require remediation ahead of the planned schedule and can advance those wells accordingly. Further, for wells that have been previously assessed with a casing inspection, a thru-tubing surveillance logging program will commence in 2020 and cycle every two years until the well is converted to tubing and packer. The planned frequency for each group is also show in Figure 4-1.

Following a well's baseline inspection and/or conversion to tubing and packer, PG&E will identify the well's casing reassessment frequency per Appendix C of the Risk and Integrity Management Plan. PG&E plans to deploy a casing inspection surveillance program using thru-tubing technology to monitor for any changes in condition; note, this surveillance activity is in addition to the routine integrity monitoring practice (i.e. sand inspection, pressure monitoring, annual noise and temperature survey).

Figure 4-2 illustrates the frequency of the thru-tubing inspection and pressure testing, per Appendix K of Risk and Integrity Management Plan. After the first two cycles of thru-tubing logging are performed, PG&E will space the 3rd logging activity halfway between the next planned reassessment. For example, a well scheduled on a 12-15 year reassessment interval will have a thru-tubing log run in year 2 and year 4 following conversion to T&P. The next thru-tubing log will be run in year 8, halfway between year 4 and year 12.

Figure 4-1: Assessment in Year & T&P Conversion Risk Informed Methodology

Year of Assessment	Assessment in Year & T&P Conversion						
	2019	2020	2021	2022	2023	2024	2025
Pending	2019 Planned Wells: Full Assessment with T&P Conversion						
Pending	N&T	2020 Full Assessment with T&P Conversion					
Pending	N&T Thru - Tubing	N&T	2021 Full Assessment with T&P Conversion				
Pending	N&T Thru - Tubing	N&T	N&T Thru - Tubing	2022 Full Assessment with T&P Conversion			
Pending	N&T Thru - Tubing	N&T	N&T Thru - Tubing	N&T	2023 Full Assessment with T&P Conversion		
2013 – mid 2016	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	2023 Full Assessment with T&P Conversion		
2013 – mid 2016	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T	2024 Full Assessment with T&P Conversion	
2016 – 2018	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T	2025 Full Assessment with T&P Conversion	
2016 – 2018	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T	N&T Thru- Tubing	Full Assessment with T&P Conversion

Figure 4-2: Assessments performed in Year Following T&P Conversion

Re-Assessment Interval	Assessment in Year Following T&P Conversion														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
3-5 Years	N&T	N&T	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval												
5-8 Years	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval										
8-12 Years	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T Pressure Testing	N&T	N&T	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval							
12-15 Years	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T Pressure Testing	N&T	N&T	N&T Thru Tubing	N&T	N&T Pressure Testing	N&T	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval			

Appendix A – Los Medanos Relative Risk Well Evaluation

Figure A-1: Well by Well Risk of Failure Scoring – Los Medanos

**Note: The consequence scoring chart above shows a black line serving as the "zero" axis as the score components graphed below are mitigation components and reduce consequence.

Table 2 – Los Medanos Risk Evaluation (Input Data)

Well Name	API	Well Operation IW Wd only OBS	Well Operation IW = 3 Wd only = 2 OBS = 1	Spud Date	Completion Date	Years in Operation	Year of last Well Rework	Years since last Well Rework	# of Well Rework Performed	Measured Cement Bond Log TOC (feet)	Surface Csg (SC) Shoe, ft	Est. Distance to nearest offset well (feet)	Proximity to Roads (feet)	Proximity to Railroad (feet)	Proximity to Major Airport (feet)	Distance to Occupied Sturcture (HCA / Residence / Employee office-RE/Contrl Room building) (feet)	Proximity to Water (feet)
LM-17D	01320136	**WD**	2	1/31/1979	2/28/1979	40	1997	22	1	0	913	87	3,054	5000	5000	840	8484
LM-10C	01320131	**I/W**	3	7/21/1978	9/29/1978	41	2003	16	1	2136	524	69	3,956	5000	5000	1614	9386
LM-16D	01320133	**I/W**	3	9/30/1978	10/22/1978	41	2004	15	1	0	932	117	3,027	5000	5000	764	8457
LM-4B	01320093	**WD**	2	7/17/1973	8/13/1973	46	2013	6	5	1518	1198	15	5,222	5000	5000	2722	10652
LM-20D	01320297	**WD**	2	6/5/1990	8/31/1990	29	1990	29	0	0	764	107	2,941	5000	5000	715	8371
LM-3A	01320115	**I/W**	3	10/17/1977	12/9/1977	41	2000	19	3	625	910	79	6,423	5000	5000	3945	11853
LM-7C	01320130	**I/W**	3	5/25/1978	7/19/1978	41	1992	27	1	720	902	157	4,213	5000	5000	1856	9643
LM-15C	01320121	**WD**	2	12/12/1977	2/4/1978	41	1999	20	3	3779	893	82	3,883	5000	5000	1573	9313
LM-11C	01320128	**I/W**	3	3/17/1978	5/24/1978	41	2015	4	2	100	898	145	3,887	5000	5000	1541	9317
LM-21D	01320308	**I/W**	3	5/6/1991	5/28/1991	28	2015	4	3	250	885	85	3,013	5000	5000	899	8443
LM-19D	01320295	**I/W**	3	5/23/1990	7/30/1990	29	2007	12	1	1200	756	104	2,962	5000	5000	898	8392
LM-9C	01320123	**I/W**	3	2/7/1978	3/10/1978	41	2011	8	2	1525	891	69	4,030	5000	5000	1682	9460
LM-6B	01320140	**I/W**	3	12/20/1978	1/31/1979	40	2006	13	1	386	877	82	5,237	5000	5000	2738	10667
LM-5B	01320144	**I/W**	3	3/1/1979	4/2/1979	40	2013	6	1	407	501	124	5,206	5000	5000	2750	10636
LM-14C	01320298	**I/W**	3	6/19/1990	9/21/1990	29	1990	29	0	0	495	58	3,941	5000	5000	1628	9371
LM-12C	01320307	**I/W**	3	4/15/1991	6/10/1991	28	2016	3	1	780	913	69	4,068	5000	5000	1750	9498
LM-1A	01320373	**OBS**	1	11/25/2007	12/16/2007	11	2007	12	0	890	901	44	6,422	5000	5000	3971	11852
LM-2A	01320138	**I/W**	3	11/14/1978	12/14/1978	40	2016	3	2	1570	920	85	6,453	5000	5000	3988	11883
LM-13C	01320299	**I/W**	3	7/7/1990	10/2/1990	29	1990	29	0	0	770	58	3,999	5000	5000	1686	9429
GINO-3	01300135	**OBS**	1	12/7/1961	2/2/1962	57	2017	2	3	0	2553	114	6,466	5000	5000	4014	11896

Table 3 – Los Medanos Risk Evaluation (Likelihood Data)

Well Name	Well Operation IW = 3 (Likelihood) Wd only = 2 OBS = 1	Usage Factor	Adjusted # of Well Reworks	Original Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Inner String Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Source of Metal Loss on Production Casing Unknown = 4 Corrosion = 3 Mechanical = 2 None = 0	Potential Production Casing Mechanical Leak Path Uncovered Perforations = 5 Uncovered Stage collar = 4 Isolated (by cement or Inner String) Stage Collar = 3 Casing thread Leak = 2 None Identified/Not Applicable = 1	Dogleg Severity 0-5 %= 1 5-10% = 2 >10% = 3	Inner String Installed Yes -2 No -1	Cement Bond Log TOC Full - 1 Inside SC - 2 Below SC - 3
LM-17D	2	34	1	4	0	4	4	1	2	1	1
LM-10C	3	39	1	4	0	4	4	3	2	1	3
LM-16D	3	39	1	4	0	4	4	1	2	1	1
LM-4B	2	31	2.5	2	0	2	2	3	0	1	3
LM-20D	2	33	0	4	0	4	4	1	0	1	1
LM-3A	3	40	3	4	0	4	4	1	2	1	2
LM-7C	3	43	1	4	0	4	4	1	3	1	2
LM-15C	2	34	3	4	0	4	4	3	2	1	3
LM-11C	3	35	1	2	0	2	2	1	2	1	2
LM-21D	3	31	1.5	1	0	1	0	1	0	1	2
LM-19D	3	34	1	4	0	4	4	1	0	1	3
LM-9C	3	36	2	4	0	4	4	1	2	1	3
LM-6B	3	38	1	4	0	4	4	1	2	1	2
LM-5B	3	35	0.5	3	0	3	2	1	2	1	2
LM-14C	3	39	0	4	0	4	4	1	0	1	1
LM-12C	3	30	0.5	2	0	2	2	1	2	1	2
LM-1A	1	14	0	4	0	4	4	1	0	1	2
LM-2A	3	34	1	2	0	2	2	1	2	1	3
LM-13C	3	39	0	4	0	4	4	1	0	1	1
GINO-3	1	26	1.5	3	0	3	2	1	0	1	1

Table 4 – Los Medanos Risk Evaluation (Likelihood Data - Cont)

Well Name	**Tubing Wall Thickness** Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1 Not Applicable = 0	**Potential Tubing Mechanical Leak Path** Tubing thread Leak = 2 None Identified/Not Applicable = 0	**Packer Condition** Known Leak=2 Sealing/Not Applicable = 0	**Annular Condition Monitoring Plan In Place** Yes - 3 No - 1	**Sand Production** # of Grade 3 or more since last rework	**Gas Composition** None = 0 CO2 = 1 H2S = 5	**Wellhead Tbg Head Condition - Known Leak** Yes - 2 No- 1	**Wellhead flange Condition - Known Leak** Yes - 2 No - 1	**Wellhead hydraulic Port leak** Yes -2 No- 1	**Known Hydrate Formation** No = 0 Yes = 1
LM-17D	0	0	0	1	0	0	2	1	1	0
LM-10C	0	0	0	1	0	0	2	1	1	0
LM-16D	0	0	0	1	0	0	2	1	1	0
LM-4B	0	0	0	3	0	0	1	1	1	0
LM-20D	0	0	0	1	0	0	2	1	1	0
LM-3A	0	0	0	1	0	0	2	1	1	0
LM-7C	0	0	0	1	0	0	1	1	2	0
LM-15C	0	0	0	1	0	0	2	1	1	0
LM-11C	0	0	0	1	1	0	1	1	1	0
LM-21D	0	0	0	1	0	0	1	1	1	0
LM-19D	0	0	0	1	0	0	2	1	1	0
LM-9C	0	0	0	1	0	0	1	1	1	0
LM-6B	0	0	0	3	0	0	2	1	2	0
LM-5B	0	0	0	1	0	0	1	1	1	0
LM-14C	0	0	0	1	0	0	2	1	1	0
LM-12C	0	0	0	1	0	0	1	1	1	0
LM-1A	0	0	0	1	0	0	1	1	1	0
LM-2A	0	0	0	1	0	0	1	1	1	0
LM-13C	0	0	0	1	0	0	2	1	1	0
GINO-3	0	0	0	1	0	0	1	1	1	0

Table 5 – Los Medanos Risk Evaluation (Likelihood Data - Cont)

Well Name	Well Security Gated/fenced = 1 No = 2	Wellhead Surface Damage Protection **Full** Barricade (k-rail/bollard) =1, **Partial** Barricade (k-rail/bollard) = 2 **None** (Fenced only) = 3	Natural Force Flooding No= 0 Yes = 1	Natural Force Seismic Low PGA = 1 Med PGA = 2 High PGA =3	Natural Force Subsidence No= 0 Yes = 1	Natural Force Tsunami No= 0 Yes= 1	Natural Force Lanslide No= 0 Yes = 1
LM-17D	1	1	0	3	0	0	0
LM-10C	1	1	0	3	0	0	0
LM-16D	1	1	0	3	0	0	0
LM-4B	1	1	0	3	0	0	0
LM-20D	1	1	0	3	0	0	0
LM-3A	1	1	0	3	0	0	0
LM-7C	1	1	0	3	0	0	0
LM-15C	1	1	0	3	0	0	0
LM-11C	1	1	0	3	0	0	0
LM-21D	1	1	0	3	0	0	0
LM-19D	1	1	0	3	0	0	0
LM-9C	1	1	0	3	0	0	0
LM-6B	1	1	0	3	0	0	0
LM-5B	1	1	0	3	0	0	0
LM-14C	1	1	0	3	0	0	0
LM-12C	1	1	0	3	0	0	0
LM-1A	1	1	0	3	0	0	0
LM-2A	1	1	0	3	0	0	0
LM-13C	1	1	0	3	0	0	0
GINO-3	1	1	0	3	0	0	0

Table 6 – Los Medanos Risk Evaluation (Consequence Data)

Well Name	**Max Rate** MMcf/d	**Well Operation** IW = 3 (Consequence) Wd only = 2 OBS = 1	**Wind Direction Impact** High - 3 Low - 1	**Occupied Sturcture** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Offset wells Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Roads Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 0-500 ft of Major Highway = 4	**Proximity to Railroad Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Proximity to Major Airport** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	**Population Centers** > 1 Mile =3 1-2 Mile =2 2-5 Mile =1 >5 Mile = 0	**Proximity to Body of Water Score** >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 Water Well = 4, Navigable Waterway = 5	**Local Area Activities/Land Use** Urban = 4 Residential = 3 Crop farming (Irrigation/fertilizer / Plane) = 2 Cattle farming = 1	**Response to Well Incident** Unmanned-2 Facility Manned-1
LM-17D	30	2	3	2	3	1	1	1	2	1	1	1
LM-10C	20	3	1	1	3	1	1	1	2	1	1	1
LM-16D	14	3	3	2	3	1	1	1	2	1	1	1
LM-4B	26	2	1	1	3	1	1	1	2	1	1	1
LM-20D	23	2	3	2	3	1	1	1	2	1	1	1
LM-3A	26	3	1	1	3	1	1	1	2	1	1	1
LM-7C	21	3	1	1	3	1	1	1	2	1	1	1
LM-15C	0	2	1	1	3	1	1	1	2	1	1	1
LM-11C	15	3	1	1	3	1	1	1	2	1	1	1
LM-21D	15	3	3	2	3	1	1	1	2	1	1	1
LM-19D	20	3	3	2	3	1	1	1	2	1	1	1
LM-9C	24	3	1	1	3	1	1	1	2	1	1	1
LM-6B	15	3	1	1	3	1	1	1	2	1	1	1
LM-5B	17	3	1	1	3	1	1	1	2	1	1	1
LM-14C	20	3	1	1	3	1	1	1	2	1	1	1
LM-12C	20	3	1	1	3	1	1	1	2	1	1	1
LM-1A	0	1	1	1	3	1	1	1	2	1	1	1
LM-2A	17	3	1	1	3	1	1	1	2	1	1	1
LM-13C	15	3	1	1	3	1	1	1	2	1	1	1
GINO-3	0	1	1	1	3	1	1	1	2	1	1	1

Table 7 – Los Medanos Risk Evaluation (Consequence Data)

Well Name	Configuration T&C Flow -1 T&P - 4	DHSV Csg Deployment Yes -1 No- 0	DHSV Tbg Deployment Yes -1 No- 0	DHSV Tbg Condition # of Level 4 since installation	DHSV Csg Condition # of Level 4 since installation	DHSV Control Line Condition # of Level 4 since installation	Valve Factor	Likehood of Failure	Consequence of Failure	Risk of Failure (Risk Scoring)
LM-17D	1	1	1	1	2	1	0.42	35	21	728
LM-10C	1	1	1	0	5	1	0.58	40	16	620
LM-16D	1	1	1	0	8	0	1.11	36	14	516
LM-4B	1	1	1	3	0	0	1.25	41	13	513
LM-20D	1	1	1	0	0	2	0.67	28	18	493
LM-3A	1	1	1	0	0	0	2.00	47	10	470
LM-7C	1	1	1	0	2	0	1.33	39	12	466
LM-15C	1	1	1	2	0	1	0.67	49	9	447
LM-11C	1	1	1	2	0	1	0.67	32	14	445
LM-21D	1	1	1	2	1	0	0.83	28	16	444
LM-19D	1	1	1	0	0	0	2.00	35	12	399
LM-9C	1	1	1	0	0	0	2.00	41	10	392
LM-6B	1	1	1	1	0	0	1.50	40	10	386
LM-5B	1	1	1	1	1	0	1.00	30	13	373
LM-14C	1	1	1	5	0	0	1.17	29	13	365
LM-12C	1	1	1	1	0	0	1.50	28	11	303
LM-1A	1	1	0	1	1	11	0.04	24	11	270
LM-2A	1	1	1	0	0	0	2.00	32	8	249
LM-13C	1	1	1	0	0	0	2.00	29	7	209
GINO-3	4	0	0	0	0	0	-	30	4	119

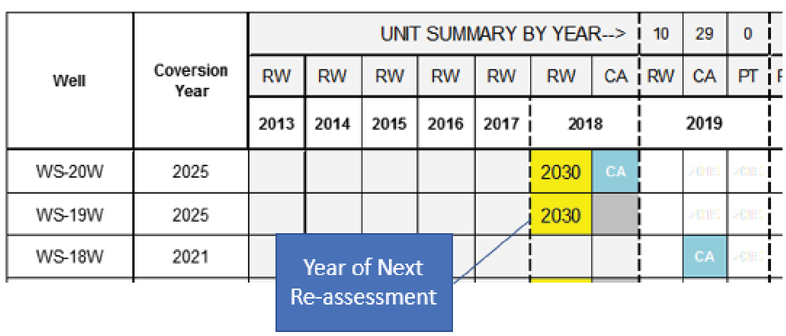
Appendix B - Los Medanos Well Construction Standard Implementation Plan and Assessment Schedule

The following figures provide an overview of the applied methodology from Section 4 that includes conversion of PG&E’s wells to tubing and packer and brings them into conformance with §1726.5 of the final regulations put forth by the Division. Additionally, the figures demonstrate the assessment methodology – both pre- and post-conversion to tubing and packer configuration. The plan shown below for each well is based on addressing wells with the highest risk identified in the risk analysis shown in Appendix A. The planned schedules in the following figures are based on current data in the risk model. As new monitoring data is received, the plan below is subject to change.

