



Wild Goose Storage, LLC
A Rockpoint Gas Storage Company

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February 13, 2026

Terence Eng, P.E.
Program Manager
Gas Safety and Reliability Branch
Safety and Enforcement Division
California Public Utilities Commission
505 Van Ness Avenue, 2nd Floor
San Francisco, CA 94102-3298
terence.eng@cpuc.ca.gov

VIA ELECTRONIC MAIL

RE: General Order 112-F Inspection of Wild Goose Storage

Dear Mr. Eng:

Wild Goose Storage, LLC (WGS) submits this written response to the Safety and Enforcement Division (SED) of the California Public Utilities Commission (Commission). On behalf of the SED, Anthony Phu, Humna Afzel, Aleksandr Fastovich, and Andrea Garcia Ruvalcaba conducted a General Order 112-F inspection of WGS's Operations and Maintenance Plan, Operator Qualification Program, and Control Room Management Plan from November 3-7, 2025. The inspection findings identified by SED were provided to WGS on January 15, 2026. WGS addresses the inspection findings as noted by SED in the "Post-Inspection Written Findings" in the following enclosed document:

- **Attachment #1** – WGS Responses to "Post-Inspection Written Findings"
- **Attachment #2** – WGS Control Room Management Plan Appendix E-4 (SCADA Operations Manual) and an excerpt from WGS Control Room Management Plan Section 3.3 highlighting revisions to address point-to-point verification
- **Attachment #3** – Excerpt from WGS Operations and Maintenance Manual section 3.5 highlighting revisions to address remedial action plans
- **Attachment #4** – Excerpts from WGS Operations and Maintenance Manual section 3.5 and WGS Design and Construction Considerations highlighting revisions to address internal corrosion
- **Attachment #5** – Excerpt from WGS Control Room Management Plan section 2.2.2 highlighting revisions to address controller authority
- **Attachment #6** – Excerpt from WGS Control Room Management Plan section 6.1 highlighting revisions to address MOC participation of control room representatives
- **Attachment #7** – Excerpt from WGS Operations and Maintenance Manual section 2.0 highlighting revisions to address reporting of incidents
- **Attachment #8** – Excerpt from WGS Operations and Maintenance Manual section 3.5 highlighting revisions to address abnormal operating conditions

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

Sincerely,

Signed by:

5A3122A4501D4A7...

Gregory N. Clark
Senior Compliance Manager

Enclosures

cc: C. Almengor (claudia.almengor@cpuc.ca.gov)
D. Lee (dennis.lee@cpuc.ca.gov)
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A. Phu (anthony.phu@cpuc.ca.gov)
A. Anderson, S. Aycock, G. Bozarth, D. Carrion (via e-mail)

Attachment #1



WGS Responses to “Post-Inspection Written Findings”



WGS Responses to Post-Inspection Written Preliminary Findings

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

Operator: WILD GOOSE STORAGE LLC

Operator ID: 31287 (primary)

Inspection Systems: The entire transmission system

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

System Type: GT

Inspection Name: (2025) Wild Goose Storage TIMP Audit

Lead Inspector: Paul Penney

Operator Representative: Greg Clark, et all

Unsatisfactory Results

CRM, SCADA, and Leak Detection : Supervisory Control and Data Acquisition (CR.SCADA)

Unsat #1:

Question Title, ID Point-to-Point Verification Extent, CR.SCADA.POINTVERIFYEXTENT.P

Question **12. Are there adequate processes for the thoroughness of the point-to-point verification?**

References 192.631(c)(2)

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary CFR 192.631(c)(2) states in part:

"(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

...

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays"



Wild Goose Storage's Control Room Management Plan (CRMP) (plan version 10/09/2024)
Section 3.3 Point-To-Point Verification states:

"The WGS SCADA Operations Manual (Appendix E-4) contains the steps required for conducting a point-to-point verification. WGS follows an established MOC process when SCADA change procedures are initiated. Section 6.3 of this Plan describes the MOC process in detail."

At the time of inspection, WGS did not have a SCADA Operations Manual ('Appendix E-4') as referenced in their CRM plan; however, they noted that they are currently drafting the manual.

WGS did not have an implemented written process defining how point-to-point verification is conducted within the WGS CRM Plan. Therefore, SED finds WGS in violation of CFR 192.631(c)(2).

WGS Response WGS has updated its CRMP by revising Section 3.3 and completing the SCADA Operations Manual (Appendix E-4) to address point-to-point verification. Please see Attachment #2.