The charts below show three possible activities for each well by year from 2019 thru 2025:

1. Thru-tubing casing assessment (blue)
2. T&P conversion/full assessment (green)
3. 5-year re-assessment pressure test (purple)

Additionally, for wells previously assessed, the schedule is shaded with yellow and the planned reassessment year based on casing condition observed is noted.



For wells previously assessed, the decision to run a third thru-tubing log will rest with PG&E Reservoir Engineering following review of 2 sequential cycles thru-tubing logging results; note Example 1 shown below.

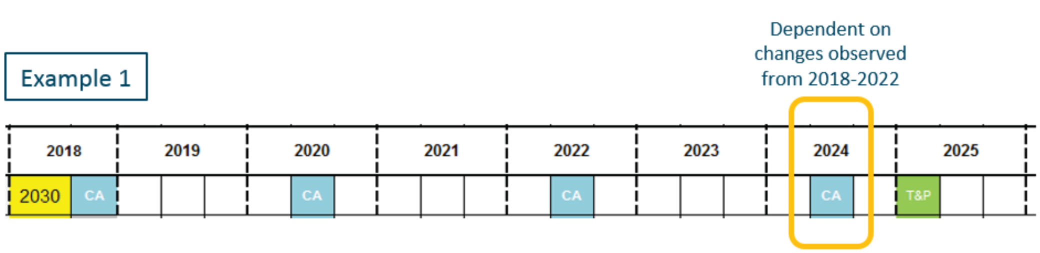


Figure B.1: Well Implementation and Assessment Schedule – Los Medanos

Well	Coversion Year	UNIT SUMMARY BY YEAR-->							2	9	0	3	6	0	3	7	0	3	9	0	3	4	0	3	9	1	3	6	3
		RW	RW	RW	RW	RW	RW	CA	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT	RW	CA	PT
		2013	2014	2015	2016	2017	2018		2019			2020			2021			2022			2023			2024			2025		
GINO-3	2025					2025							CA						CA						CA		T&P		
LM-1A	2023									CA						CA					T&P							CA	
LM-2A	2025				2028								CA						CA						CA		T&P		
LM-3A	2021									CA					T&P							CA						CA	
LM-4B	2019	2025							P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A
LM-5B	2025	2021											CA						CA						CA		T&P		
LM-6B	2022									CA						CA		T&P							CA				
LM-10C	2020											T&P							CA						CA				PT
LM-11C	2024	2027											CA						CA					T&P					
LM-12C	2024				2028								CA						CA					T&P					
LM-13C	2023									CA						CA					T&P							CA	
LM-14C	2023									CA						CA					T&P							CA	
LM-15C	2019								T&P							CA						CA				PT			
LM-7C	2021									CA					T&P							CA						CA	
LM-9C	2022									CA						CA		T&P							CA				
LM-16D	2020											T&P							CA						CA				PT
LM-17D	2020											T&P							CA						CA				PT
LM-19D	2022									CA						CA		T&P							CA				
LM-20D	2021									CA					T&P							CA						CA	
LM-21D	2024												CA						CA					T&P					

Legend

RW Casing Assessment	Year of Relog
Thru-Tubing Casing Assessment	CA
Tubing & Packer Conversion Rework	T&P
Pressure Test (T&P)	PT
Reinspection Rework	RW
Plug & Abandon	P&A

Pacific Gas and Electric Company

Pleasant Creek Underground Storage Field: Well Risk Evaluation and Construction Standard Implementation Plan

Gas Storage Asset Management Department

Publication Date: March 29, 2019

Table of Contents

1. Introduction

This plan provides the applied individual well risk assessment as detailed in PG&E's Underground Storage Risk and Integrity Management Plan and is specific to the Pleasant Creek Storage Field Facility wells. This plan is a companion document to the Underground Storage Risk and Integrity Management Plan and is intended to be used in conjunction with the preventative and mitigation (P&M) measures included in the noted plan.

Under the Interim Final Rule (effective January 2017) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and API RP 1171 incorporated by reference, operators shall develop a program to manage risk that includes a process to assess risk related to the storage operation on a consistent basis. Additionally, under the Final Regulations (effective October 2018) issued by Division of Oil, Gas, and Geothermal Resources (DOGGR) require operators to perform a risk assessment on a well-by-well basis (§1726.3(c)(2)(4)).

Contained within this implementation plan is the planned schedule to convert PG&E's storage wells at Pleasant Creek to conform with the construction requirements of dual barriers required in Final Regulations (effective October 2018) issued by Division of Oil, Gas, and Geothermal Resources (DOGGR).

Lastly, this plan provides the performance based reassessment methodology and plan for wells following baseline and subsequent inspections.

2. Relative Risk Well Model Approach and Data Sources

Individual well-by-well risk ranking allows PG&E to manage P&M programs to adequately address highest risk assets and prioritize capital projects accordingly. The relative risk ranking model database manages and tracks the inputs, both static and dynamic, to evaluate the relative risk of each well.

Continuous Evaluation (CE) is used to evaluate the integrity of each well based on data integration from both integrity assessments performed and routine maintenance, operations, and testing performed to evaluate asset condition and subsequent risk profile. Data collected from the P&M measures are used to inform the scoring assignments. Additionally, baseline casing assessment and reinspection data are input into the model. Reinspection frequency is based on the Underground Storage Risk and Integrity Management Plan, Appendix C – Casing Inspection Survey Frequency Tree.

2.1. Roles and Responsibilities

Reservoir Engineering is responsible for analyzing all the available asset data collected in the practices outlined in the Underground Storage Risk & Integrity Management Plan to evaluate the overall condition and exposure of each well asset.

2.2. Publication Schedule of the Relative Risk Model

The model is maintained throughout the year as new data becomes available and the following schedule guides the formal publication/snapshot of the relative risk model.

Publication	Purpose
By July 31	Identifies/confirms well population scheduled for next two-year rework cycles
By January 31	Integrates previous season rework Integrates year end data to identify any emergent or break in work to be addressed in the coming year and confirms five-year outlook

2.3. Relative Risk Model Attributes Inputs

The following sections below outline the various attributes and inputs that are considered in the relative risk ranking analysis. The data includes both static and dynamic data; static data is unchanging and does not require annual review, whereas dynamic data is dependent on testing result inputs.

The risk score for each well is computed by summing the score components that impact likelihood of loss of containment and multiplying that value by the sum of the consequence score impacts to safety, environment, and reliability.

Likelihood Score Components	Consequence Score Components
• Usage Factor • Adjusted Rework Factor • Production Casing Condition Factor • Tubing and Packer Condition Factor • Monitoring and Inspection Condition Factor • Wellhead Security Factor • Natural Force Factor	• Well Rate Factor • Well Operation Factor • Wind Direction Impact • Proximity Factors: Occupied Structure, Offset Well, Road and Railway Proximity, Local/Adjacent Land Use, Water Proximity, Response to Well Incident • Well Configuration • Valve Factor

2.4. Likelihood Scoring Components

The likelihood scoring components include the following factors are a defined in the following subsections. The scoring component is shown in the shaded box within the section.

The scoring components are combined in the following equation:

Likelihood = (Usage Factor/5) + (Adjusted Rework Factor x 5)
+ (Production Casing Condition Factors)
+ (Tubing and Packer Condition Factors)
+ (Monitoring and Inspection Condition Factors)
+ (Well Security Factor)
+ (Natural Force Factors)

2.4.1. Usage Factor:

The usage factor is computed as described below:

- Usage Factor: This score considers the impact of the duration of use over a well's life cycle, the prospect for human error via intervention activities, how the well has been used to account for levels of stresses the well has been subject to.

$$\text{Usage Factor} = \text{Average}\left\{\begin{array}{c}\text{Number of Years in Operation}\\ \text{Years since last well rework}\\ 20 \times \text{Well Operation}\end{array}\right\}$$

  - Well Operation: The current operational state in which the well is used. Wells will be identified as Injection and withdrawal (Inj/Wd), withdrawal only (Wd only), or observation (obs). The use of the well is dependent on construction and surface facility installments. Wells that are used for both Inj/Wd have a higher likelihood score as the stresses from injection and withdrawal activities are the highest. Wells used for Wd only do not experience injection forces, thus are scored lower. Wells used of observation do not experience dynamic loading and are scored lower at a 1.

    The following likelihood scoring is given based on identified well operation:

    Injection/Withdrawal (IW) = 3

    Withdrawal only (wd only) = 2

    Observation (obs) = 1

2.4.3. Adjusted Rework Factor

This score is based on the knowledge of the casing condition and assigns a higher risk score to wells that have had intervention or rework activity and have not had a casing assessment performed. This accounts for the human impact and risk associated with rework activity, and elevates opportunities where the casing could have been impacted but the condition is unknown.

Rework Factor =	If casing condition not known	→	Number of Well Reworks
	If casing condition not known	→	0.5 x Number of Reworks

2.4.4. Production Casing/Inner String Condition Factor:

The production casing condition factor is a summation of the following inputs for the production casing string. In wells that have been converted to tubing and packer, this element is considered the secondary barrier.

- Original Production Casing Wall Thickness: This score is based on the worst-case metal loss identified in a casing inspection survey (i.e. MFL or ultrasonic). In the case where a well has not been assessed, the highest score is assigned.

  Unknown = 4
  Class 3 or 4 = 3
  Class 2 or general = 2
  Isolated Class 1 or 2 = 1

- Inner String Production Casing Wall Thickness: This score is based on the worst-case metal loss identified in a casing inspection survey (i.e. MFL or ultrasonic) where an inner string has been cemented into place. In the case where a well has not been assessed, the highest score is assigned.

  Unknown = 4
  Class 3 or 4 = 3
  Class 2 or general = 2
  Isolated Class 1 or 2 = 1

- Production Casing Wall Thickness: If an inner string is in place to remediate an original production casing, this pulls the inner string production casing identified

above. If the original production casing is still the active production casing string, this pulls the production casing from two items above.

Unknown = 4
Class 3 or 4 = 3
Class 2 or general = 2
Isolated Class 1 or 2 = 1

- Source of Metal Loss on Production Casing: This identifies the source of any known metal loss and assigns the score to metal loss due to corrosion as 3. For wells where the condition is unknown, the highest score of 4 is assigned to elevate the risk for wells where the condition is unknown.

Corrosion (IC or EC) = 5
Mechanical = 2
None = 0

- Potential Production Casing Mechanical Leak Path: This score identifies possible leak paths that could lead to a loss of containment incident based on the construction of a well or known historic leak prone connections. This score takes into account the well's construction and whether or not a potential leak path is present. Uncovered perforations, such that they have not been remediated with a scab liner to mitigate risk, are given a score of 5. Uncovered stage collars, those not proactively or in mitigation covered with a scab liner, also present a potential leak path and are assigned a 4. Stage collars that have been remediated with an inner string, while still can be a potential leak path, are considered less risky and a score of 3 is assigned. A casing thread leak is scored as a 2.

Uncovered Perforations = 5
Uncovered Stage collar or thread leak = 4
Isolated (by cement or Inner String) Stage Collar = 3
Isolated casing thread Leak = 2
None Identified/Not Applicable = 1

- Dogleg Severity: This score is based on the percentage of dogleg severity(DLS). DLS is considered as the combined stresses across sections of high deviation are higher and are also prone to greater amount of casing wear from pipe

tripping. The maximum % of DLS is considered in the risk score as a well with a section of pipe that has a high degree of DLS impacts the allowable stress limit of a well and reduces the amount of tolerable wall loss at the same performance rating.

0% -5% = 1
5% -10% = 2
> 10% = 3

- Inner String Installed: The presence of an inner string is included in the scoring as it adds risk by creating another potential leak path and additional element that requires monitoring.

Yes, Installed = 2
No = 1

- Cement Bond Log TOC: The cement bond log uses the input value from the TOC identifying the highest top of well bonded cement with relation to the surface casing shoe depth.

Full - 1
Inside SC - 2
Below SC - 3

2.4.5. Tubing & Packer Condition Factor

The tubing & packer condition factor is a summation of the following inputs:

- Tubing Wall Thickness: This score is based on the worst-case metal loss identified in an inspection survey (i.e. MFL or ultrasonic). This will only impact the score of wells that are converted to tubing and packer configuration.

Class 3 or 4 = 3
Class 2 or general = 2
Isolated Class 1 or 2 = 1
Not Applicable = 0

- Potential Tubing Mechanical Leak Path: This score is based on known thread leaks of the tubing.

> *Tubing thread Leak = 2*
>
> *None Identified/Not Applicable = 0*

- Packer Condition: This score is based on how well a packer is sealing and if a known packer leak is present.

> *Known Leak=2*
>
> *Sealing/Not Applicable = 0*

2.4.6. Monitoring and Inspection Condition Factors:

The following monitoring and inspection data points/trends are combined for each well evaluation:

- Annular Condition Monitoring Plan: This score uses the presence of an annular condition monitoring plan to elevate the risk of a given well.

  Note: based on the annular testing performed, annular pressure can be managed and is typically not considered a hazardous situation.

> *Yes = 3*
>
> *No = 1*

- Sand Production: The sand inspections of each well is typically performed twice each year during withdrawal season. This score uses the historical sand inspection data and counts the number of inspections that have been a grade 3 or higher. This elevates the risk score of a well as it can be associated with higher erosion rates and gravel pack degradation.

> *Count of # of Grade 3 or more that have occurred since last rework*

- Gas Composition: This score takes into account the type of gas in the storage system and if corrosive constituents are present and could cause/accelerate metal loss features.

None = 0
CO2 = 1
H2S = 5

- Wellhead Flange Condition- known leak: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2
No= 1

- Wellhead Tubing head Condition- known leak: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2
No= 1

- Wellhead Hydraulic Port Leak Condition: This score uses the monitoring data from the quarterly wellhead inspections and identify if there are known leaks.

Yes, leak = 2
No= 1

- Known Hydrate Potential: This score is factored in for wells where hydrate formation on the system has been identified historically.

Yes, historically observed = 1
No= 0

2.4.8. Wellhead Security Factor

The Wellhead security factor is a summation of the following inputs:

- Well Security: This score is based on security features installed at a given wellhead site or group of proximate wellheads. This score impacts the likelihood by taking into account the presence of a barrier that would limit access, thus reducing the likelihood of an external influence triggering a loss of containment event. Wells that have a fencing system are scored with a 1 and those without any type of physical barrier limiting access would be a 2.

  All of PG&E's wellhead sites are gated and fenced.

  Gated/Fenced = 1

  No= 2

- Wellhead Surface Impact Damage Protection: This score is based on security features installed at a given wellhead site to minimize opportunity for surface impact to the wellhead to occur and lead to an uncontrolled flow event. If no measures are employed, then the highest score is assigned as the wellhead has a higher risk of exposure to surface impact (i.e. vehicular). The likelihood score is reduced based on the level of surface protection provided whether a full circumferential system (i.e.. Bollards) be in place or partial (i.e. k-rail system on one side). Wells that are enclosed by a fence but do not have a barrier in place have a higher risk as maintenance vehicles drive within the fenced area.

  Full Barricade (k-rail/bollard) =1

  Partial Barricade (k-rail/bollard) = 2

  None (Fenced only) = 3

2.4.1. Natural Force Factors

The following factors are included and take into account naturally occurring outside force threats.

- Flooding: This score is based on the potential to experience flooding at a given storage facility.

  No= 0

  Yes=1

- Seismic: This score is based on the potential seismicity a given storage facility.

Low = 1 *Med = 2* *High =3*

- Subsidence: This score consider is there is active subsidence at the facility.

No= 0 *Yes=1*

- Tsunami: This score considers the opportunity for a tsunami to impact the facility.

No= 0 *Yes=1*

- Landslide: This score considers if the facility and well site is situated where it could be impacted by landslides.

No= 0 *Yes=1*

2.5. Consequence Scoring Components

The consequence scoring components include the following factors as defined in the following subsections. The scoring component is shown in the shaded box within the section.

The scoring components are combined in the following equation:

$$\text{Consequence} = [\,(0.25 \times \text{Well Rate Factor}) + (\text{Well Operation Factor}) + \Sigma\,(\text{Proximity Factors})\,] - [\,5\text{x}\,(\,(0.5\ \text{Configuration}) + (\text{Valve Factor})\,)\,]$$

2.5.2. Well Rate Factor

- Rate Factor: This is based on the max current rate at the time of publishing the risk plan. Twenty-five percent of the rating factors into the consequence score to account for the reliability impact with the loss of a well.

2.5.3. Well Operation Factor

- Well Operation: The operational consequence of an event is also impacted that renders the well unusable has a greater implication on operations and use of the storage field. Withdrawal only wells carry an intermediate scoring as the unavailability of the well poses a risk to deliverability. Observation wells are assigned the lowest value in this category as unavailability would not impose a risk to operations.

Injection/Withdrawal (IW) = 3
Withdrawal only (wd only) = 2
Observation (obs) = 1

2.5.4. Proximity Factors

- Wind Direction Impact: This score looks at a well's surface location with respect to the nearest located structure and the predominant wind direction. This score is considered high such that a large release of gas could have severe impact with ignition on an adjacent facility. The score is low such that the predominant wind direction is away from adjacent structures.

High = 3
Low = 1

- Occupied Structure: This score is based on the well's surface location and its proximity to an occupied structure.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Offset Wells: This score is based on the well's surface location and its proximity to an adjacent wellhead.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Roads: This score is based on the well's surface location and its proximity to a road as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3
0-500 ft of Major Highway = 4

- Proximity to Railroads: This score is based on the well's surface location and its proximity to a railroad as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Major Airport: This score is based on the well's surface location and its proximity to a major airport as noted in the scoring.

>1000 ft = 1
500-1000 ft = 2
0-500 ft = 3

- Proximity to Population Centers: This score is based on the facility's location and the buffer rings indicated in the scoring.

> 1 Mile =3
1-2 Mile =2
2-5 Mile =1
>5 Mile = 0

- Proximity to Body of Water: This score is based on the facility's location and the buffer rings indicated in the scoring.

> 1 Mile =3
1-2 Mile =2
2-5 Mile =1
>5 Mile = 0

- Local Area/Land Use: This score is based on the facility's location and the surrounding area activity.

Urban = 4
Residential = 3
Crop farming (Irrigation/fertilizer / Plane) = 2
Cattle farming = 1

- Response to Well Incident: This score is based on proximity of employees to recognize and be able to respond in the event of a well emergency. Manned facilities have a higher likelihood that a response would be fairly soon after an event started or signs of an event could be recognized to minimize the impact.

Unmanned-2
Facility Manned-1

2.5.5. Valve Factor

This factor is used to reduce the consequence score by the mitigation employed by the presence and performance of a DHSV. The factor is computed in the following manner; each scoring component is listed and explained below.

$$\text{Valve Factor} = \left(\frac{\text{DHSV-Csg deployed}}{\text{DHSV-Csg Condition}} \right) + \left(\frac{\text{DHSV-Tbg deployed}}{\text{DHSV-Tbg Condition}} \right) + \left(\frac{1}{1 + \text{DHSV CL-cond}} \right)$$

- Well Configuration Factor: This score is used to reduce the consequence such that the dual barrier configuration would reduce the impact on the consequence.

  This score is factored by 50% in the final algorithm.

T&C Flow -1 T&P - 4

- DHSV Casing (Csg) Deployment: This score considers the presence of a DHSV on the casing side. Once wells are converted to tubing and packer, there is only a DHSV installed on the tubing side.

Yes -1 No - 0

- DHSV Tubing (Tbg) Deployment: This score considers the presence of a DHSV on the tubing side. Once wells are converted to tubing and packer, there is only a DHSV installed on the tubing side. Note: not all wells require a DHSV to be installed based on the critical well definition.

Yes -1 No - 0

- DHSV Casing (Csg) Condition: This score sums the number of level 4 leak by tests results a valve has received since installation.

# of Level 4 since installation

- DHSV Tubing (Tbg) Condition: This score sums the number of level 4 leak by tests results a valve has received since installation.

# of Level 4 since installation

- DHSV Control Line Condition: This score sums the number of level 4 leak by tests results the control line has received since installation.

# of Level 4 since installation

3. Pleasant Creek Construction Standard Implementation Plan

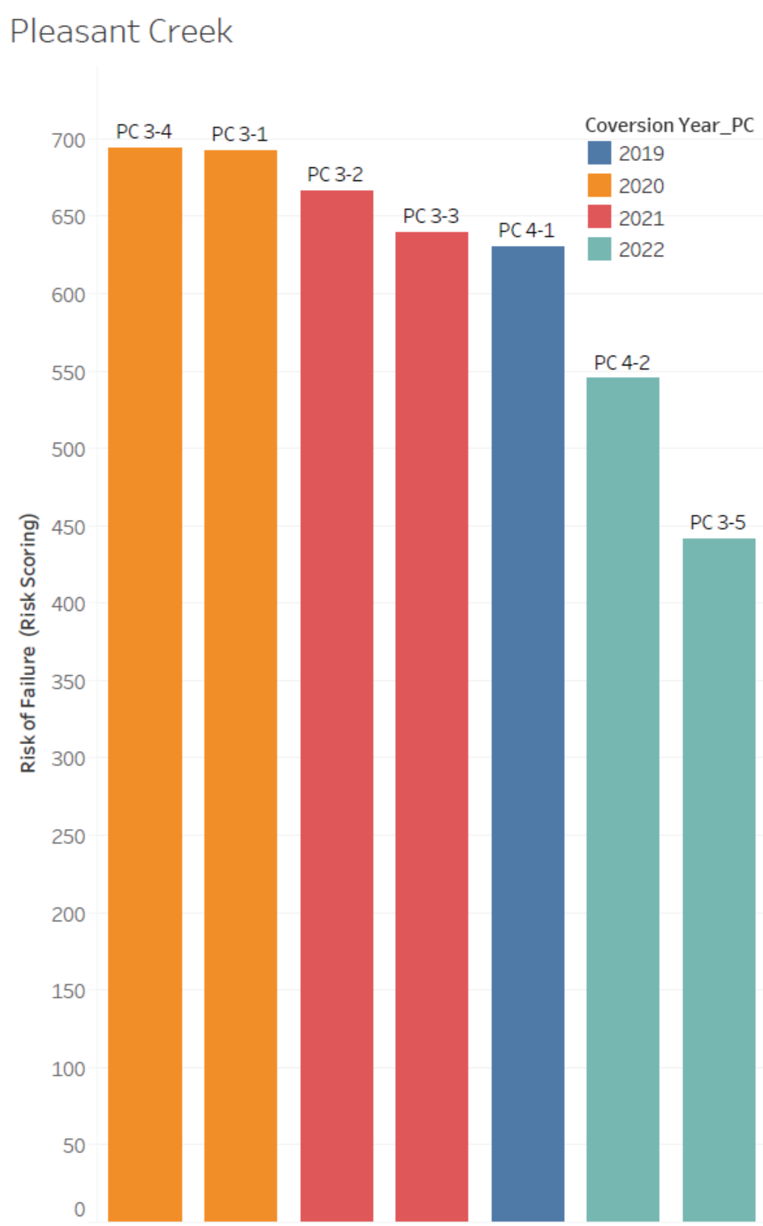
PG&E's wells located at Pleasant Creek are typically completed with open ended tubing and flow gas in both the tubing and casing annuli. In accordance with the construction standard in the DOGGR final regulations §1726.5, PG&E is phasing in the retrofits and/or permanent plug and abandonment as shown below in the schedule by year. Refer to the well specific schedule shown in Appendix B – Pleasant Creek Well Implementation and Assessment Schedule for the planned year of conversion. Additionally, Figure 3-1 shows the planned year of conversion and relative risk of a given well.

The well-by-well planned schedule is a living document and is based on the current data and inspection information known at the time this plan was published. The planned schedule is subject to change following the annual ranking update and where continuous evaluation activities necessitate advancing a well ahead of the planned date to address issues accordingly. Table 1 below shows the number of wells targeted by year to accomplish the conversion to tubing and packer configuration or plug and abandon by the end of 2025.

Table 1

Pleasant Creek 2019-2025 Well Construction Standard Implementation Plan			
Year	**Planned Number of Wells**	**% of Total Wells**	**Cumulative Count**
2019	1	14%	1
2020	2	29%	3
2021	2	29%	5
2022	2	29%	7

Figure 3-1: T&P Conversion shown by year and Risk Rank



4. Baseline and Reassessment Schedule & Methodology for Casing Inspection

PG&E performed a casing inspection in 2012 on 1 well (14% of field) at the time the well was completed; no subsequent or other casing inspections have been performed at Pleasant Creek to date. PG&E commenced the baseline casing inspection effort in 2013 at all fields and as the program advanced, additional logs and tests were grouped into the suite of testing to establish a baseline in 2016. The suite of testing is provided in the Risk and Integrity Management Plan in Appendix Z. The status of well assessments (from all field locations) can be grouped into three categories based on the time period when the assessment occurred:

1. **Pending Assessments:** Wells have not yet been inspected using advanced casing inspection tools. These wells have been inspected for baseline gas behind pipe using GRN tools. The wells have continued to be monitored annually via noise and temp (N&T) inspection. Additional daily and weekly monitoring activities (i.e. leak inspection and annular pressure monitoring) have been performed in alignment with the Risk and Integrity Management Plan Practices.

2. **Pre-2016 Assessments:** Wells were typically assessed using MFL tools for inspections, GRN tools during well work and also were monitored using the noise & temperature tools (N&T) annually. Additional daily and weekly monitoring activities (i.e. leak inspection and annular pressure monitoring) have been performed in alignment with the Risk and Integrity Management Plan Practices.

3. **2016-Current Assessments:** Wells were assessed using the full suite of inspections including MFL, CBL, N&T, GRN/RST, ultrasonic, caliper, and pressure testing. Additional daily and weekly monitoring activities (i.e. leak inspection and annular pressure monitoring) have been performed in alignment with the Risk and Integrity Management Plan Practices.

PG&E uses the guidance in Appendix C of the Risk and Integrity Management Plan to determine the reinspection frequency for a given well following a baseline or reinspection of casing condition. The typical casing frequency return period continues to fall into “12-15 year” re-assessment window based on limited metal loss (class 3 and below) and isolated condition. PG&E will be returning to the well that was previously assessed for conversion to tubing and packer ahead of follow up inspection and planned reassessment period.

PG&E plans to complete the remainder of the baseline inspections at Pleasant Creek during the well conversion to tubing and packer configuration period and may elect to plug and abandon wells. PG&E uses a methodology that is prioritized by risk and coupled with the ability to effectively and efficiently conduct the work, minimization of unnecessary equipment mobilization, and coordination with station projects (i.e. pipeline work, platform equipment maintenance/rebuilds) to reduce impact to deliverability and station outage. Figure 4-1 maps this approach and uses the results of the risk model, PG&E prioritizes the wells in the based on the risk score and looks at each of the following categories:

1. **Assessment Status of “Pending”**: wells pending assessment are targeted in the first group to be converted to tubing and packer configuration. During

that conversion activities, wells will be inspected using the full suite of inspection tools identified in Appendix Z.

2. **Assessment Status "Pre-2016"**: wells that are slated for re-inspection following their baseline metal thickness inspection will be targeted

3. **Assessment Status "2016- Current":** These wells have been evaluated using the full suite of logs in Appendix Z. Wells in this category typically have a re-assessment internal of 12-15years and PG&E will be returning to these wells to reconfigure them in a tubing and packer status ahead of the targeted re-assessment interval.

Using this approach, all wells at Pleasant Creek will have had an initial baseline casing condition inspection by the end of 2023. Additionally, PG&E plans to run a thru-tubing casing inspection log on wells that are pending assessment and not planned for work in 2020. This logging activity will continue every two years until the well has been assessed. This allows PG&E to identify if any of the wells pending assessment have any features that require remediation ahead of the planned schedule and can advance those wells accordingly. Further, for wells that have been previously assessed with a casing inspection, a thru-tubing surveillance logging program will commence in 2020 and cycle every two years until the well is converted to tubing and packer. The planned cadence for each group is also show in Figure 4-1.

Following a well's baseline inspection and/or conversion to tubing and packer, PG&E will identify the well's casing reassessment frequency per Appendix C of the Risk and Integrity Management Plan. PG&E plans to deploy a casing inspection surveillance program using thru-tubing technology to monitor for any changes in condition; note, this surveillance activity is in addition to the routine integrity monitoring practice (i.e. sand inspection, pressure monitoring, annual noise and temp survey).

Figure 4-2 illustrates the frequency of the thru-tubing inspection and pressure testing, per Appendix K of Risk and Integrity Management Plan. After the first two cycles of thru-tubing logging are performed, PG&E will space the 3rd logging activity halfway between the next planned reassessment. For example, a well scheduled on a 12-15 year reassessment interval will have a thru-tubing log run in year 2 and year 4 following conversion to T&P. The next thru-tubing log will be run in year 8, halfway between year 4 and year 12.

Refer to Appendix B for the planned schedule based on the methodology presented above.

Figure 4-1: Assessment in Year & T&P Conversion Risk Informed Methodology

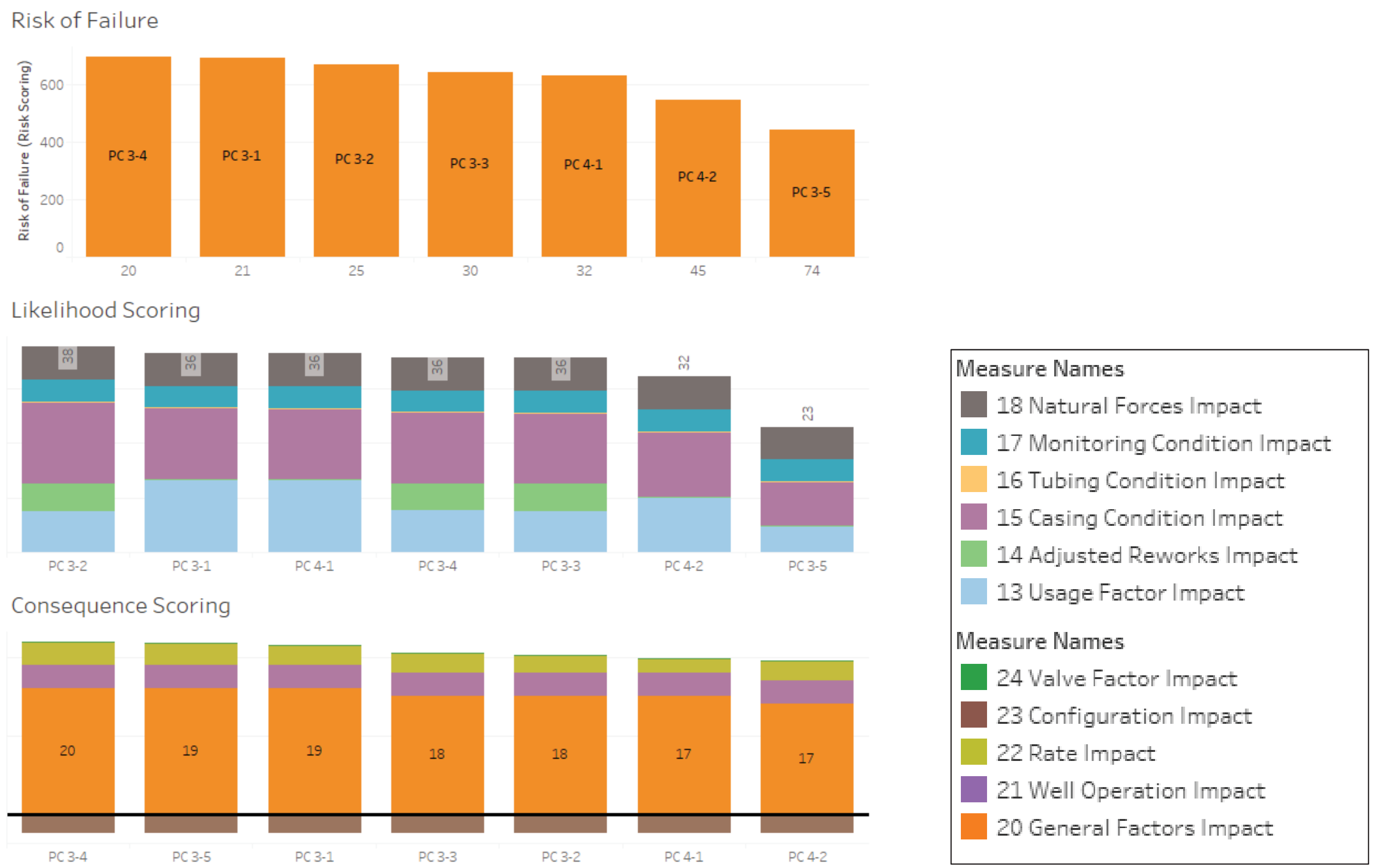
Year of Assessment	Assessment in Year & T&P Conversion						
	2019	2020	2021	2022	2023	2024	2025
Pending	2019 Planned Wells: Full Assessment with T&P Conversion						
Pending	N&T	2020 Full Assessment with T&P Conversion					
Pending	N&T Thru - Tubing	N&T	2021 Full Assessment with T&P Conversion				
Pending	N&T Thru - Tubing	N&T	N&T Thru - Tubing	2022 Full Assessment with T&P Conversion			
Pending	N&T Thru - Tubing	N&T	N&T Thru - Tubing	N&T	2023 Full Assessment with T&P Conversion		
2013 – mid 2016	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	2023 Full Assessment with T&P Conversion		
2013 – mid 2016	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T	2024 Full Assessment with T&P Conversion	
2016 – 2018	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T	2025 Full Assessment with T&P Conversion	
2016 – 2018	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T	N&T Thru- Tubing	Full Assessment with T&P Conversion

Figure 4-2: Assessments performed in Year Following T&P Conversion

Re-Assessment Interval	Assessment in Year Following T&P Conversion														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
3-5 Years	N&T	N&T	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval												
5-8 Years	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval										
8-12 Years	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T Pressure Testing	N&T	N&T	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval							
12-15 Years	N&T	N&T Thru - Tubing	N&T	N&T Thru- Tubing	N&T Pressure Testing	N&T	N&T	N&T Thru Tubing	N&T	N&T Pressure Testing	N&T	Full Assessment: Casing Inspection & Pressure Test Establish Re-Assessment Interval			

Appendix A – Pleasant Creek Relative Risk Well Evaluation

Figure A-1: Well by Well Risk of Failure Scoring – Pleasant Creek



**Note: The consequence scoring chart above shows a black line serving as the "zero" axis as the score components graphed below are mitigation components and reduce consequence.