Unsat #2:

Question Title, ID Point-to-Point Verification Interval, CR.SCADA.POINTVERFIYINTVL.P

Question **14. Is there an adequate process for defining when the point-to-point verification must be completed?**

References 192.631(c)(2)

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary CFR 192.631(c)(2) states in part:

"(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

...

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays"

Wild Goose Storage's Control Room Management Plan (CRMP) (plan version 10/09/2024)
Section 3.3 Point-To-Point Verification states:

"The WGS SCADA Operations Manual (Appendix E-4) contains the steps required for conducting a point-to-point verification. WGS follows an established MOC process when SCADA change procedures are initiated. Section 6.3 of this Plan describes the MOC process in detail."

At the time of inspection, WGS did not have a SCADA Operations Manual ('Appendix E-4') as referenced in their CRM plan; however, they noted that they are currently drafting the manual.

WGS did not have an implemented written process defining the frequency that point-to-point verification is to be conducted within the WGS CRM Plan. Therefore, SED finds WGS in violation of CFR 192.631(c)(2).



WGS Response WGS has updated its CRMP by revising Section 3.3 and completing the SCADA Operations Manual (Appendix E-4) to address point-to-point verification. Please see Attachment #2.

Unsat #3:

Question Title, ID Backup SCADA Verification, CR.SCADA.BACKUPSCADAVERIFY.P

Question **23. Is testing required to verify adequate processes are in place for decision-making and internal communications to successfully implement a transition from primary SCADA to backup SCADA, and back to primary SCADA?**

References 192.631(c)(4)

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary CFR 192.631(c)(4) states in part:

"(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

...

(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months"

Wild Goose Storage's Control Room Management Plan (CRMP) (plan version 10/09/2024) Section 3.5 Backup Systems Testing states:

"WGS tests their Emergency Response activities and backup system annually (where applicable) in accordance with the WGS Emergency Response Plans and procedures and the WGS SCADA Operations Manual to ensure effectiveness and identify potential improvements."

At the time of inspection, WGS did not have a SCADA Operations Manual ('Appendix E-4') as referenced in their CRM plan; however, they noted that they are currently drafting the manual.

WGS did not have an implemented written process defining how backup SCADA operations and testing is conducted within the WGS CRM Plan. Therefore, SED finds WGS in violation of CFR 192.631(c)(4).

WGS Response WGS has updated its CRMP by completing the SCADA Operations Manual (Appendix E-4). Please see Attachment #2.

Unsat #4:

Question Title, ID Backup SCADA Transfer, CR.SCADA.BACKUPSCADATRANSFER.P

Question **26. Do processes adequately address and test the logistics of transferring control to a backup control room?**

References 192.631(c)(4)

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary CFR 192.631(c)(4) states in part:



"(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

....(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months"

Wild Goose Storage's Control Room Management Plan (CRMP) (plan version 10/09/2024) Section 3.5 Backup Systems Testing states:

"WGS tests their Emergency Response activities and backup system annually (where applicable) in accordance with the WGS Emergency Response Plans and procedures and the WGS SCADA Operations Manual to ensure effectiveness and identify potential improvements."

At the time of inspection, WGS did not have a SCADA Operations Manual ('Appendix E-4') as referenced in their CRM plan; however, they noted that they are currently drafting the manual.

WGS did not have a written process to adequately address and test the logistics of transferring control to a backup control room within the WGS CRM Plan. Therefore, SED finds WGS in violation of CFR 192.631(c)(4).

WGS Response WGS has updated its CRMP by completing the SCADA Operations Manual (Appendix E-4). Please see Attachment #2.

Unsat #5:

Question Title, ID Backup SCADA Return to Primary, CR.SCADA.BACKUPSCADARETURN.P

Question **27. Do procedures adequately address and test the logistics of returning operations back to the primary control room?**

References 192.631(c)(4)

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary CFR 192.631(c)(4) states in part:

"(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

...(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months"

Wild Goose Storage's Control Room Management Plan (CRMP) (plan version 10/09/2024) Section 3.5 Backup Systems Testing states:

"WGS tests their Emergency Response activities and backup system annually (where applicable) in accordance with the WGS Emergency Response Plans and procedures and the WGS SCADA Operations Manual to ensure effectiveness and identify potential improvements."