Table 2 – Pleasant Creek Risk Evaluation (Input Data)

Well Name	API	Well Operation IW Wd only OBS	Well Operation IW = 3 Wd only = 2 OBS = 1	Spud Date	Completion Date	Years in Operation	Year of last Well Rework	Years since last Well Rework	# of Well Rework Performed	Measured Cement Bond Log TOC (feet)	Surface Csg (SC) Shoe, ft	Est. Distance to nearest offset well (feet)	Proximity to Roads (feet)	Proximity to Railroad (feet)	Proximity to Major Airport (feet)	Distance to Occupied Sturcture (HCA / Residence / Employee office-RE/Contrl Room building) (feet)	Proximity to Water (feet)
PC 3-4	11320194	I/W	3	10/15/1973	10/25/1973	45	2010	9	1	1320	527	272	4,955	5000	5000	2301	0
PC 3-1	11300063	I/W	3	11/27/1948	12/22/1948	70	1948	71	0	1720	524	962	3,053	5000	5000	986	0
PC 3-2	11320192	I/W	3	9/4/1973	9/20/1973	46	2011	8	1	1330	540	2098	2,094	5000	5000	1179	0
PC 3-3	11320193	I/W	3	9/22/1973	10/3/1973	46	2011	8	1	1335	493	951	3,996	5000	5000	1561	0
PC 4-1	11300064	I/W	3	6/12/1949	6/29/1949	70	1949	70	0	1932	498	957	7,180	5000	5000	4462	0
PC 4-2	11320195	I/W	3	10/4/1973	10/14/1973	46	1973	46	0	470	485	1293	5,860	5000	5000	3221	0
PC 3-5	11321279	I/W	3	4/20/2012	5/10/2012	7	2012	7	0	500	580	703	4,725	5000	5000	2111	0

Table 3 – Pleasant Creek Risk Evaluation (Likelihood Data)

Well Name	Well Operation IW = 3 (Likelihood) Wd only = 2 OBS = 1	Usage Factor	Adjusted # of Well Reworks	Original Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Inner String Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Production Casing Wall Thickness Unknown = 4 Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1	Source of Metal Loss on Production Casing Unknown = 4 Corrosion = 3 Mechanical = 2 None = 0	Potential Production Casing Mechanical Leak Path Uncovered Perforations = 5 Uncovered Stage collar = 4 Isolated (by cement or Inner String) Stage Collar = 3 Casing thread Leak = 2 None Identified/Not Applicable = 1	Dogleg Severity 0-5 %= 1 5-10% = 2 >10 % = 3	Inner String Installed Yes -2 No -1	Cement Bond Log TOC Full - 1 Inside SC - 2 Below SC - 3
PC 3-4	3	38	1	4	0	4	4	1	0	1	3
PC 3-1	3	67	0	4	0	4	4	1	0	1	3
PC 3-2	3	38	1	4	0	4	4	1	2	1	3
PC 3-3	3	38	1	4	0	4	4	1	0	1	3
PC 4-1	3	67	0	4	0	4	4	1	0	1	3
PC 4-2	3	51	0	4	0	4	4	1	0	1	2
PC 3-5	3	25	0	1	0	1	0	1	3	1	2

Table 4 – Pleasant Creek Risk Evaluation (Likelihood Data - Cont)

Well Name	**Tubing Wall Thickness** Class 3 or 4 = 3 Class 2 or general = 2 Isolated Class 1 or 2 = 1 Not Applicable = 0	**Potential Tubing Mechanical Leak Path** Tubing thread Leak = 2 None Identified/Not Applicable = 0	**Packer Condition** Known Leak=2 Sealing/Not Applicable = 0	**Annular Condition Monitoring Plan In Place** Yes - 3 No - 1	**Sand Production** # of Grade 3 or more since last rework	**Gas Composition** None = 0 CO_2 = 1 H_2S = 5	**Wellhead Tbg Head Condition - Known Leak** Yes - 2 No- 1	**Wellhead flange Condition - Known Leak** Yes - 2 No - 1	**Wellhead hydraulic Port leak** Yes -2 No- 1	**Known Hydrate Formation** No = 0 Yes = 1
PC 3-4	0	0	0	1	0	0	1	1	1	0
PC 3-1	0	0	0	1	0	0	1	1	1	0
PC 3-2	0	0	0	1	0	0	1	1	1	0
PC 3-3	0	0	0	1	0	0	1	1	1	0
PC 4-1	0	0	0	1	0	0	1	1	1	0
PC 4-2	0	0	0	1	0	0	1	1	1	0
PC 3-5	0	0	0	1	0	0	1	1	1	0

Table 5 – Pleasant Creek Risk Evaluation (Likelihood Data - Cont)

Well Name	**Known Hydrate Formation** No = 0 Yes = 1	**Well Security** Gated/fenced = 1 No = 2	**Wellhead Surface Damage Protection** **Full** Barricade (k-rail/bollard) =1, **Partial** Barricade (k-rail/bollard) = 2 **None** (Fenced only) = 3	**Natural Force Flooding** No= 0 Yes = 1	**Natural Force Seismic** Low PGA = 1 Med PGA = 2 High PGA =3	**Natural Force Subsidence** No= 0 Yes = 1	**Natural Force Tsunami** No= 0 Yes= 1	**Natural Force Lanslide** No= 0 Yes = 1
PC 3-4	0	1	3	0	2	0	0	0
PC 3-1	0	1	3	0	2	0	0	0
PC 3-2	0	1	3	0	2	0	0	0
PC 3-3	0	1	3	0	2	0	0	0
PC 4-1	0	1	3	0	2	0	0	0
PC 4-2	0	1	3	0	2	0	0	0
PC 3-5	0	1	3	0	2	0	0	0

Table 6 – Pleasant Creek Risk Evaluation (Consequence Data)

Well Name	Max Rate MMcf/d	Well Operation IW = 3 (Consequence) Wd only = 2 OBS = 1	Wind Direction Impact High - 3 Low - 1	Occupied Sturcture >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Proximity to Offset wells Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Proximity to Roads Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 0-500 ft of Major Highway = 4	Proximity to Railroad Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Proximity to Major Airport >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3	Population Centers > 1 Mile =3 1-2 Mile =2 2-5 Mile =1 >5 Mile = 0	Proximity to Body of Water Score >1000 ft = 1 500-1000 ft = 2 0-500 ft = 3 Water Well = 4, Navigable Waterway = 5	Local Area Activities/Land Use Urban = 4 Residential = 3 Crop farming (Irrigation/fertilizer / Plane) = 2 Cattle farming = 1	Response to Well Incident Unmanned-2 Facility Manned-1
PC 3-4	12	3	1	1	3	1	1	1	1	3	2	2
PC 3-1	10	3	1	2	2	1	1	1	1	3	2	2
PC 3-2	9	3	1	1	2	1	1	1	1	3	2	2
PC 3-3	10	3	1	1	2	1	1	1	1	3	2	2
PC 4-1	8	3	1	1	2	1	1	1	1	3	2	2
PC 4-2	10	3	1	1	1	1	1	1	1	3	2	2
PC 3-5	11	3	1	1	3	1	1	1	1	3	2	2

Table 7 – Pleasant Creek Risk Evaluation (Consequence Data - Cont)

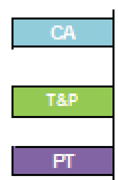
Well Name	Configuration T&C Flow -1 T&P - 4	DHSV Csg Deployment Yes -1 No- 0	DHSV Tbg Deployment Yes -1 No- 0	DHSV Tbg Condition # of Level 4 since installation	DHSV Csg Condition # of Level 4 since installation	DHSV Control Line Condition # of Level 4 since installation	Valve Factor	Likehood of Failure	Consequence of Failure	Risk of Failure (Risk Scoring)
PC 3-4	1	0	0	0	0	0	-	36	20	695
PC 3-1	1	0	0	0	0	0	-	36	19	692
PC 3-2	1	0	0	0	0	0	-	38	18	667
PC 3-3	1	0	0	0	0	0	-	36	18	640
PC 4-1	1	0	0	0	0	0	-	36	17	631
PC 4-2	1	0	0	0	0	0	-	32	17	546
PC 3-5	1	0	0	0	0	0	-	23	19	441

Appendix B - Pleasant Creek Well Construction Standard Implementation Plan and Assessment Schedule

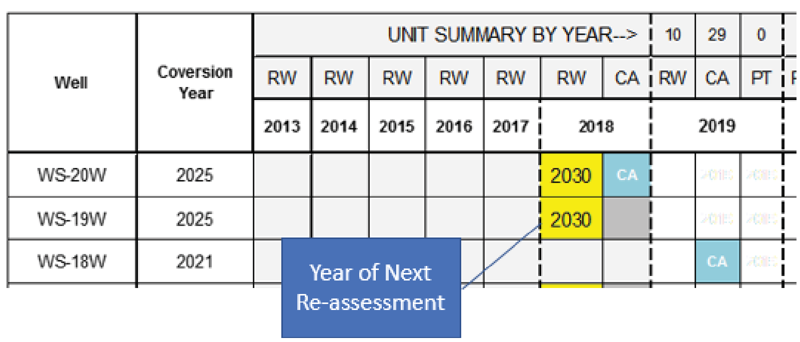
The following figures provide an overview of the applied methodology from Section 4 that includes conversion of PG&E's wells to tubing and packer and brings them into conformance with §1726.5 of the final regulations put forth by the Division. Additionally, the figures demonstrate the assessment methodology – both pre- and post-conversion to tubing and packer configuration. The plan shown below for each well is based on addressing wells with the highest risk identified in the risk analysis shown in Appendix A. The planned schedules in the following figures are based on current data in the risk model. As new monitoring data is received, the plan below is subject to change.

The charts below show three possible activities for each well by year from 2019 thru 2025:

1. Thru-tubing casing assessment (blue)
2. T&P conversion/full assessment (green)
3. 5-year re-assessment pressure test (purple)



Additionally, for wells previously assessed, the schedule is shaded with yellow and the planned reassessment year based on casing condition observed is noted.



For wells previously assessed, the decision to run a third thru-tubing log will rest with PG&E Reservoir Engineering following review of 2 sequential cycles thru-tubing logging results; note Example 1 shown below.

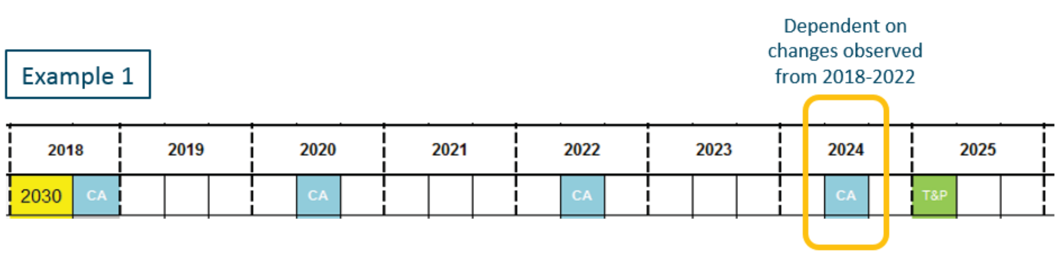


Figure B.1: Well Implementation and Assessment Schedule – Pleasant Creek

Well	Coversion Year	2012 RW	2013 RW	2014 RW	2015 RW	2016 RW	2017 RW	2018 RW	2018 CA	2019 RW	2019 CA	2019 PT	2020 RW	2020 CA	2020 PT	2021 RW	2021 CA	2021 PT	2022 RW	2022 CA	2022 PT	2023 RW	2023 CA	2023 PT	2024 RW	2024 CA	2024 PT	2025 RW	2025 CA	2025 PT
UNIT SUMMARY BY YEAR-->										1	3	0	2	1	0	2	1	0	2	2	0	0	2	0	0	4	0	0	2	2
PC 3-1	2020												T&P							CA						CA				PT
PC 3-2	2021										CA					T&P							CA						CA	
PC 3-3	2021										CA					T&P							CA						CA	
PC 3-4	2020												T&P							CA						CA				PT
PC 3-5	2022	2024												CA					T&P							CA				
PC 4-1	2019									P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A	P&A
PC 4-2	2022										CA						CA		T&P							CA				

Legend

RW Casing Assessment	Year of Relog
Thru-Tubing Casing Assessment	CA
Tubing & Packer Conversion Rework	T&P
Pressure Test (T&P)	PT
Reinspection Rework	RW
Plug & Abandon	P&A

California
Department of Conservation
Geologic Energy Management Division

Gavin Newsom, Governor
David Shabazian, Director
Uduak-Joe Ntuk, Supervisor

September 30, 2020

Pacific Gas and Electric Company
Attention: [redacted]
6121 Bollinger Canyon Road
San Ramon, CA 94583

SUBJECT: UNDERGROUND GAS STORAGE WELLS INTERIM CONDITIONAL TESTING SCHEDULE

Dear [redacted],

This letter responds to portions of the Risk Management Plan submitted by Pacific Gas & Electric (PG&E), relating to mechanical integrity testing required under section 1726.6 of the Geologic Energy Management Division's (CalGEM) Underground Gas Storage (UGS) regulations.[1] CalGEM and PG&E have exchanged correspondence and discussed PG&E's proposed testing schedule, including modified scheduling proposed since the onset of the COVID-19 pandemic. Although further discussion and revision will be needed before an approved testing schedule and plan can be finalized, PG&E has demonstrated to CalGEM's satisfaction that its wells can be safely used, as set forth below, during an interim testing period. This letter clarifies testing expectations and conditions that apply to use of the wells.

Well Safety Considerations

In considering this interim conditional testing schedule, CalGEM evaluated a range of safety indicators for each of PG&E's wells, including the following:

- Whether a well has been constructed with both primary and secondary mechanical well barriers
- Whether the well is monitored under a supervisory control and data acquisition (SCADA) system
- Whether continuous leak detection technology is employed at the wellhead
- Availability of detailed well construction documents

[1] CalGEM's Underground Gas Storage regulations are found in California Code of Regulations, title 14, sections 1726 through 1726.10.

- History of testing and inspection on the well

CalGEM's evaluation identified key safety indicators for each of PG&E's wells:

- PG&E employs SCADA systems for monitoring all of its wells;
    - The systems monitor pressure on both the tubing and all annuli
    - The systems run at all times and are monitored by personnel at all times
    - Personnel have the ability to manually shut in the systems
- All of the wells have leak detection technology employed at the wellhead daily;
- Detailed well casing diagrams have been provided to CalGEM for each of the wells; and
- Each of the wells has had successful noise and temperature logs run on them in the past year.

In addition, CalGEM evaluated other safety considerations specific to subsets of PG&E's wells as follows:

- Group 1 (23 wells)
    - Each of these wells has been constructed with both primary and secondary mechanical well barriers.
    - Pressure testing and direct casing thickness inspections have been completed on these wells.
- Group 2 (74 wells)
    - Most of these wells do not yet have dual-barrier construction.
    - Pressure testing has not yet been completed on these wells within the past 24 months, but some of these wells have been pressure tested within the last five years.
    - Each of these wells has had a casing thickness inspection using through-tubing magnetic thickness detector (MTD) technology.
- Group 3 (5 wells)
    - These wells do not yet have dual-barrier construction.
    - Neither pressure testing nor casing thickness inspections have been completed on these wells.
- Group 4 (6 wells)
    - Pleasant Creek - PG&E has ceased withdrawal and injection at the Pleasant Creek facility and has submitted a plan for decommissioning the field. CalGEM is currently evaluating that plan and compliance and safety considerations for wells at this facility will be addressed as part of an approved decommissioning plan.

Casing Thickness Inspection

Section 1726.6, subdivision (a)(2), of CalGEM's UGS regulations requires casing wall thickness inspection every 24 months for each well that penetrates the gas storage reservoir. The regulation allows for less frequent inspection of a well if the new frequency is supported by an established corrosion rate for the well that is derived from comparing results from two rounds of inspection.

As discussed above, PG&E has conducted casing thickness inspections on almost all of its wells. However, many of those casing thickness inspections were conducted using MTD, and CalGEM is still evaluating how effective MTD is for purposes of the UGS regulations. At this time, CalGEM is provisionally accepting MTD inspections for compliance with section 1726.6, subdivision (a)(2), conditioned upon additional inspections to validate the MTD as follows:

1) By April 1, 2021, PG&E will use magnetic flux or ultrasonic technology that is not run through tubing to inspect the casing of a select group of wells that were previously inspected using MTD. CalGEM will work with PG&E to determine which wells to inspect by April 1, 2021.
2) By October 1, 2022, PG&E will use magnetic flux or ultrasonic technology that is not run through tubing to inspect the casing of each of its wells that have not already had such an inspection (with the exception of the "Group 4" Pleasant Creek wells). This timeframe may be accelerated for some wells if the validation inspections completed by April 1, 2021, indicate that any integrity concerns were not effectively identified with MTD.
3) PG&E will provide CalGEM with results from these casing wall thickness inspections as soon as they are completed, notwithstanding that the UGS regulations generally allows 30 days for submission of test results.

Based on these comparisons and continuing analysis of the technology, CalGEM will determine whether and under what conditions MTD inspection will be a long-term option for compliance with the casing thickness inspection requirement. While CalGEM is accepting MTD inspection for compliance in the interim, be advised that it is not yet clear whether the MTD inspection results can be relied upon for establishing a corrosion rate for a well that would support a less frequent inspection schedule.

As of this date, PG&E appears to have some wells that have not had a casing thickness inspection in the past 24 months. If a well has not had a casing thickness inspection by October 1, 2020, then the well must not be used for injection or withdrawal of gas until inspection is complete and use is authorized by CalGEM.

Pressure Testing

Section 1726.6, subdivision (a)(3), of CalGEM's UGS regulations requires operators to periodically pressure test each well that penetrates the gas storage reservoir. The minimum frequency for pressure testing must be approved by CalGEM on a well-by-well basis based upon safety considerations for that well. If a well-specific pressure testing frequency is not approved for a well, then the regulations require pressure testing at least once every 24 months. PG&E's Risk Management Plan includes a proposed schedule for pressure testing each of its wells, but that proposed schedule is still under review by CalGEM and some amendments to that schedule may be required.

In the meantime, based on CalGEM's evaluation of well safety considerations, CalGEM is approving an interim minimum pressure testing frequency of 30 months for each of the wells. Under this interim testing schedule, one of three things must occur by April 1, 2021, for each of PG&E's wells penetrating a gas storage reservoir that has not had a pressure test since October 1, 2018:

1) CalGEM approves a longer minimum testing frequency;
2) PG&E completes pressure testing in accordance with section 1726.6; or
3) PG&E suspends use of the well for injection or withdrawal of gas.

If it is necessary to suspend use of a well due to lack of a completed pressure test, then PG&E would not be required to fill the inactive well, but steps may be required to seal the well against use.

Current Status of Wells

Included with this letter is a list of all PG&E's wells that penetrate a gas storage reservoir. That list indicates which of the wells currently have completed pressure tests and direct casing thickness inspections, and which wells will be under the interim pressure testing schedule and are pending verification of MTD casing inspections.

CalGEM anticipates working closely with you to coordinate on testing and inspection under the interim schedule. In accordance with this letter, there will be monthly management meetings between CalGEM and PG&E to review the criteria of this letter and evaluate well testing progress. Please continue to work with Emily Reader as the primary point of contact moving forward.