At the time of inspection, WGS did not have a SCADA Operations Manual ('Appendix E-4') as referenced in their CRM plan; however, they noted that they are currently drafting the manual.

WGS did not have a written process to adequately address and test the logistics of returning operations back to the primary control room within the WGS CRM Plan. Therefore, SED finds WGS in violation of CFR 192.631(c)(4).

WGS Response WGS has updated its CRMP by completing the SCADA Operations Manual (Appendix E-4). Please see Attachment #2.

Time-Dependent Threats : External Corrosion - CP Monitoring (TD.CPMONITOR)

Unsat #6:

Question Title, ID Extent of Corrosion Control Deficiencies for Onshore Gas Transmission, TD.CPMONITOR.DEFICIENCYEXTENT.P (also presented in: SP.CL-A-CP)

Question **12. For onshore gas transmission pipelines, does the process require that the operator develop a remedial action plan to determine the extent of the area affected when low cathodic protection levels are detected?**

References 192.605(b)(2) (192.465(d), 192.465(f))

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary CFR 192.465(d) states in part:

"(d) Each operator must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of this section. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits."

CFR 192.465(f) states in part:

"(f) An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this part."

SED reviewed the following sections of Wild Goose Storage's O&M Manual (dated October 2025):

- CATHODIC PROTECTION/EXTERNAL CORROSION CONTROL page 119, 120
- ELECTRICAL ISOLATION, Repairs on page 124
- IMPRESSED CURRENT POWER SOURCE – INSPECTION page 127

WGS did not have an adequate written process requiring that the operator develop a remedial action plan to determine the extent of the area affected when low cathodic



protection levels are detected. Therefore, SED finds WGS in violation of CFR 192.465(d) and 192.465(f).

WGS Response WGS has updated its O&M procedures section 3.5 to address remedial action plans with respect to cathodic protection levels. Please see Attachment #3.

Time-Dependent Threats : Internal Corrosion - Preventive Measures (TD.ICP)

Unsat #7:

Question Title, ID Corrosion Control Records, TD.ICP.DESIGN.P

Question **16. Does the process require new transmission pipelines or replacement segments to be designed to reduce the risk of internal corrosion?**

References 192.605(b)(2) (192.476(a), 192.476(b), 192.476(c))

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary CFR 192.476(a) states:

"(a) Design and construction. Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

- (1) Be configured to reduce the risk that liquids will collect in the line;
- (2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and
- (3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion."

SED reviewed Wild Goose Storage's O&M Manual (dated October 2025) and the WGS Design and Construction Considerations (DR24) and found that WGS did not have an adequate written process requiring new or replacement pipe to be designed to reduce the risk of internal corrosion. Therefore, SED finds WGS in violation of CFR 192.476(a).

WGS Response WGS has updated its O&M procedures section 3.5 and the WGS Design and Construction Considerations to address the risk of internal corrosion. Please see Attachment #4.



Concerns

CRM, SCADA, and Leak Detection : CRM Roles and Responsibilities (CR.CRMRR)

Concern #1:

Question Title, ID Roles and Responsibilities, CR.CRMRR.RESPONSIBLE.P

Question **1. Are there clear processes to describe each controller's physical domain of responsibility for pipelines and other facility assets?**

References 192.631(b)

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary WGS did not include CFR 192.631(b)(5) (effective 03/24/2017) into its CRMP updates. SED recommends WGS to update their procedure and integrate changes from Title 49 CFR 192.631(b).

WGS Response WGS has updated its CRMP Procedures section 2.2.2 to address controller authority. Please see Attachment #5.

CRM, SCADA, and Leak Detection : Change Management (CR.CRMCMGT)

Concern #2:

Question Title, ID Controller Participation in System Changes, CR.CRMCMGT.CONTROLLERPARTICIPATE.P

Question **2. Are control room representative(s) required to participate in meetings where changes that could directly or indirectly affect the hydraulic performance or configuration of the pipeline (including routine maintenance and repairs) are being considered, designed and implemented?**

References 192.631(f)(1) (192.631(f)(3))

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary SED reviewed Wild Goose Storage's Control Room Management Plan (CRMP) (plan version 10/09/2024) Section 6.3 WGS Management of Change Process and Integrity Management Plan (IMP) (plan version 10/24/24) Section 7.3.3.

WGS Integrity Management Plan (IMP) (plan version 10/24/24) Section 7.3.3 states in part:

"3) MOC Review Process



MOC Coordinator will coordinate the entire review process, including arranging review meetings with subject matter experts (if applicable)."