Thank you,

Uduak-Joe Ntuk
State Oil and Gas Supervisor

CC:
Emily Reader, Chief Deputy of Programs
Yuvaraj Sivalingam, Deputy Supervisor Policy and Administration

Field	Well Designation	API
Los Medanos Gas	Los Medanos 20-D	0401320297
Los Medanos Gas	Los Medanos 11-C	0401320128
McDonald Island Gas	Roberts Island 1	0407720524
McDonald Island Gas	Whiskey Slough 11-W	0407720265
McDonald Island Gas	Whiskey Slough 12-E	0407720255
McDonald Island Gas	Whiskey Slough 13-E	0407720256
McDonald Island Gas	Whiskey Slough 16-W	0407720231
McDonald Island Gas	Whiskey Slough 4-E	0407720178
McDonald Island Gas	Whiskey Slough 5-E	0407720179
McDonald Island Gas	Whiskey Slough 7-E	0407720187
McDonald Island Gas	Zuckerman-Henning 1	0407720010
McDonald Island Gas	Whisky Slough 9-E	0407720189
McDonald Island Gas	McDonald Island Farms 12	0407700087
McDonald Island Gas	Turner Cut 10-S	0407720251
Los Medanos Gas	Los Medanos 15-C	0401320121
McDonald Island Gas	Turner Cut 2-S	0407720219
McDonald Island Gas	Turner Cut 7-S	0407720206
McDonald Island Gas	Weyl-Zuckerman 1	0407700091
McDonald Island Gas	Whiskey Slough 11-E	0407720253
McDonald Island Gas	Whiskey Slough 14-E	0407720257
McDonald Island Gas	Whiskey Slough 6-E	0407720185
McDonald Island Gas	Whiskey Slough 7-W	0407720193
McDonald Island Gas	Whiskey Slough 8-E	0407720188

Field	Well Designation	API
McDonald Island Gas	McDonald Island Farms 11	0407700086
McDonald Island Gas	Turner Cut 12-N	0407720230
McDonald Island Gas	Whiskey Slough 1A-E	0407720536
McDonald Island Gas	McDonald Island Farms 10	0407700085
McDonald Island Gas	Turner Cut 16-S	0407720243
McDonald Island Gas	Turner Cut 6-S	0407720205
McDonald Island Gas	Turner Cut 5-S	0407720204
McDonald Island Gas	Turner Cut 15-N	0407720239
McDonald Island Gas	Turner Cut 10-N	0407720228
McDonald Island Gas	Turner Cut 17-S	0407720258
McDonald Island Gas	Turner Cut 1-S	0407720218
McDonald Island Gas	Turner Cut 3-N	0407720201
McDonald Island Gas	Turner Cut 4-N	0407720202
McDonald Island Gas	Turner Cut 7-N	0407720225
McDonald Island Gas	Turner Cut 9-N	0407720227
McDonald Island Gas	Whiskey Slough 12-W	0407720264
McDonald Island Gas	Whiskey Slough 13-W	0407720241
McDonald Island Gas	Whiskey Slough 1A-W	0407720544
McDonald Island Gas	Whiskey Slough 2-E	0407720169
McDonald Island Gas	Whiskey Slough 8-W	0407720194
Los Medanos Gas	Los Medanos 12-C	0401320307
McDonald Island Gas	McDonald Island Farms 9	0407700084
McDonald Island Gas	Turner Cut 1A-S	0407720551
McDonald Island Gas	Turner Cut 2-N	0407720199
McDonald Island Gas	Whiskey Slough 19-W	0407720467
McDonald Island Gas	Whiskey Slough 20-W	0407720535
McDonald Island Gas	Whiskey Slough 3-E	0407720173
McDonald Island Gas	Whiskey Slough 6-W	0407720192
McDonald Island Gas	Whisky Slough 17-W	0407720166
McDonald Island Gas	Turner Cut 12-S	0407720248
Los Medanos Gas	Los Medanos 17-D	0401320136
Los Medanos Gas	Los Medanos 10-C	0401320131
Los Medanos Gas	Los Medanos 16-D	0401320133
McDonald Island Gas	McDonald Island Farms 13	0407700088
McDonald Island Gas	Turner Cut 11-N	0407720229
McDonald Island Gas	Turner Cut 3-S	0407720216
McDonald Island Gas	Turner Cut 4-S	0407720203
McDonald Island Gas	Turner Cut 8-S	0407720533
Los Medanos Gas	Los Medanos 19-D	0401320295
McDonald Island Gas	Lil Mac 1	0407720609
Los Medanos Gas	Los Medanos 3-A	0401320115
Los Medanos Gas	Los Medanos 7-C	0401320130
McDonald Island Gas	McDonald Island Farms 14	0407720441
McDonald Island Gas	McDonald Island Farms 15	0407720444
McDonald Island Gas	McDonald Island Farms 5A	0407720552
McDonald Island Gas	Turner Cut 16-N	0407720240
McDonald Island Gas	Turner Cut 5-N	0407720207
McDonald Island Gas	Turner Cut 6-N	0407720208
McDonald Island Gas	Whiskey Slough 10-E	0407720190
McDonald Island Gas	Whiskey Slough 18-W	0407720465
McDonald Island Gas	Whiskey Slough 2-W	0407720212
McDonald Island Gas	Whiskey Slough 3-W	0407720213
McDonald Island Gas	Whiskey Slough 5-W	0407720211
Los Medanos Gas	Los Medanos 5-B	0401320144
Los Medanos Gas	Los Medanos 6-B	0401320140
Los Medanos Gas	Los Medanos 9-C	0401320123
McDonald Island Gas	McDonald Island Farms 4	0407700080
McDonald Island Gas	Turner Cut 11-S	0407720250
McDonald Island Gas	Turner Cut 13-N	0407720234
McDonald Island Gas	Turner Cut 13-S	0407720247
McDonald Island Gas	Turner Cut 14-S	0407720244
McDonald Island Gas	Turner Cut 15-S	0407720245
McDonald Island Gas	Turner Cut 17N	0407720548
McDonald Island Gas	Turner Cut 1-N	0407720196
McDonald Island Gas	Turner Cut 9-S	0407720252
McDonald Island Gas	Whiskey Slough 10-W	0407720534
McDonald Island Gas	Whisky Slough 14-W	0407720238
Los Medanos Gas	Los Medanos 13-C	0401320299
Los Medanos Gas	Los Medanos 14-C	0401320298
Los Medanos Gas	Los Medanos 21-D	0401320308
McDonald Island Gas	Turner Cut 8-N	0407720226
McDonald Island Gas	Whiskey Slough 1-W	0407720215
Los Medanos Gas	Los Medanos 2-A	0401320138
McDonald Island Gas	Whiskey Slough 1-E	0407720168

Field	Well Designation	API
McDonald Island Gas	McDonald Island Farms 6	0407700082
McDonald Island Gas	Whiskey Slough 15-W	0407720233
McDonald Island Gas	Whiskey Slough 4-W	0407720214
McDonald Island Gas	Whiskey Slough 9-W	0407720195
McDonald Island Gas	McDonald Island Farms 7	0407700083

Field	Well Designation	API
Pleasant Creek Gas	Pleasant Creek Unit 3 1	0411300063
Pleasant Creek Gas	Pleasant Creek Unit 3 2	0411320192
Pleasant Creek Gas	Pleasant Creek Unit 3 3	0411320193
Pleasant Creek Gas	Pleasant Creek Unit 3 4	0411320194
Pleasant Creek Gas	Pleasant Creek Unit 3 5	0411321279
Pleasant Creek Gas	Pleasant Creek Unit 4 2	0411320195

Lucy Redmond
Director, Reservoir Engineering
Pacific Gas and Electric Company
6121 Bollinger Canyon Road
San Ramon, CA 94583

October 9, 2020 **By Email**

Mr. Uduak-Joe Ntuk
State Oil & Gas Supervisor
Department of Conservation
California Geologic Energy Management Division

Re: Final CalGEM UGS Interim Testing Schedule Letter – PGE 20200930

Dear Mr. Ntuk,

Pacific Gas and Electric Company (PG&E) has reviewed the interim provisions set forth in the California Geologic Energy Management Division's (CalGEM or Division) September 30, 2020 letter (the letter), and appreciates the engagement from the Division and other agencies[1] to find a solution that satisfies the regulatory intent and provides sufficient storage service to support California's natural gas market reliability jointly with the ISPs[2] and IOUs. However, PG&E is obligated to alert the Division to outstanding near-term and long-term gas market reliability issues that arise from the additional requirements outlined in the letter. These issues are the result of physical restrictions PG&E detailed in prior correspondence to the Division and during the rulemaking process. These current issues arise out of concern with meeting the letter timelines, which in some cases are contrary to existing regulations, and the additional ambiguity introduced by the absence of CalGEM's review and approval of key areas contained within operators' Risk and Integrity Management Plans (RMP).

As submitted to the Division for approval on March 29, 2019, PG&E's RMP proposed a balanced pace of implementation of retrofitting existing wells to tubing and packer (thus reducing each well's deliverability) consistent with the seven-year schedule outlined in the regulations[3], and coupled pressure testing and direct casing inspection with this activity. This approach is both effective in managing safety, risk and the state's energy system reliability, and efficient in execution and meeting the requirements of the regulations.

New April 1, 2021 Deadline Poses 2020-2021 Winter Reliability Impacts
In the letter, the Division indicated a yet-to-be-determined population of wells will need to be inspected by April 1, 2021, using either magnetic flux (MFL) or ultrasonic (USIT) technologies to inspect the wells' production casing barriers. As previously stated, to perform inspections that require a rig, it can take anywhere from 14 to 40 plus days depending on the subject well. Intricate planning is needed to facilitate the safe execution of the work at PG&E's facilities due to physical

[1] California Public Utilities Commission, California Energy Commission, Pipeline and Hazardous Materials Safety Administration, National Labs, and California Natural Resources Agency.
[2] PG&E owns a 25% interest in Gill Ranch Storage, LLC and relies on deliverability from all ISPs under the Natural Gas Storage Strategy (NGSS) per CPUC Decision (D.) 19-09-025
[3]California Code of Regulations, Title 14, Section 1726.3(d)(1).

station layout constraints. At the McDonald Island station platforms (Whiskey Slough and Turner Cut), a majority of the wells are concentrated along each side. For context, 70 of the 85 wells at McDonald Island line the stations at a 25-foot-on-center spacing. In order to meet an April 1, 2021 deadline, the rig mobilization would need to start well ahead of that date, impacting the winter withdrawal season.

With the seasonal and cyclical nature of the storage field, PG&E initiates rework activities and subsequent well outages typically beginning in March of each year to minimize these deliverability constraints. Thus, the number of wells needed to comply with this April 1, 2021 deadline has to contemplate feasibility of work execution and the resulting impact to deliverability. PG&E would like to raise for the Division's consideration that any increase to the number of wells needed to comply by April 1, 2021, outside of those already planned for completion by that date, will impact the winter withdrawal season.

Months of preparation are required for well inspection work, including securing qualified vendors, material sourcing, project funding and production of engineering programs, as well as the time required to submit a Notice of Intent (NOI) with CalGEM and receive a permit. PG&E already has an aggressive plan scheduled for 2021 and these projects are already in development. Interruptions to this schedule, unless necessary for safety reasons, will undermine the significant efforts and ratepayer money already expended to prepare for 2021 well work and compromise PG&E's ability to balance other safety-related work at the stations and on the pipeline system.

Any Deadlines Need to Consider Compounding of Re-inspections Pending Approval of Operator's Risk Management Plans

The letter requires that all wells not having a direct casing inspection but that have been inspected via thru-tubing (i.e., MTD log) must have an MFL or USIT inspection completed by October 1, 2022. PG&E has 40 wells in this category— 30 of which are at McDonald Island not counting wells inspected with MFL and USIT prior to the effective date of the final regulations. PG&E forecasts a compounding impact of the number of additional wells that would require re-inspection within this same period on a 24-month cadence if thru-tubing inspections are not accepted and if an alternate pressure testing schedule is not accepted. To further illustrate this, the 10 wells that PG&E completed[4] in 2019 would also potentially be subject to direct casing re-inspection by October 1, 2021, and the 15 wells completed in 2020 would similarly be subject to direct casing re-inspection before October 1, 2022, adding to the number of wells now required under the letter. This new letter requirement coupled with the outstanding approval of a risk-based reinspection frequency and use of the thru-tubing presented in PG&E's RMP heavily impacts Winter 2020-2021 storage reliability as well as the injection season, further reducing the deliverability in future storage cycles. Without the RMP acceptance, PG&E's ability to plan and effectively execute with footprint issues and mitigate and forecast capacity shortfalls is severely hindered.

---

[4] The well counts reflected as completed in 2019 and 2020 include only wells returned to service with dual barrier, T&P construction, and exclude the wells that were plugged and abandoned. The wells completed in 2019 are planned for MTD inspection in 2021 per PG&E's RMP.

April 1, 2021 Pressure Testing Requirement Challenges Winter Reliability
PG&E escalated review of its RMP after waiting approximately 16 months for the Division to act. Rather than review and approve or recommend direct modifications to the RMP as contemplated in the regulations, the letter now subjects nearly 80% of PG&E's wells to an April 1, 2021 deadline to perform pressure testing unless the Division approves an alternate schedule, such as that presented in PG&E's RMP. Six months of lead time to plan, contract for, and execute pressure tests on these wells is woefully inadequate. PG&E sought urgent action by the Division and escalated the issue for this reason. Resolution of this conflict must be of the highest priority for the Division to avoid a loss of capacity and related impact on winter reliability. The pressure testing provision still has significant impacts on reliability through the seven-year period until all the wells have been phased in with tubing and packer as described in the RMP, as proposed in PG&E's RMP that was developed intentionally to balance risk and reliability.

Direct Casing Inspections and Pressure Testing Necessitate CalGEM Permits - Accelerating Deliverability Reductions with Dual-barrier Well Construction Standard
As stated above, to perform the well inspections, PG&E must file a notice of intent (NOI) with the Division to receive a permit prior to conducting any downhole work that requires removal of the wellhead. It is unlikely PG&E would receive a permit to perform this work unless the final construction of the well conforms to current construction requirements of dual barrier (tubing and packer) upon completion. This will prematurely reduce production rates ahead of the regulatory timeline, as well as PG&E's ability to permit and drill additional wells to offset any reliability shortfalls through 2025. From a practical perspective, this directly conflicts with the regulations that allow for a 7-year schedule to complete the conversion work to dual barrier.

COVID-19 Impacts Are Not Slowing Work
PG&E wishes to emphasize that all of this remains subject to the ongoing impacts from COVID-19. While PG&E accomplished additional conversion work that we pulled forward to meet the October 1, 2021 construction deadlines, we continue to see vendor cases where crews need to be isolated due to positive COVID-19 tests of their employees.

PG&E also would like to clarify the statement in the Division's letter that COVID-19 prompted a request for a modified schedule. This statement is not correct, as PG&E has been executing to the schedule contained in its RMP submitted to the Division in March 2019 following the Division's verbal guidance to do so. The RMP included conducting direct casing inspections and pressure testing concurrent to the well conversions over the 7-year period, and utilizing thru-tubing logging (i.e. MTD) to inspect well casing conditions every 24 months leading up to and following a well's direct casing inspection, pressure test, and conversion to tubing and packer. To clarify, PG&E alerted the Division of potential concerns with meeting the annual construction compliance deadline of October 1, 2020 due to COVID-19 impacts that shut the rigs down during appropriate quarantine periods and requested written concurrence to continue following the RMP as previously guided by the Division. PG&E ultimately met its October 1, 2020 deadlines per its RMP despite the COVID-19 challenges.

Monthly Meetings

PG&E is pleased with the opportunity to meet regularly again with the Division; PG&E and the Division previously held quarterly meetings from 2016 through early 2020. Following receipt of the letter, PG&E requested to meet with the Division as soon as possible to discuss these continuing issues and is looking forward to the scheduled session on Monday, October 12. PG&E anticipates engagement of critical CalGEM management personnel to enable a prompt resolution to these noted issues. PG&E also suggests the Division set up a workshop with California storage operators and stakeholder agencies to continue to review the impact the current requirements, both the final regulations and those requirements introduced in the letter, will have on the state's gas system reliability.

We look forward to a productive discussion to find solutions to these issues. Should you or anyone with CalGEM have any questions, please contact me at 925-453-9276.

Sincerely,

Lucy M Redmond

Lucy Redmond
Director, Reservoir Engineering
Pacific Gas and Electric Company

Cc:

David Shabazian, Director, Department of Conservation
Alan Walker, Supervising Petroleum Engineer, CalGEM
Charlene Wardlow, District Deputy, CalGEM
Emily Reader, Chief Deputy of Programs, CalGEM
Yuvaraj Sivalingam, Deputy Supervisor, CalGEM
Justin Turner, Assistant Chief Counsel, CalGEM
Caryn Craig, Senior Attorney, CalGEM
Christine Cowsert, Vice President, PG&E
[redacted], Director, PG&E
[redacted], Director, PG&E
[redacted], Senior Director, PG&E
[redacted], Chief, PG&E
[redacted], Senior Counsel, PG&E

California
Department of Conservation
Geologic Energy Management Division

Gavin Newsom, Governor
David Shabazian, Director

December 1, 2020

TRANSMITTED VIA ELECTRONIC MAIL
Pacific Gas and Electric Company
Attention: [redacted]
6121 Bollinger Canyon Road
San Ramon, CA 94583

FOLLOW UP ON UNDERGROUND GAS STORAGE WELLS INTERIM CONDITIONAL TESTING SCHEDULE

Dear [redacted]:

This letter follows up on the Geologic Energy Management Division (CalGEM) letter dated September 30, 2020, and the meeting held on November 16, 2020, regarding the development of an acceptable schedule for Pacific Gas and Electric Company (PG&E) to complete the mechanical integrity testing (MIT) required under section 1726.6 of CalGEM's Underground Gas Storage (UGS) regulations.[1]

PG&E has proposed to couple casing thickness and pressure testing with the well construction work under its seven-year work plan required by section 1726.5. As set forth in CalGEM's September 30, 2020 letter, section 1726.6, subdivision (a)(2) requires casing wall thickness inspection every 24 months for each well that penetrates the gas storage reservoir unless a less frequent inspection schedule is supported by an established corrosion rate derived from comparing results from two rounds of inspection. Section 1726.6, subdivision (a)(3) requires pressure testing of each well that penetrates the gas storage reservoir and unless a well-specific pressure testing frequency is approved for a well based on well-specific safety considerations, testing must be completed at least once every 24 months. To date, PG&E has not demonstrated to CalGEM's satisfaction that a testing frequency for up to seven years is appropriate for its wells, and thus PG&E's request to align testing with its well construction work plan is denied.