Wild Goose Storage's Control Room Management Plan (CRMP) and Integrity Management Plan (IMP) do not contain adequate processes to include control room representative(s) required to participate in meetings regarding changes that could directly or indirectly affect the hydraulic performance or configuration of the pipeline (including routine maintenance and repairs) are being considered, designed and implemented.

SED requests WGS to update their procedure to include control room representative(s) required to participate in meetings regarding changes that could directly or indirectly affect the hydraulic performance or configuration of the pipeline (including routine maintenance and repairs) are being considered, designed and implemented per CFR 192.631.

WGS Response WGS has updated its CRMP Procedures Section 6.1 to address MOC participation of control room representatives. Please see Attachment #6.

Reporting : Regulatory Reporting (Traditional) (RPT.RR)

Concern #3:

Question Title, ID Immediate Reporting: Incidents, RPT.RR.IMMEDREPORT.P

Question **3. Is there a process to immediately report incidents to the National Response Center?**

References 191.5(b) (191.7, 191.1(a), 192.8(c)(3))

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary SED reviewed Wild Goose Storage's O&M Manual (dated October 2025), Section 2.0 - Normal Operations and found the following hyperlinks were not working:

- Section 2.1 Pipeline Reporting, Subsection CPUC Incident Reports PHMSA F7100.1 (<http://ops.dot.gov/library/forms/forms.htm#7100.1>) page 23
- Section 2.2 Incidents - Reporting and Control, Subsections GENERAL - D.O.T. / PHMSA Reporting (<http://pipelineonlinereporting.phmsa.dot.gov/>) page 30

SED requests WGS repair the above hyperlinks so that operator personnel may reference the listed materials or provide other directions on how to access the referenced materials.

WGS Response WGS has updated its O&M Procedures section 2.0 to address reporting of incidents. Please see Attachment #7.

Time-Dependent Threats : Atmospheric Corrosion (TD.ATM)

Concern #4:

Question Title, ID Atmospheric Corrosion Monitoring, TD.ATM.ATMCORRODEINSP.P

Question **3. Does the process give adequate instruction for the inspection of aboveground pipeline segments for atmospheric corrosion?**



References 192.605(b)(2) (192.481(a), 192.481(b), 192.481(c), 192.481(d), 192.9(f)(1), 192.453)

Assets Covered Wild Goose Storage (88673 (36))

Issue Summary SED reviewed Wild Goose Storage's O&M Manual (dated October 2025) Section 3.5 Corrosion Control, ATMOSPHERIC CORROSION on page 104.

The text describing abnormal operating conditions (AOCs) includes two examples that are not AOCs:

- Coating is in good condition with no evidence of disbondment or corrosion.
- Normal surface rust arises on uncoated piping that can be cleaned and painted.

SED requests that WGS review its list of AOCs to ensure that all the listed examples are relevant.

WGS Response WGS has updated its O&M Procedures section 3.5 to address abnormal operating conditions. Please see Attachment #8.

Attachment #2



**WGS Control Room Management Plan Appendix E-4 (SCADA Operations Manual)
and an excerpt from WGS Control Room Management Plan Section 3.3
highlighting revisions to address point-to-point verification**

 Wild Goose Storage, LLC A ROCKPOINT GAS STORAGE COMPANY	APPENDIX E-4 WILD GOOSE STORAGE, LLC SCADA OPERATIONS MANUAL	PROJECT: WGS-001 REV.: 0 DATE: 01/26/26 PAGE: 1
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1.0 GENERAL

The purpose of this procedure is to ensure that qualified persons have taken the appropriate measures to safely and effectively calibrate field devices and instruments. These devices include but are not limited to Discrete Switches (dry-contacts), Pressure Transmitters, Temperature Transmitters and Resistance Temperature Detectors (RTD's).