PG&E incorrectly states that CalGEM will not permit completion of MIT on a well not in compliance with the dual barrier well construction requirements of section 1726.5 unless the nonconforming well is converted to meet section 1726.5 standards, regardless of when the well is scheduled on PG&E's seven-year well construction work plan. These requirements are independent obligations. PG&E may choose to accelerate and align well construction work with MIT where possible and consistent with each regulatory scheme, but is not required to do so. A well that fails MIT, however, may not be used for

[1] CalGEM's Underground Gas Storage regulations are found in California Code of Regulations, title 14, sections 1726 through 1726.10. All references to code sections herein are to CalGEM's UGS regulations.

injection or withdrawal until the well is remediated and approved for use, or plugged and abandoned.

CalGEM will continue to work with PG&E to establish, no later than April 1, 2021, acceptable well-specific, risk-based testing timeframes. The following conditions apply to ensure that the schedule is timely developed, submitted, evaluated and approved:

- By January 15, 2021, PG&E shall submit a revised preliminary MIT schedule for each well that has not had since October 1, 2018, a casing thickness inspection and successful pressure test in accordance with the UGS MIT regulations.
- PG&E shall continue to meet with CalGEM staff biweekly to further discuss testing expectations and PG&E's progress on schedule development.

Any well that is not tested or scheduled for testing in accordance with the expectations outlined by CalGEM, shall not be used for injection or withdrawal of gas after April 1, 2021. If the above conditions are not met, the April 1, 2021 deadline may be accelerated.

CalGEM anticipates continuing to work closely with you to develop and approve an appropriate mechanical integrity testing schedule, and to coordinate meetings and other work necessary for schedule development and review. Please continue to work with Emily Reader as your primary point of contact.

Sincerely,

Uduak-Joe Ntuk
State Oil and Gas Supervisor

CC: Emily Reader, Programs II Manager
Yuvaraj Sivalingam, Deputy Supervisor Policy and Administration

Lucy Redmond
Director, Reservoir Engineering
Pacific Gas and Electric Company
6121 Bollinger Canyon Road
San Ramon, CA 94583

January 15, 2021 **By Email**

Mr. Uduak-Joe Ntuk
State Oil & Gas Supervisor
Department of Conservation
California Geologic Energy Management Division

Re: Follow up on Underground Gas Storage Wells Interim Conditional Testing Schedule

Dear Mr. Ntuk,

This letter accompanies Pacific Gas and Electric Company's (PG&E) submittal of a revised preliminary mechanical integrity testing (MIT) schedule for wells at its McDonald Island and Los Medanos underground gas storage facilities, as requested by the California Geologic Energy Management Division (CalGEM or Division) in its letter of December 1, 2020. PG&E appreciates the engagement from the Division and other agencies[1] to establish a testing plan that satisfies the regulatory intent and continues to provide sufficient storage service, jointly with the independent storage providers (ISPs[2]), to support the reliability of California's natural gas market.

The revised plan included with this letter for the Division's review and approval continues to balance the pace of both direct casing thickness inspections and pressure testing. This approach will ensure safe execution at the facilities, with a physical footprint that enables PG&E to maintain the redundancy it is mandated to provide to balance inherent system risks. Further, it ensures PG&E can perform the needed safety and compliance inspections on the station and system pipelines that transport natural gas from the underground storage facilities to the communities we serve.

Key Elements of Revised Plan

In its December 1, 2020 letter, the Division indicated that the 7-year plan PG&E presented for review and approval in March 2019, which included coordinated inspection, pressure testing and conversion work over that time period, was unsatisfactory, and the plan was denied. Based on continued dialogue and meetings with the Division since December 1, PG&E has updated the plan for the Division's review and approval and has accelerated the integrity inspection work significantly. The revised implementation plan, appended to this letter, continues to prioritize the work execution schedule to reduce risk. The revised plan completes direct inspections, pressure testing, and conversion to dual barrier by 2024, approximately 12 months ahead of PG&E's proposed March 2019 plan.

[1] California Public Utilities Commission, California Energy Commission, Pipeline and Hazardous Materials Safety Administration, National Labs, and California Natural Resources Agency.
[2] PG&E owns a 25% interest in Gill Ranch Storage, LLC and relies on deliverability from all ISPs under the Natural Gas Storage Strategy (NGSS) per CPUC Decision (D.) 19-09-025.

Key elements of the well specific plan are expanded upon below and highlight integrity inspection milestones:

- **Casing Inspection with MFL and UST completed by December 31, 2023:** All active wells will have received a direct casing inspection *with both* the MFL and UST technologies, as well as a multi-finger caliper tool. This approach of employing multiple technologies exceeds the Division's regulatory requirement and is an integral part of PG&E's integrity management program.

- **Pressure Testing per 1726.6(a)(3) completed by December 31, 2024:** All active wells will have had a pressure test per Regulation 1726.6(a)(3). Many of PG&E's wells that were already part of PG&E's integrity inspection program, that predated both federal and state underground storage regulations, had already been tested between 2016 and 2018 per Order No. 1109, the Aliso Canyon Inspection Criteria. In fact, 15 of the 20 wells planned to be inspected in 2024 were certified by the Division to have passed the testing regime and were found to have mechanical integrity. PG&E will be pressure testing these wells again per the revised plan.

- **Retrofitting of wells to dual barrier complete by October 1, 2024:** All active wells will meet the dual barrier construction requirements. PG&E recognizes the Division's letter has defined the construction standard as a separate requirement from the inspection and testing. However, to efficiently execute this work on behalf of PG&E's ratepayers, PG&E strongly recommends continuing coordinating this work together and as an additional means to reduce the inherent risk intervention activity.

Reinspection and Continued Surveillance following Preliminary Inspection & Testing
Following the testing outlined above, the wells will continue to be monitored and re-inspected per the following:

- **Reinspection with Direct Tools**: Given the risks of damage to well facilities associated with inspection activities, PG&E proposes that the reinspection of the well production casings via direct methods that require a rig mobilization, such as MFL or UST, follow a risk-informed and condition-based framework included in PG&E's Appendix C.

- **Reinspection with Thru-tubing Tools:** All wells will continue to be inspected at least every 24 months ahead of and following conversion to tubing and packer configuration. This technology allows PG&E to monitor for any change of condition that necessitates acceleration of condition-based inspection.

- **Pressure Testing:** PG&E continues to propose periodic pressure testing of the tubing-casing annulus following conversion to tubing and packer (i.e. where a rig is not required to disassemble the well to complete this testing) follow the 5-year reassessment schedule as presented in PG&E's RMP in Appendix K.

- **Surveillance and Monitoring:** The wells will be inspected annually (during the typical inspection season at peak inventory levels) with noise and temperature surveys. Continuous annular monitoring and daily leak survey are in place and ensure any emergent conditions are addressed appropriately to prevent escalation. Annual inventory verification additionally confirms overall reservoir and well integrity.

PG&E's well-specific plan is based upon the information it has at the time of submission to the Division for approval and is subject to change should new information require adjustment. PG&E will confer with the Division on any significant required changes.

COVID-19 Impacts
PG&E re-emphasizes that successful execution of this plan remains subject to the ongoing impacts from COVID-19. PG&E continues to see employee and vendor cases and is monitoring to ensure appropriate stability to commence work. Further, PG&E has strict protocols to reduce spread during rig operations that could result in delays. As in 2020, PG&E will continue to keep the Division informed on progress.

Continued Dialogue
PG&E would like to recognize the Division's engagement over the last several months and appreciates the dialogue it has enabled. During more recent monthly meetings with the Division's underground storage program personnel, PG&E has presented and discussed at length the compounding impact to reliability resulting from the default UGS compliance timelines, as well as the safety risks presented by implementing an inspection schedule at the default compliance frequency. For Northern California storage facilities, there are additional considerations that have factored into these discussions. Seasonal timeframes for the northern system translate into limited windows in which work can be safely executed at scale. During the winter season, capacity is needed to meet peak winter demand days and conversely, in the non-peak-withdrawal months, adequate injection capacity needs to be maintained to refill the field to meet the next anticipated winter peaks.

Further, PG&E discussed with the Division the intricacies of its storage facility layouts and the overlaying impact of adjacent well outages, outages from compressor station and pipeline compliance activities, and emergent work on the system that make it impossible to execute the default 24-month inspection cycle and still provide reliable service.

Another concern PG&E has voiced consistently and reiterates here is that well interventions for the purpose of complying with default regulations, without a risk-based need to complete those interventions, need to be balanced with ensuring safety and well integrity in light of the risks of repeated interventions and overall system risks. In PG&E's case, data collected in prior inspections demonstrates the risks of mechanical damage due to repeated inspection of wells exceeds the risks of potential for corrosion due to the geologic environment in which PG&E's wells are located. A 24-month reinspection frequency with direct tools will not reveal notable changes to casing condition, presents a greater safety risk to the crews and personnel working within the immediate area, and paradoxically increases the likelihood of a well event.

Within the industry and the scientific communities that study risk[3], it is recognized that well intervention risk is a leading risk to wells, more so when added equipment installed downhole requires removal. PG&E has shared with the Division that metal loss observed at PG&E's storage facilities is predominantly a result of downhole well work, such as that required under the regulations. This type of risk was evidenced in recent months during downhole well work at a storage facility PG&E partially owns but does not operate. While the potential event was de-escalated to prevent a loss-of-containment event, it resulted in damage to the production casing that would not have occurred absent a requirement for intervention. Finally, the regulation provides operators the ability to request and the Supervisor the authority to approve inspection cadences that vary from the 24-month default requirement, based upon an appropriate risk-based showing by the operator.

PG&E recommends the Division schedule a workshop with California storage operators and stakeholder agencies to continue to review the impact the current default regulations and those requirements introduced in recent letters to California UGS operators will have on the state's gas system reliability. PG&E also urges the Division to consider utilizing any currently open rulemakings, such as its public health rulemaking that is underway, to amend its UGS regulations to avoid the unintentional consequences of prescriptive policies that do not consider the inspection limitations of each storage facility's design and operating environment.

We look forward to reviewing this plan with the Division and having a productive discussion to find solutions to these critical issues. To enable PG&E to implement its revised plan effectively, PG&E respectfully requests approval by March 1, 2021. Should you have any questions, please contact me at 925-453-9276.

Sincerely,

Lucy M Redmond

Lucy Redmond
Director, Reservoir Engineering
Pacific Gas and Electric Company

---

[3] Stephens, M., et al. "Risk Assessment and Treatment of Wells," *C-FER Technologies prepared for Pipeline and Hazard Materials Safety Administration (PHMSA), September 2020.*
Winecki, S., et al. "Reliability of Subsurface Safety Valves (SSSVs)- Cost/Benefit Analysis for SSSVs in Underground Gas Storage Wells," *Battelle Memorial Institute, Sandia National Laboratory, & Nova Northstar LLC, prepared for Pipeline and Hazard Materials Safety Administration (PHMSA), October 2020.*
Winecki, S., et al. "Tubing and Packer Life-Cycle Analysis for Underground Gas Storage Applications," *Battelle Memorial Institute, Sandia National Laboratory, & Nova Northstar LLC, prepared for Pipeline and Hazard Materials Safety Administration (PHMSA), October 2020.*

Cc:

Emily Reader, Programs II Manager, CalGEM
Charlene Wardlow, District Deputy, CalGEM
Yuvaraj Sivalingam, Deputy Supervisor, CalGEM
Justin Turner, Assistant Chief Counsel, CalGEM
Caryn Craig, Senior Attorney, CalGEM
Christine Cowsert, Vice President, PG&E
[redacted], Director, PG&E
[redacted], Director, PG&E
[redacted], Senior Director, PG&E
[redacted], Chief, PG&E
[redacted], Senior Counsel, PG&E

PG&E Revised Implementation Plan and Inspection
Schedule January 15, 2021

Well Name (Abbreviated)	API Number	CalGEM Group Designation per September 30, 2020 Letter	Planned Year of Rework for T&P Conversion	Year of 1st MFL and/or UST Inspection (2013-2018)	CA - Thru-Tubing	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P
						13	45	0	2	19	49	0	1	14	30	0	3	12	50	0	6	11	27	0	10	0	34	11	19	0	47	17	0
					2018	2019				2020				2021				2022				2023				2024				2025			
McDonald Island																																	
2019 Well Assessments & Conversions to T&P																																	
WS-7W	0407720193	Group 1	2019			1									1								1					1			1		
WS-14E	0407720257	Group 1	2019			1	1								1								1					1			1		
WS-11E	0407720253	Group 1	2019			1									1								1					1			1		
WS-8E	0407720188	Group 1	2019			1	1								1								1					1			1		
WS-6E	0407720185	Group 1	2019			1									1								1					1			1		
TC-2S	0407720219	Group 1	2019			1									1								1					1			1		
TC-7S	0407720206	Group 1	2019			1									1								1					1			1		
TC-12S	0407720248	Group 2	2019	2014					1						1								1					1			1		
ZUCK-1	0407700091	Group 1	2019			1	1								1								1					1			1		
ROB-1	0407720524	Group 1	2019			1									1								1					1			1		
2020 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-16W	0407720231	Group 1	2020							1									1								1					1	
WS-11W	0407720265	Group 1	2020				1			1									1								1					1	
WS-13E	0407720256	Group 1	2020				1			1									1								1					1	
WS-12E	0407720255	Group 1	2020							1									1								1					1	
WS-7E	0407720187	Group 1	2020							1									1								1					1	
WS-5E	0407720179	Group 1	2020							1									1								1					1	
WS-4E	0407720178	Group 1	2020				1			1									1								1					1	
WS-1AE	0407720536	Group 2	2020				1			1									1								1					1	
TC-12N	0407720230	Group 2	2020							1									1								1					1	
MCD-11	0407700086	Group 2	2020				1			1									1								1					1	
ZUCK-H	0407720010	Group 1	2020				1			1									1								1					1	
WS-9E	0407720189	Group 1	2020							1									1								1					1	
MCD-12	0407700087	Group 1	2020				1			1									1								1					1	
MCD-10	0407700085	Group 2	2020							1	1								1								1					1	
TC-10S	0407720251	Group 1	2020				1			1									1								1					1	
WS-1E	0407720168	Group 2	2020/2021				1			1				1					1								1						
2021 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-9W	0407720195	Group 3	2021								1			1									1								1		
WS-5W	0407720211	Group 2	2021				1							1									1								1		
WS-4W	0407720214	Group 3	2021								1			1									1								1		
WS-3W	0407720213	Group 2	2021				1							1									1								1		
WS-2W	0407720212	Group 2	2021				1							1									1								1		
TC-11N	0407720229	Group 2	2021	2013							1						1						1								1		
TC-3S	0407720216	Group 2	2021				1							1									1								1		
TC-4S	0407720203	Group 2	2021				1							1									1								1		
TC-6S	0407720205	Group 2	2021	2018							1						1						1								1		
TC-8S	0407720533	Group 2	2021	2014							1						1						1								1		
TC-11S	0407720250	Group 2	2021				1							1									1								1		
MCD-13	0407700088	Group 2	2021				1							1									1								1		
LMac-1	0407720609	Group 2	2021				1							1									1								1		
2022 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-18W	0407720465	Group 2	2022				1								1			1									1						
WS-10E	0407720190	Group 2	2022				1								1			1									1						
TC-1N	0407720196	Group 2	2022	2013							1										1						1						
TC-2N	0407720199	Group 2	2022	2013, 2018							1										1						1						
TC-5N	0407720207	Group 2	2022								1							1									1						
TC-6N	0407720208	Group 2	2022								1							1									1						
TC-13N	0407720234	Group 2	2022				1								1			1									1						
TC-15N	0407720239	Group 2	2022	2017							1										1						1						
TC-16N	0407720240	Group 2	2022				1								1			1									1						
TC-17N	0407720548	Group 2	2022	2014							1										1						1						
TC-5S	0407720204	Group 2	2022	2016							1										1						1						
MCD-5A	0407720552	Group 2	2022				1								1			1									1						
MCD-14	0407720441	Group 2	2022				1								1			1									1						
MCD-9	0407700084	Group 2	2022	2016			1								1						1						1						
2023 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-20W	0407720535	Group 2	2023	2018	CA - TT						1								1						1						1		
WS-19W	0407720467	Group 2	2023	2018							1								1						1						1		
WS-17W	0407720166	Group 2	2023	2018							1								1						1						1		
WS-15W	0407720233	Group 3	2023								1											1									1		
WS-14W	0407720238	Group 2	2024				1								1							1									1		
WS-10W	0407720534	Group 2	2023				1								1							1									1		
WS-1W	0407720215	Group 2	2023	2015							1								1						1						1		
TC-3N	0407720201	Group 2	2023	2016							1								1						1						1		
TC-8N	0407720226	Group 2	2023	2014							1								1						1						1		
TC-9S	0407720252	Group 2	2023	2014							1								1						1						1		
TC-13S	0407720247	Group 2	2023	2014							1								1						1						1		
TC-14S	0407720244	Group 2	2023	2015							1								1						1						1		
TC-15S	0407720245	Group 2	2023	2015							1								1						1						1		
MCD-15	0407720444	Group 2	2023				1								1							1									1		
MCD-4	0407700080	Group 2	2023				1								1							1									1		
MCD-7	0407700083	Group 3	2023								1								1			1									1		
MCD-6	0407700082	Group 3	2023								1								1			1											
2024 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-13W	0407720241	Group 2	2024	2018							1								1										1				
WS-12W	0407720264	Group 2	2024	2018							1								1										1				
WS-8W	0407720194	Group 2	2024	2018							1								1										1				
WS-1AW	0407720544	Group 2	2024	2018							1								1										1				
WS-2E	0407720169	Group 2	2024	2017							1								1										1				
TC-4N	0407720202	Group 2	2024	2016	CA - TT						1								1										1				
TC-7N	0407720225	Group 2	2024	2016, 2017							1								1										1				
TC-9N	0407720227	Group 2	2024	2016	CA - TT						1								1										1				
TC-10N	0407720228	Group 2	2024	2013, 2016, 2017							1								1										1				
TC-1S	0407720218	Group 2	2024	2018							1								1										1				
TC-17S	0407720258	Group 2	2024	2018							1								1										1				
WS-6W	0407720192	Group 2	2024	2018							1								1										1				
WS-3E	0407720173	Group 2	2024	2016, 2017	CA - TT		1								1				1										1				
TC-1AS	0407720551	Group 2	2024	2016							1								1										1				
TC-16S	0407720243	Group 2	2024	2018							1								1										1				

Note: The plan shown is based upon the information at the time of publication and is subject to change should new information require adjustment. The order of wells listed does not reflect planned execution sequencing in year.