2.0 POINT-TO-POINT CHECKS & CALIBRATIONS

2.1 PREPARATION

Before performing any point-to-point check or device calibration, the person(s) responsible for the device calibrations must perform the following:

1. Notify Operations Manager and Controller of devices to be calibrated (i.e. site location, devices, time, etc.).
2. Communications between the calibration technician(s) and Controller must be maintained before, during and after the calibration process to ensure the device(s) is/are functioning properly and placed back in normal, operational service.
3. Ensure proper Personal Protection Equipment (PPE) is worn and a safe work environment exists prior to accessing the device: **No Gas Present or Below LEL.**

2.2 SCADA SYSTEM

Prior to physically calibrating a device, the device must be put in bypass mode on the SCADA system to hold the last known acceptable value. This can be done remotely while communicating with the controller or locally via an access node or a laptop connected to the SCADA network. Due to the safety/operations interlock logic, the last known "good" value will be maintained while in Bypass Mode to avoid adverse reactions during the calibration process until the device is returned to its normal, operational state. (For a point-to-point check, the device should be placed in bypass mode and verify the device is checked completely to each point on the HMI where it is displayed.

For point-to-point verification the Controller will verify output points with person doing the calibrations to make sure each point matches with device & SCADA.

 Wild Goose Storage, LLC A ROCKPOINT GAS STORAGE COMPANY	APPENDIX E-4 WILD GOOSE STORAGE, LLC SCADA OPERATIONS MANUAL	PROJECT: WGS-001 REV.: 0 DATE: 01/26/26 PAGE: 2
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2.3 DEVICES / INSTRUMENTS

2.3.1 Pressure Transmitters

- Pressure Transmitters
- Pressure Indicating Transmitters

2.3.2 Differential Pressure Transmitters

- Differential Pressure Transmitters

2.3.3 Temperature Transmitters

- Temperature Transmitters
- Temperature Indicating Transmitters
- RTD's

2.3.4 Discrete Switches (Dry Contacts)

- Level Switches
- Vibration Switches
- Valve Position
- Vibration Sensor
- Flow Switches

 Wild Goose Storage, LLC A ROCKPOINT GAS STORAGE COMPANY	APPENDIX E-4 WILD GOOSE STORAGE, LLC SCADA OPERATIONS MANUAL	PROJECT: WGS-001 REV.: 0 DATE: 01/26/26 PAGE: 3
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2.3.1 PRESSURE TRANSMITTER

Step	Action	Comments
1.	Ensure transmitter is in calibrate or maintenance mode before performing calibration, as required.	Contact controller or view on local node. See Section 2.2 SCADA System.
2.	Remove transmitter cover and connect HART communication device to transmitter (+/-). Verify Tag ID, range and units	See Section 2.1.3
3.	Isolate transmitter by closing isolation valve(s) (process connection) on valve manifold.	May be necessary to close the valve upstream if leaks persist.
4.	Relieve pressure on valve manifold by slowly opening vent valve to atmosphere. Remove cap if installed prior to venting.	Potential for injury – ensure proper PPE is worn.
5.	Connect calibration pressure source (N ₂ or other, inert dry gas) with a <u>Calibrated Pressure Gauge</u> in line to the vent valve and tighten. Maintain closed position on process connection valve for isolation from line pressure.	Pressure Gauge must be calibrated annually by a certified NIST lab. Tighten fitting with appropriate tools.
6.	Check Zero reading on device, calibrated pressure gauge, HART communicator and SCADA and record data. Tolerance = 0.25% of device range. Use a Fluke 789 or similar process MA reading to verify MA reading.	If SCADA ≠ devices, enter off-set for D/A trim (4mA) and re-evaluate. If difference is > 0.25% between devices, re-zero device, set sensor lower trim and re-evaluate.
7.	Apply pressure slowly from source	Rapid over pressurization could damage transducer.
8.	Calibrate transmitter at 25%, 50%, 75% and 100% of full range and record data. Tolerance = 0.25% of device range.	If SCADA ≠ devices, enter off-set at full scale for D/A trim (20mA) and re-evaluate. If difference is > 0.25% between devices, set sensor upper trim and re-evaluate.
9.	For point-to-point checks, verify each instrument change on HMI and Historian.	

 Wild Goose Storage, LLC A ROCKPOINT GAS STORAGE COMPANY	APPENDIX E-4 WILD GOOSE STORAGE, LLC SCADA OPERATIONS MANUAL	PROJECT: WGS-001 REV.: 0 DATE: 01/26/26 PAGE: 4
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2.3.1 PRESSURE TRANSMITTER

Step	Action	Comments
If transmitter does not satisfy the above tolerance, it must be taken out of service and replaced with a calibrated equivalent.		
10.	Turn off calibration pressure source, bleed the line and disconnect source.	
11.	Close vent valve on manifold body and replace transmitter cover and vent cap(s)	Tighten cap fitting with appropriate tools.
12.	Open isolation valve(s) slowly on manifold and check for leaks.	
13.	Disable Bypass Mode in SCADA and verify local and SCADA “live” data values are within tolerance limits.	Ensure the values displayed are not the “last known values” while in Bypass Mode.

2.3.2 DIFFERENTIAL TRANSMITTER

Step	Action	Comments
1.	For point-to-point checks, verify each instrument change on HMI and Historian.	
If transmitter does not satisfy the above tolerance, it must be taken out of service and replaced with a calibrated equivalent.		
2.	Turn off calibration pressure source, bleed the line and disconnect source.	
3.	Close vent valve on manifold body and replace transmitter cover and vent cap(s). Open EQ valve.	Tighten cap fittings with appropriate tools.
4.	Open isolation valve(s) slowly on manifold and check for leaks. Close EQ valve once fully pressurized.	Closing EQ valve after pressurizing prevents damage to transmitter.
5.	Disable Bypass Mode in SCADA and verify local and SCADA “live” data values are within tolerance limits.	Ensure the values displayed are not the “last known values” while in Bypass Mode.

 Wild Goose Storage, LLC A ROCKPOINT GAS STORAGE COMPANY	APPENDIX E-4 WILD GOOSE STORAGE, LLC SCADA OPERATIONS MANUAL	PROJECT: WGS-001 REV.: 0 DATE: 01/26/26 PAGE: 5
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2.3.3 TEMPERATURE TRANSMITTER

Step	Action	Comments
1.	Ensure transmitter is in calibrate or Bypass Mode before performing calibration.	Contact Controller or view on local node. See Section 2.2 SCADA System.
2.	Remove transmitter cover and connect HART communication device to transmitter (+/-). Verify Tag ID, range and units. If HART communicator is not used, use a Fluke temperature calibrator or similar to verify temperatures.	See Section 2.1.3
3.	See attached page for temperature calibration procedures.	Thermometer must be calibrated annually by a certified NIST lab. If Dry Block Calibrator is used, it must also be calibrated annually by a certified NIST lab
4.	Calibrate transmitter at 25%, 50%, 75% and 100% of full range and record data. <u>If dry block calibrator is not available, evaluate at ambient and ice-point conditions.</u> Tolerance = 0.25% of device range.	If SCADA does not equal devices, enter off-set for D/A trim and re-evaluate. If difference is > 0.25% between devices, re-trim sensor.
If transmitter does not satisfy the above tolerance, replace RTD. If the tolerance is still not satisfied, the transmitter must be taken out of service and replaced with a calibrated equivalent.		
5.	Replace transmitter cover if TIT.	Tighten fitting with appropriate tools.
6.	Disable Bypass Mode in SCADA and verify local and SCADA “live” data values are within tolerance limits.	Ensure the values displayed are not the “last known values” while in Cal Mode.
7.	For point-to-point checks, verify each instrument change on HMI and Historian.	

 Wild Goose Storage, LLC A ROCKPOINT GAS STORAGE COMPANY	APPENDIX E-4 WILD GOOSE STORAGE, LLC SCADA OPERATIONS MANUAL	PROJECT: WGS-001 REV.: 0 DATE: 01/26/26 PAGE: 6
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2.3.4 DISCRETE SWITCHES – DRY CONTACTS (NO OR NC)		
Step	Action	Comments
1.	Ensure device is in calibrate or maintenance mode before performing calibration. If unable to put in Cal Mode, then stay in contact with controller during calibration.	Contact controller or view on local node. See Section 2.2 SCADA System.
2.	Gain access to position switch.	See Section 2.1.3
3.	Confirm switch indicates the correct position (i.e. liquid level L, LL, H, HH, valve position, metal detection, vibration, etc.) prior to calibration.	If incorrect, reposition switch and look for change of state
4.	Manually trigger the switch. Use a magnet or other method to change contact state.	Confirm switch position changed state - call controller or view on local node
5.	Reset switch to original position	Confirm switch returned to its original state - call controller or view on local node
6.	For point-to-point checks, verify each instrument change on HMI and Historian.	
If the switch fails to indicate change of state (NO → Closed or NC → Opened) then it must be taken out of service and replaced.		
7.	Disable Bypass Mode in SCADA and verify local and SCADA “live” data values.	Ensure the values displayed are not the “last known values” while in Cal Mode.