PG&E Revised Implementation Plan and Inspection Schedule
January 15, 2021

Well Name (Abbreviated)	API Number	CalGEM Group Designation per September 30, 2020 Letter	Planned Year of Rework for T&P Conversion	Year of 1st MFL and/or UST Inspection (2013-2018)	2018 CA - Thru-Tubing	2019 RW Convert- T&P, CA, PT	2019 CA - Thru-Tubing	2019 PT (Post Conversion to T&P)	2019 Re-assess CA, PT, T&P	2020 RW Convert- T&P, CA, PT	2020 CA - Thru-Tubing	2020 PT (Post Conversion to T&P)	2020 Re-assess CA, PT, T&P	2021 RW Convert- T&P, CA, PT	2021 CA - Thru-Tubing	2021 PT (Post Conversion to T&P)	2021 Re-assess CA, PT, T&P	2022 RW Convert- T&P, CA, PT	2022 CA - Thru-Tubing	2022 PT (Post Conversion to T&P)	2022 Re-assess CA, PT, T&P	2023 RW Convert- T&P, CA, PT	2023 CA - Thru-Tubing	2023 PT (Post Conversion to T&P)	2023 Re-assess CA, PT, T&P	2024 RW Convert- T&P, CA, PT	2024 CA - Thru-Tubing	2024 PT (Post Conversion to T&P)	2024 Re-assess CA, PT, T&P	2025 RW Convert- T&P, CA, PT	2025 CA - Thru-Tubing	2025 PT (Post Conversion to T&P)	2025 Re-assess CA, PT, T&P
						13	45	0	2	19	49	0	1	14	30	0	3	12	50	0	6	11	27	0	10	0	34	11	19	0	47	17	0
Los Medanos																																	
2019 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-15C	0401320121	Group 1	2019			1									1								1					1			1		
2020 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-20D	0401320297	Group 1	2020				1			1									1													1	
LM-11C	0401320128	Group 1	2020	2013									1						1													1	
2021 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-17D	0401320136	Group 2	2021								1			1									1								1		
LM-10C	0401320131	Group 2	2021								1			1									1								1		
LM-16D	0401320133	Group 2	2021								1			1									1								1		
2022 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-6B	0401320140	Group 2	2022				1								1			1									1						
LM-3A	0401320115	Group 2	2022				1								1			1									1						
LM-19D	0401320295	Group 2	2022				1								1			1									1						
LM-7C	0401320130	Group 2	2022				1								1			1									1						
2023 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-21D	0401320308	Group 2	2023								1								1			1									1		
LM-14C	0401320298	Group 2	2023				1								1							1									1		
LM-13C	0401320299	Group 2	2023				1								1							1									1		
LM-9C	0401320123	Group 2	2023				1								1							1									1		
2024 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-12C	0401320307	Group 2	2024	2016							1								1										1				
GINO-3	0401300135	N/A	2024	2017							1								1										1				
LM-2A	0401320138	Group 2	2024	2016							1								1										1				
LM-5B	0401320144	Group 2	2024	2013							1								1										1				
Plugged Wells 2019-2020						2019				2020				2021				2022				2023				2024				2025			
LM-4B	0401320093	NA - P&A	2019	2013					1																								
PC 4-1	0411300064	NA - P&A	2019			1																											
TILD-1	0407700090	NA - P&A	2019			1																											
ZUCK-3	0407700093	NA - P&A	2019			1	1																										
LM-1A	0401320373	NA - P&A	2020				1			1																							
ROB-2	0407720523	NA - P&A	2020							1																							
Pleasant Creek - IN THE PROCESS OF BEING SOLD OR DECOMMISSIONED																																	
PC 3-1	0411300063	Group 4	N/A																														
PC 3-2	0411320192	Group 4	N/A				1																										
PC 3-3	0411320193	Group 4	N/A				1																										
PC 3-4	0411320194	Group 4	N/A																														
PC 3-5	0411321279	Group 4	N/A	2012							1																						
PC 4-2	0411320195	Group 4	N/A				1																										

No further work is planned as the Pleasant Creek facility as it is currently pending either a sale as a production field or will be decommissioned.

Note: The plan shown is based upon the information at the time of publication and is subject to change should new information require adjustment. The order of wells listed does not reflect planned execution sequencing in year.

California
Department of Conservation
Geologic Energy Management Division

Gavin Newsom, Governor
David Shabazian, Director

June 15, 2021

TRANSMITTED VIA ELECTRONIC MAIL
Pacific Gas and Electric Company
Attention: [redacted]
6121 Bollinger Canyon Road
San Ramon, CA 94583

UNDERGROUND GAS STORAGE WELLS TESTING SCHEDULE DETERMINATION

Dear [redacted]:

This letter follows up on our prior correspondence to Pacific Gas and Electric Company (PG&E): the September 30, 2020 letter titled "Underground Gas Storage Wells Interim Conditional Testing Schedule" that allowed an interim testing period; and the May 12, 2021 letter titled, "June 15, 2021 Extension For Underground Gas Storage Wells Interim Conditional Testing Schedule" that extended the interim testing period while the Geologic Energy Management Division (CalGEM) further considered portions of PG&E's Risk Management Plan relating to mechanical integrity testing requirements. CalGEM appreciates the correspondence and monthly engagements with PG&E in developing an acceptable well-specific mechanical integrity testing schedule. For reference, a brief overview of these efforts is summarized below.

Mechanical Integrity Testing Schedule Development

Section 1726.6 of CalGEM's underground gas storage (UGS) regulations[1] sets forth three mechanical integrity testing (MIT) requirements for every well that penetrates a gas storage reservoir and is not plugged and abandoned. The two requirements at issue are the casing wall thickness inspection and the pressure test.

Section 1726.6, subdivision (a)(2) requires casing wall thickness inspection every 24 months, or at an alternative frequency based on the demonstrated casing wall thickness and demonstrated corrosion rate. The regulations contemplated that such an alternative frequency will be based on at least two rounds of inspections with the first round due by October 1, 2020. Section 1726.6, subdivision (a)(3), requires pressure testing of gas storage wells on a "well-specific minimum pressure testing frequency" based on risk management analysis that has been reviewed and approved by CalGEM. If a well-specific pressure testing frequency has not been established and

[1] CalGEM's Underground Gas Storage regulations are found in California Code of Regulations, title 14, sections 1726 through 1726.10.

approved, then pressure testing must be done every 24 months. For these wells, the first pressure test was due by October 1, 2020.

As of September 30, 2020, PG&E had submitted a testing plan and had been in active discussions with CalGEM regarding PG&E's proposed schedule for testing wells in accordance with the regulations. However, PG&E did not have an approved alternative casing inspection testing frequency or approved well-specific minimum pressure testing frequency for any of its wells. Based on CalGEM's evaluation of each well and general well safety conditions, as explained in more detail in our September 30, 2020 letter, we approved an "interim" testing schedule until April 1 (later extended to May 15 and then June 15) 2021. During that interim period, PG&E was to either submit a revised testing plan and schedule for CalGEM to review and approve for each well that had not had the required casing thickness inspection or pressure testing by October 1, 2020; or complete required casing thickness inspections and pressure testing; or suspend use of the untested well(s) for injection or withdrawal of gas.

Since September 2020, CalGEM and PG&E have met at least monthly to discuss PG&E's testing progress and proposed schedule, including well prioritization criteria, operational impacts and limitations.

The engagement led to PG&E submitting a revised proposed testing schedule (referred to by PG&E as its "Revised Implementation Plan") on January 15, 2021 for calendar years 2021 through 2024. The proposed testing schedules are located on pages 6 and 7 in the Revised Implementation Plan (Enclosed). Under the revised schedule, PG&E would complete all initial casing thickness inspections and well pressure tests required by section 1726.6 for listed PG&E wells by the end of the 2024 calendar year. CalGEM's references to PG&E's schedule or revised schedule in the remainder of this letter are referring to the schedules in the two pages enclosed hereto.

Well Safety Considerations and Well Prioritization

Well safety is of paramount importance as CalGEM considers the safety systems in place for each well and the revised schedule submitted by PG&E. During the interim testing period, PG&E demonstrated wells have been able to be safely used and continue to operate under the following well safety considerations:

- PG&E employs SCADA systems for monitoring all of its wells;
    - The systems monitor pressure on both the tubing and all annuli;
    - The systems run at all times and are monitored by personnel at all times;
    - Personnel have the ability to manually shut in the systems;
- All of the wells have leak detection technology employed at the wellhead and is monitored daily;

- Detailed well casing diagrams have been provided to CalGEM for each of the wells; and
- Each of the wells has had successful noise and temperature logs run on them in the past year.

In addition to these safety systems, CalGEM has evaluated PG&E's relative prioritization of wells for testing, as presented in the revised schedule, as well as the detailed risk methodology employed by PG&E. CalGEM found substantial correlation between its own testing priority analysis and PG&E's prioritization. This important step allows CalGEM to concur with PG&E's well prioritization and order for testing over the multiyear schedule and conclude the order in which wells are scheduled to be tested is appropriate.

CalGEM Determination Regarding Schedule

Based on available data and CalGEM's evaluation of well safety considerations and analysis, CalGEM has determined that each of PG&E's wells that have yet to have the initial round of testing required by section 1726.6 - a pressure test and direct casing thickness inspection using magnetic flux or ultrasonic technologies - can continue injection and withdrawal through 2024 according to PG&E's Revised Implementation Plan with the following conditions:

1. PG&E must conduct through-tubing casing evaluation on all wells that have not had initial or second direct measurement casing wall thickness inspections at least once annually. The frequency between logs should be no less than a 12-month period of each other and should not exceed 15 months. PG&E may elect for this logging to be simultaneous with the yearly Noise and Temperature evaluation. Discussion of specifications for through-tubing technology is found in the next section.
2. PG&E must pressure test the tubing-casing annulus at least every 24 months on each of the wells that have been converted to tubing and packer, at least until a second direct measurement casing wall thickness inspection is performed, a corrosion rate can be determined, and an alternative testing frequency is approved by CalGEM, on a well-by-well basis. Each well shall be tested to 115 percent of maximum allowable injection pressure at the wellhead in accordance to section 1726.6.1(a)(4).
3. PG&E will provide CalGEM with monthly reporting of work planned and previous monthly work completed by the first Friday of each month, using a template to be provided by CalGEM, starting July 2021. If circumstances occur in which PG&E has an unanticipated delay or deviation from the approved schedule, PG&E must inform CalGEM as soon as reasonable, but no later than 10 calendar days after PG&E learns that planned work cannot be completed in full

accordance with the approved schedule. PG&E's reporting should explain the cause of the delay and how PG&E plans to accomplish the work in a timely manner and remain on schedule.

If a well has not had the initial casing wall thickness inspection and pressure testing completed by December 31, 2024, then the well must not be used for injection or withdrawal of gas after that date until the inspection and testing is complete and subsequent use is authorized by CalGEM. Use of unauthorized wells or failure to report in accordance with condition 3 of this section will be subject to enforcement action.

CalGEM Determination Regarding Casing Inspection Methodology

Incorporated in the revised testing schedule, PG&E plans to continue to utilize through-tubing technologies until it is able to utilize magnetic flux or ultrasonic technology that is not run through-tubing on all wells, as required under regulation. CalGEM agrees utilizing through-tubing technology has qualitative value while wells await magnetic flux or ultrasonic technology logging. CalGEM expects PG&E to utilize the newest through-tubing technologies with the highest performance standards and seek agreement with CalGEM on establishing trigger thresholds for anomalies found that may require additional investigations and testing moving forward. New well integrity information discovered with through-tubing technologies in the future may require adjustments to the well prioritization, testing schedule, or both.

However, PG&E and CalGEM agree through-tubing technologies have limitations and at this time cannot replace magnetic flux or ultrasonic technologies to satisfy the requirements of the casing wall thickness inspection of section 1726.6. Therefore, PG&E will be required to use magnetic flux or ultrasonic technology to meet the initial casing inspection testing requirements for each of its wells that have not already had such an inspection and the secondary casing inspection testing requirements to establish a corrosion rate to support a less frequent casing wall thickness inspection schedule.

CalGEM is currently evaluating the proposal submitted by PG&E through their Risk Management Plan addressing the timeline for completion of the second casing wall thickness inspections on all wells. The schedule approved in this letter is for only the wells that have not had the initial casing wall thickness testing. The conditional testing required in conditions 1 and 2 above will remain in place for each well until a second casing wall thickness inspection is performed, a corrosion rate can be determined, and appropriate testing frequencies for both pressure tests and casing inspections can be established on a well-by-well basis. These requirements exclude Pleasant Creek wells, which are proposed by PG&E to be decommissioned and as such, are being addressed separately.

CalGEM anticipates working closely with you to coordinate on testing, inspections, progress made under the approved schedule, and approval of the second casing wall thickness inspection schedule. Please continue to work with Rich Boyd as the primary point of contact moving forward.

Sincerely,

Uduak Joe-Ntuk
State Oil and Gas Supervisor

Enclosure (1): PG&E Implementation Plan

CC:
Courtney Smith, Chief Deputy of Programs
Yuvaraj Sivalingam, Deputy Supervisor Policy and Administration
Emily Reader, Programs II Manager
Rich Boyd, UGS Program Supervisor
Charlene Wardlow, Northern District Deputy
Lucy Redmond, PG&E Director, Reservoir Engineering

PG&E Revised Implementation Plan and Inspection
Schedule January 15, 2021

Well Name (Abbreviated)	API Number	CalGEM Group Designation per September 30, 2020 Letter	Planned Year of Rework for T&P Conversion	Year of 1st MFL and/or UST Inspection (2013-2018)	2018 CA - Thru-Tubing	2019 RWConvert- T&P, CA, PT	2019 CA - Thru-Tubing	2019 PT (Post Conversion to T&P)	2019 Re-assess CA, PT, T&P	2020 RWConvert- T&P, CA, PT	2020 CA - Thru-Tubing	2020 PT (Post Conversion to T&P)	2020 Re-assess CA, PT, T&P	2021 RWConvert- T&P, CA, PT	2021 CA - Thru-Tubing	2021 PT (Post Conversion to T&P)	2021 Re-assess CA, PT, T&P	2022 RWConvert- T&P, CA, PT	2022 CA - Thru-Tubing	2022 PT (Post Conversion to T&P)	2022 Re-assess CA, PT, T&P	2023 RWConvert- T&P, CA, PT	2023 CA - Thru-Tubing	2023 PT (Post Conversion to T&P)	2023 Re-assess CA, PT, T&P	2024 RWConvert- T&P, CA, PT	2024 CA - Thru-Tubing	2024 PT (Post Conversion to T&P)	2024 Re-assess CA, PT, T&P	2025 RWConvert- T&P, CA, PT	2025 CA - Thru-Tubing	2025 PT (Post Conversion to T&P)	2025 Re-assess CA, PT, T&P
						13	45	0	2	19	49	0	1	14	30	0	3	12	50	0	6	11	27	0	10	0	34	11	19	0	47	17	0
McDonald Island																																	
2019 Well Assessments & Conversions to T&P																																	
WS-7W	0407720193	Group 1	2019			1									1								1					1			1		
WS-14E	0407720257	Group 1	2019			1	1								1								1					1			1		
WS-11E	0407720253	Group 1	2019			1									1								1					1			1		
WS-8E	0407720188	Group 1	2019			1	1								1								1					1			1		
WS-6E	0407720185	Group 1	2019			1									1								1					1			1		
TC-2S	0407720219	Group 1	2019			1									1								1					1			1		
TC-7S	0407720206	Group 1	2019			1									1								1					1			1		
TC-12S	0407720248	Group 2	2019	2014					1						1								1					1			1		
ZUCK-1	0407700091	Group 1	2019			1	1								1								1					1			1		
ROB-1	0407720524	Group 1	2019			1									1								1					1			1		
2020 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-16W	0407720231	Group 1	2020							1									1								1					1	
WS-11W	0407720265	Group 1	2020				1			1									1								1					1	
WS-13E	0407720256	Group 1	2020				1			1									1								1					1	
WS-12E	0407720255	Group 1	2020							1									1								1					1	
WS-7E	0407720187	Group 1	2020							1									1								1					1	
WS-5E	0407720179	Group 1	2020							1									1								1					1	
WS-4E	0407720178	Group 1	2020				1			1									1								1					1	
WS-1AE	0407720536	Group 2	2020				1			1									1								1					1	
TC-12N	0407720230	Group 2	2020							1									1								1					1	
MCD-11	0407700086	Group 2	2020				1			1									1								1					1	
ZUCK-H	0407720010	Group 1	2020				1			1									1								1					1	
WS-9E	0407720189	Group 1	2020							1									1								1					1	
MCD-12	0407700087	Group 1	2020				1			1									1								1					1	
MCD-10	0407700085	Group 2	2020							1	1								1								1					1	
TC-10S	0407720251	Group 1	2020				1			1									1								1					1	
WS-1E	0407720168	Group 2	2020/2021				1			1				1					1								1						
2021 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-9W	0407720195	Group 3	2021								1			1									1								1		
WS-5W	0407720211	Group 2	2021				1							1									1								1		
WS-4W	0407720214	Group 3	2021								1			1									1								1		
WS-3W	0407720213	Group 2	2021				1							1									1								1		
WS-2W	0407720212	Group 2	2021				1							1									1								1		
TC-11N	0407720229	Group 2	2021	2013							1						1						1								1		
TC-3S	0407720216	Group 2	2021				1							1									1								1		
TC-4S	0407720203	Group 2	2021				1							1									1								1		
TC-6S	0407720205	Group 2	2021	2018							1						1						1								1		
TC-8S	0407720533	Group 2	2021	2014							1						1						1								1		
TC-11S	0407720250	Group 2	2021				1							1									1								1		
MCD-13	0407700088	Group 2	2021				1							1									1								1		
LMac-1	0407720609	Group 2	2021				1							1									1								1		
2022 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-18W	0407720465	Group 2	2022				1								1			1									1						
WS-10E	0407720190	Group 2	2022				1								1			1									1						
TC-1N	0407720196	Group 2	2022	2013							1										1						1						
TC-2N	0407720199	Group 2	2022	2013, 2018							1										1						1						
TC-5N	0407720207	Group 2	2022								1							1									1						
TC-6N	0407720208	Group 2	2022								1							1									1						
TC-13N	0407720234	Group 2	2022				1								1			1									1						
TC-15N	0407720239	Group 2	2022	2017							1										1						1						
TC-16N	0407720240	Group 2	2022				1								1			1									1						
TC-17N	0407720548	Group 2	2022	2014							1										1						1						
TC-5S	0407720204	Group 2	2022	2016							1										1						1						
MCD-5A	0407720552	Group 2	2022				1								1			1									1						
MCD-14	0407720441	Group 2	2022				1								1			1									1						
MCD-9	0407700084	Group 2	2022	2016			1								1						1						1						
2023 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-20W	0407720535	Group 2	2023	2018	CA - TT						1								1						1						1		
WS-19W	0407720467	Group 2	2023	2018							1								1						1						1		
WS-17W	0407720166	Group 2	2023	2018							1								1						1						1		
WS-15W	0407720233	Group 3	2023								1											1									1		
WS-14W	0407720238	Group 2	2024				1								1							1									1		
WS-10W	0407720534	Group 2	2023				1								1							1									1		
WS-1W	0407720215	Group 2	2023	2015							1								1						1						1		
TC-3N	0407720201	Group 2	2023	2016							1								1						1						1		
TC-8N	0407720226	Group 2	2023	2014							1								1						1						1		
TC-9S	0407720252	Group 2	2023	2014							1								1						1						1		
TC-13S	0407720247	Group 2	2023	2014							1								1						1						1		
TC-14S	0407720244	Group 2	2023	2015							1								1						1						1		
TC-15S	0407720245	Group 2	2023	2015							1								1						1						1		
MCD-15	0407720444	Group 2	2023				1								1							1									1		
MCD-4	0407700080	Group 2	2023				1								1							1									1		
MCD-7	0407700083	Group 3	2023								1								1			1									1		
MCD-6	0407700082	Group 3	2023								1								1			1											
2024 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
WS-13W	0407720241	Group 2	2024	2018							1								1										1				
WS-12W	0407720264	Group 2	2024	2018							1								1										1				
WS-8W	0407720194	Group 2	2024	2018							1								1										1				
WS-1AW	0407720544	Group 2	2024	2018							1								1										1				
WS-2E	0407720169	Group 2	2024	2017							1								1										1				
TC-4N	0407720202	Group 2	2024	2016	CA - TT						1								1										1				
TC-7N	0407720225	Group 2	2024	2016, 2017							1								1										1				
TC-9N	0407720227	Group 2	2024	2016	CA - TT						1								1										1				
TC-10N	0407720228	Group 2	2024	2013, 2016, 2017							1								1										1				
TC-1S	0407720218	Group 2	2024	2018							1								1										1				
TC-17S	0407720258	Group 2	2024	2018							1								1										1				
WS-6W	0407720192	Group 2	2024	2018							1								1										1				
WS-3E	0407720173	Group 2	2024	2016, 2017	CA - TT		1								1				1										1				
TC-1AS	0407720551	Group 2	2024	2016							1								1										1				
TC-16S	0407720243	Group 2	2024	2018							1								1										1				