3.0 REDUNDANT SYSTEMS TESTING

3.1 SCADA SYSTEM BRIEF DESCRIPTION

This system uses a central redundant pair of SCADA hosts that communicate with all of the plants, pipeline and wells PLCs for monitoring, control, alarming, and historical data collection.

The environment includes a primary network through which process control information is transmitted. An active partner of a fail-over host pair operates on a first machine communicatively

 Wild Goose Storage, LLC A ROCKPOINT GAS STORAGE COMPANY	APPENDIX E-4 WILD GOOSE STORAGE, LLC SCADA OPERATIONS MANUAL	PROJECT: WGS-001 REV.: 0 DATE: 01/26/26 PAGE: 7
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connected to the primary network, and the active partner hosts a set of executing application components. A standby partner of the fail-over host pair operates on a second machine communicatively connected to the primary network. The standby partner receives updates including engine synchronization data associated with the set of executing application components to facilitate taking over an active partner role in response to a fail-over event. The environment also includes a redundancy message channel, separate and distinct from the primary network. The redundancy message channel provides a communications path between the first machine and second machine facilitating passing the updates including engine synchronization data.

3.2 IDENTIFIED LAYERS OF REDUNDANCY

1. Server Hardware

SCADA servers allow single drive failure and hot swapping

A direct link on each server allows fault tolerance and hot swapping. Most common server fault is power supply failure.

A UPS is incorporated to the Power Distribution System.

2. Server Topology and Software

The hardware topology required for redundant-node functionality is simple: two computers, each with two network interface cards (NIC). The first network card is for the supervisory network; the second card is for the Redundancy Message Channel (RMC). There are also several attributes that allow manual failover at any time, also within a script if needed. If server redundancy is supported, describe how changes to the off-line server's real-time database are copied to the on-line server.

Wonderware System Platform is the software that provides management of redundancy for:

- I/O Servers (communication to the PLCs)
- Alarm Servers (alarms are global, only have to be acknowledged in one place)
- Historical Trending of Process Data
- Historical Trending of Alarm and Event data

3.3 REDUNDANCY VERIFICATION TEST PROCEDURES

Test redundant SCADA systems at least once each calendar year, but at intervals not to exceed 15 months.

1. Test 1 – Communication Redundancy Server 2 (Secondary SCADA server)

- a. Verify all Platform Processes are “Active” on Server 1 Primary Server & Server 2 Secondary Server is on “Standby”
- b. Disconnect Primary SCADA Server 1 from network so it cannot communicate with PLCs or SCADA clients.
- c. Verify Process Points are updating

 Wild Goose Storage, LLC A ROCKPOINT GAS STORAGE COMPANY	APPENDIX E-4 WILD GOOSE STORAGE, LLC SCADA OPERATIONS MANUAL	PROJECT: WGS-001 REV.: 0 DATE: 01/26/26 PAGE: 8
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- d. Verify Trend Data is accessible
 - e. Verify Alarm Log is accessible
 - f. Place system in “Unattended Mode” & generate a “Page Operator Alarm”
 - g. Verify Page received from Secondary Callout Server notifying of Server failure & Page Operator Alarm
 - h. Acknowledge alarm from client
 - i. Reconnect Primary SCADA Server 1
 - j. Verify Process Points are updating
 - k. Verify Trend Data is accessible
 - l. Verify Alarm Log is accessible
2. Test 2 – Communication Redundancy Server 1 (Primary SCADA server)
- a. Verify all Platform Processes are “Active” on Server 2 Secondary Server & Server 1 Secondary Server is on “Standby”
 - b. Disconnect Secondary SCADA Server 2 from network so it cannot communicate with PLCs or SCADA clients.
 - c. Verify Process Points are updating
 - d. Verify Trend Data is accessible
 - e. Verify Alarm Log is accessible
 - f. Place system in “Unattended Mode” & generate a “Page Operator Alarm”
 - g. Verify Page received from Secondary Callout Server notifying of Server failure & Page Operator Alarm
 - h. Acknowledge alarm from client
 - i. Reconnect Primary SCADA Server 2
 - j. Verify Process Points are updating
 - k. Verify Trend Data is accessible
 - l. Verify Alarm Log is accessible



Wild Goose Storage, LLC

Control Room Management Plan

Satisfies 192.631

Plan Version: December 5, 2025

3. Adequate Information

3.1. Rule Requirements

In accordance with the Rule requirements, WGS provides Controllers with the information, tools, processes, and procedures necessary for the Controllers to carry out the roles and responsibilities the operator has defined, to include the following:

- Implementing API RP 1165 whenever a SCADA system is added, expanded, or replaced, unless the operator demonstrates that certain provisions of API RP are not practical for the SCADA system used.
- Conducting a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays.
- Testing and verifying an internal communication plan to provide adequate means for manual operation of the pipeline safely at least once each calendar year but not to exceed 15 months.
- Testing any backup SCADA system at least once each calendar year but not to exceed 15 months.
- Implementing Section 5 of API RP 1168 to establish procedures for when a different Controller assumes responsibility, including the content of information to be exchanged.