Note: The plan shown is based upon the information at the time of publication and is subject to change should new information require adjustment. The order of wells listed does not reflect planned execution sequencing in year.

PG&E Revised Implementation Plan and Inspection Schedule
January 15, 2021

Well Name (Abbreviated)	API Number	CalGEM Group Designation per September 30, 2020 Letter	Planned Year of Rework for T&P Conversion	Year of 1st MFL and/or UST Inspection (2013-2018)	CA - Thru-Tubing	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P	RW Convert- T&P, CA, PT	CA - Thru-Tubing	PT (Post Conversion to T&P)	Re-assess CA, PT, T&P
						13	45	0	2	19	49	0	1	14	30	0	3	12	50	0	6	11	27	0	10	0	34	11	19	0	47	17	0
					2018	2019				2020				2021				2022				2023				2024				2025			
Los Medanos																																	
2019 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-15C	0401320121	Group 1	2019			1									1								1					1			1		
2020 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-20D	0401320297	Group 1	2020				1			1									1													1	
LM-11C	0401320128	Group 1	2020	2013									1						1													1	
2021 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-17D	0401320136	Group 2	2021								1			1									1								1		
LM-10C	0401320131	Group 2	2021								1			1									1								1		
LM-16D	0401320133	Group 2	2021								1			1									1								1		
2022 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-6B	0401320140	Group 2	2022				1								1			1									1						
LM-3A	0401320115	Group 2	2022				1								1			1									1						
LM-19D	0401320295	Group 2	2022				1								1			1									1						
LM-7C	0401320130	Group 2	2022				1								1			1									1						
2023 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-21D	0401320308	Group 2	2023								1								1			1									1		
LM-14C	0401320298	Group 2	2023				1								1							1									1		
LM-13C	0401320299	Group 2	2023				1								1							1									1		
LM-9C	0401320123	Group 2	2023				1								1							1									1		
2024 Well Assessments & Conversions to T&P						2019				2020				2021				2022				2023				2024				2025			
LM-12C	0401320307	Group 2	2024	2016							1								1										1				
GINO-3	0401300135	N/A	2024	2017							1								1										1				
LM-2A	0401320138	Group 2	2024	2016							1								1										1				
LM-5B	0401320144	Group 2	2024	2013							1								1										1				

Plugged Wells 2019-2020						2019				2020				2021				2022				2023				2024				2025			
LM-4B	0401320093	NA - P&A	2019	2013					1																								
PC 4-1	0411300064	NA - P&A	2019			1																											
TILD-1	0407700090	NA - P&A	2019			1																											
ZUCK-3	0407700093	NA - P&A	2019			1	1																										
LM-1A	0401320373	NA - P&A	2020				1			1																							
ROB-2	0407720523	NA - P&A	2020							1																							

Pleasant Creek - IN THE PROCESS OF BEING SOLD OR DECOMMISSIONED																																	
PC 3-1	0411300063	Group 4	N/A																														
PC 3-2	0411320192	Group 4	N/A				1																										
PC 3-3	0411320193	Group 4	N/A				1																										
PC 3-4	0411320194	Group 4	N/A																														
PC 3-5	0411321279	Group 4	N/A	2012							1																						
PC 4-2	0411320195	Group 4	N/A				1																										

No further work is planned as the Pleasant Creek facility as it is currently pending either a sale as a production field or will be decommissioned.

Note: The plan shown is based upon the information at the time of publication and is subject to change should new information require adjustment. The order of wells listed does not reflect planned execution sequencing in year.

California
Department of Conservation
Geologic Energy Management Division

Gavin Newsom, Governor
David Shabazian, Director

April 11, 2023

[redacted]
77 Beale Street
San Francisco, CA 94105

Delivered via **ELECTRONIC MAIL**:
Jeanette.Hand@conservation.ca.gov

SUBJECT: PROPOSED MECHANICAL INTEGRITY TESTING SCHEDULE

This letter follows up on the California Geologic Energy Management Division's (CalGEM's) previous communications with Pacific Gas and Electric Company (PG&E) about the second round of casing wall thickness testing required by California Code of Regulations (CCR), title14, section 1726.6, and responds to PG&E's proposed Reinspection Plan schedule for mechanical integrity testing (MIT) received January 20, 2023.

CalGEM and PG&E agreed upon a schedule for the first round of MIT on underground gas storage (UGS) wells and well conversion (CCR section 1726.3(d)(1)) through 2024, documented in the UGS wells testing schedule determination letter dated June 15, 2021.

With the testing schedule through 2024 established, CalGEM and PG&E agreed that proactive, early development should begin on the schedule for one time approval of the next round of well testing. CalGEM asked PG&E to initiate this process. PG&E was tasked with developing a proposed testing schedule that improved upon the first-round schedule, which provided supporting data, narratively explained how the wells were prioritized, and detailed how the schedule was created.

PG&E's January 2023 Reinspection Plan

CalGEM has reviewed PG&E's proposed testing plan and identified key areas of concern with PG&E's proposed testing schedule:

- The next casing wall thickness inspection would be performed five to fifteen years after a well's previous inspection. Further, 93% of wells are proposed to have their next inspection eight years or more after their last inspection. The agreed-upon schedule for the first round of MIT testing completes the first round of testing within six years. It remains unclear what is driving a proposed testing timeframe for the second round of MIT testing that is significantly longer than what was agreed to and has been followed to-date for the first round of MIT testing. The proposed schedule for this single round of testing is much longer than the six-year timeframe that CalGEM approved for the first round of testing, the two-year timeframe contemplated in under CalGEM's MIT testing requirements, and even the seven-year timeframe presented in testimony by PG&E.[1]
- Wells with up to 60% casing wall loss would remain untested for up to fifteen years.

[1] In testimony before the California Public Utilities Commission, PG&E stated in July, 2022, that "Due to the continued uncertainty in the regulations governing planned work in this area, PG&E is forecasting reinspection with direct methods to occur on a 7-year cycle."

- There is no articulated plan for communicating with and seeking concurrence from CalGEM on the potential need for deviations from the proposed schedule.
- The plan considers potential risks associated with an assumed reoccurring inspection interval that has not yet been established, rather than focusing on the next round of testing—the only known at this time.
- The plan attributes nearly all wall loss to mechanical damage with insufficient data to support that conclusion.
- Additionally, corrosion calculations rely on only one data point measuring casing wall loss compared against the nominal casing wall thickness. Due to the 12.5% thickness variation allowed in API casings, utilizing the nominal thickness (and not measured via casing wall thickness testing) of the casing compared against the first measurement does not have appropriate level of accuracy and confidence to calculate a metal loss/ corrosion growth rate.

Additional Feedback Regarding Concerns about Mechanical Damage from Testing

PG&E's primary rationale for significantly extending its testing intervals, despite the absence of a second casing wall thickness test, and notwithstanding casing wall loss, is focused on the risks of possible damage caused by well testing itself. PG&E and other commenters raised the issue of the potential for mechanical damage during the public rulemaking that preceded the adoption of CCR section 1726.6, and those concerns were considered as part of the rulemaking process. Public Resources Code (PRC) section 3180, subdivision (b), required CalGEM to specify a MIT testing regime that includes regular leak testing, casing wall thickness inspection, pressure testing of the production casing, and other testing deemed necessary by CalGEM. PRC section 3180, subdivision (d)(4), directed CalGEM to develop regulations that established a schedule for ongoing MIT. CalGEM developed the testing regime in CCR section 1726.6 in consultation with scientists from the National Labs and based on the scientific understanding of the risk associated with corrosion in UGS wells. Application of PG&E's rationale to the exclusion of other considerations, such as corrosion, suggests no MIT should be performed on a well. Performing MIT on all wells that penetrate the reservoir is required by regulations and supported by the American Petroleum Institute Recommended Practice 1171, section 9.3.1.

CCR section 1726.6 requires the establishment of a corrosion rate before a less frequent casing thickness inspection schedule can be approved. CalGEM has had previous discussions with PG&E to reconfirm the regulatory requirement and rationale for obtaining a second data point to establish this corrosion rate. PG&E's recent Reinspection Plan does not reflect those discussions and is inconsistent with regulatory requirements. PG&E's proposed schedule is based on incomplete corrosion rate data, and as such, lacks basis for extended mechanical integrity reinspection intervals and cannot be acted upon by CalGEM.

Expected Reinspection Plan Improvements

The regulations establish a default 24-month testing interval for conducting pressure testing and casing thickness inspection on each well, unless and until CalGEM approves a less frequent MIT schedule based on well-specific data and analysis. PG&E has so far complied with a six-year schedule for their first-round of testing, with CalGEM's approval based on demonstrations that additional safety factors, including Supervisory Control and Data Acquisition (SCADA) systems, leak detection technology, and annual temperature and noise logs, could monitor well safety throughout the duration of that testing.

CalGEM expects a proposed schedule equivalent to, or shorter than, that first round testing timeline. If PG&E believes that to be infeasible or problematic, PG&E must explain the rationale for this and make a demonstration, including provision of data and analysis, of the challenges and constraints. PG&E has posed concerns about maintaining reliability while performing necessary safety testing. PG&E must explain, its justification for its proposed schedule, why safe operation of the wells is assured in the interim and detail how a shorter reinspection timeframe will impact system reliability, supported by data. If PG&E cannot substantiate the basis for a given schedule, wells that cannot be tested within an acceptable timeframe may be required to be shut in pursuant to PRC section 1726.6(a)(2) and (3).

PG&E must submit a casing inspection schedule that focuses on the feasibility of this second round of testing, and not reflect consideration of potential risk associated with an assumed ongoing reinspection interval, as that is not able to be known at this time without established corrosion rates.

CalGEM has identified the following information, data and assumptions that need to be incorporated by PG&E in an updated proposal for its reinspection plan:

- This plan must include a testing schedule for every well that penetrates a gas storage reservoir and is not plugged and abandoned.
- The plan must include an explanation, accompanied by this submittal to CalGEM of clear and supporting data, of PG&E's justification for its proposed schedule, why safe operation of the wells is assured in the interim and detail what constraints impact the reinspection schedule, including any reliability impacts. Each constraint should be explained clearly, supported by data and documentation, demonstrating why PG&E cannot reinspect on the same timeframe as before, if not sooner. Generalized, unsupported assertions cannot be evaluated or approved.
- The updated proposed plan should not reflect any potential risk associated with undetermined ongoing testing interval frequencies, and instead should focus on the testing schedule for a single round of testing after 2024.
- The plan should provide well-specific flow rates based on well configuration during the duration of the testing schedule. (For example, if the proposal covers 6 years, the flow rate should reflect the well configuration between 2025-2030).
- The plan should include a statement that any deviation from the final approved schedule shall be approved in advance and in writing by CalGEM.

- The classification of MIT Interval (flowchart on P27) is based on class of metal loss and assessment of apparent growth. This information should be provided on the Well-by-Well Integration Inspection Summary table (P32) – Appendix B
- The narrative portion of the schedule should explain the methodology used to determine well testing prioritization and provide at least two demonstrative examples for each storage field, of PG&E applying the methodology to specific wells, using well-specific data, to establish the inspection plan on a well-by-well basis. CalGEM needs to understand PG&E's process and be able to evaluate that the scheduling proposed is based on risk. An explanation of the methodology and the conclusions alone are insufficient; PG&E should demonstrate why each well is appropriately scheduled.
- The narrative portion of the schedule should include an explanation of how through-tubing casing wall thickness testing can be utilized to support the testing schedule in addition to the required CWT testing. For example, testing on a specific interval to collect qualitative data between casing wall testing dates.
- First round testing indicated some wells have more significant wall loss than other wells. All else being equal, wells with the most damage should be prioritized for testing in the next round. If PG&E proposes to reinspect a more damaged well later than a less damaged one, PG&E should provide a risk-based, sufficiently detailed explanation why the more damaged well is not being tested before the less damaged well and why it is safe to continue using the more damaged well in the interim.
- The plan should provide the below data so CalGEM can independently audit the prioritization.
    - Documentation of all Class 2 and/or Class 3 anomalies.
    - Highest metal loss per well, depth of the greatest metal loss and the estimated corrosion rate where the data allows.
    - The tool information including, the reporting threshold and detection limit of the tool utilized for that test.
        - For inspections with no reported wall loss, maximum metal loss should be based on minimum reporting threshold of the tool. For example, in the table provided in Appendix A1 in your recent proposed reinspection plan, the Maximum Metal loss (%) from Inspection column should not reflect 0% when the reporting threshold of the tool utilized is 20%.
        - Columns for tool detection limit and reporting threshold of the tool utilized to perform the CWT inspection.
        - The metal loss % column should reflect the abilities of the tool utilized.
    - Wellbore diagrams showing the location of the damage compared to the location of dog legs or other sources of mechanical wear.
- Further, CalGEM is interested in learning more about the cross-compression program PG&E is developing, and how it could be utilized to further shorten the testing timeframe for PG&E's testing schedule.
- The previous submission expressed the timeline data in a spreadsheet, and that format is helpful to CalGEM's evaluation and a common understanding of the proposed schedule. Please include a similar spreadsheet of timeline data in the updated submission to facilitate CalGEM's review.

- The testing schedule shall account for standard annular pressure testing every 24 months in alignment with CCR section 1726.6(a)(3).

Deadline for Resubmission

May 23, 2023

CalGEM requests that PG&E update its next round reinspection plan in accordance with the expectations set forth in this letter, and submit the updated plan by email to Jeanette.Hand@conservation.ca.gov.

CalGEM is hoping to confirm an acceptable MIT schedule that provides for timely acquisition of necessary data to establish a corrosion rate and inform a comprehensive risk-based analysis that ensures that stored gas will be confined to the approved reservoir and that risks of damage to life, health, property, the environment, and natural resources are identified. The sooner that the necessary data and analysis are obtained, evaluated, and approved, the sooner that PG&E can undertake a demonstration that corrosion is not occurring and that longer reinspection intervals are appropriate.

To the extent that PG&E will assert that testing requirements implicate reliability issues and that the data necessary to CalGEM's evaluation of those reliability concerns are subject to confidential treatment, PG&E should communicate with CalGEM as soon as possible. The parties will need to timely resolve any confidentiality concerns so as to not delay the evaluation and approval of an inspection plan or result in the necessity to shut-in any wells for lack of timely and adequate testing.

Please reach out to CalGEM early and often with questions so we can expeditiously work through this process. Jeanette Hand will act as your primary point of contact. In follow up to this letter, CalGEM will schedule time to meet with PG&E representatives and staff to review our feedback and expectations, and we look forward to continuing to work together to perform timely testing requisite to ensure safety of PG&E's UGS facilities.

Thank you,

Gabe Tiffany

Gabe Tiffany
Acting State Oil and Gas Supervisor

Cc:
Courtney Smith
Emily Reader
Jeanette Hand
Lucy Redmond
[redacted]
Christine Cowsert