All records associated with the above requirements are retained for 5 years in a secured server location.

3.2. API RP 1165 Implementation

Appendix E provides the procedures for implementing the required sections of API RP 1165 when adding a new SCADA system or making changes to replacing a system, to include the following:

- Human Factors Engineering Considerations in Display Design, to include short-term memory, signal-to-noise ratio, eye scan pattern, consistency, and coding
- Display hardware and devices, display response, input devices
- Display layout and organization, number of monitors and window spanning
- Display navigation
- Object characteristics, labels, messages, and object dynamics
- Control and Selection Techniques, command execution, error management, administration, and standardization
- Documentation and Management of Change (MOC)
- Maintenance and Testing
- Release Management

3.3. Point-To-Point Verification

WGS conducts point-to-point verification between the SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays. The WGS SCADA Operations Manual (Appendix E-4) contains the steps required for conducting a point-to-point verification. WGS follows an established MOC process when SCADA change procedures are initiated. Section 6.3 of this Plan describes the MOC process in detail.

Attachment #3



**Excerpt from WGS Operations and Maintenance Manual section 3.5
highlighting revisions to address remedial action plans**

- A negative polarized (current switched off) potential of at least 0.85 volt relative to a saturated copper-copper sulfate reference electrode.
- A minimum of 100 mV of cathodic polarization. The formation of decay of polarization can be used to satisfy criterion.
- A negative (cathodic) potential of at least 850 mV with the cathodic protection applied. This potential is measured with respect to a saturated Cu/CuSO₄ reference electrode containing the electrolyte. Voltage drops other than those across the structure to electrolyte boundary must be considered for valid interpretation of this voltage measurement (see NACE RP0169-2002) without current interruption.

Special Conditions

- In some situations, such as the presence of sulfides, bacteria, elevated temperature, acid environments and dissimilar metals, the criteria in the D.O.T. acceptable criteria section above may not be sufficient protection.

At pipeline locations where external corrosion-related leaks are discovered, a measurement of the pipe-to-soil cathodic potential shall be taken. If the level is less than that required by regulations, the Superintendent, U.S. Operations shall reevaluate the CP system capacity and upgrade it as necessary prior to the next inspection.

Test and survey of CP systems according to the frequency schedule listed in Table 3.5A.

Prompt remedial action must be taken to correct conditions which cause the pipeline to fail to meet the applicable criterion. A remedial action plan shall be developed, and any necessary permits shall be applied for within 6 months of completing the inspection or testing that identified the deficiency.

Remedial action must be completed no later than the earliest of the following:

- Prior to the next inspection or test interval required by this section;
- Within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or
- As soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

RECORDS: Record the location of cathodically protected pipeline, cathodic protection facilities, and neighboring structures bonded to cathodic protection system on **WGS Form 113 Cathodic Protection System Record** or, in the case that the work is performed by a contractor, on a mutually agreed upon document. (See pipeline drawings.)

Attachment #4



**Excerpts from WGS Operations and Maintenance Manual section 3.5
and WGS Design and Construction Considerations
highlighting revisions to address internal corrosion**

This procedure is required to ensure no corrosive gas flows through or remain in the WGS pipeline system. In the event corrosive gas is ever allowed to flow through or remain in the WGS pipeline system, this procedure will establish guidelines to remedy the situation.

A pipeline system includes all pipeline facilities used in the transportation of gas, including, but not limited to, gathering lines, line pipe, valves and other appurtenances connected to line pipe, fabricated assemblies, and metering stations.

Potential corrosive gas shall not be transported without monitoring equipment that will detect the presence of internal corrosion. In the event corrosive gas is being transported, coupons or other suitable means shall be used to determine the effectiveness of the steps taken to minimize internal corrosion.

If repair, replacement or operating pressure reduction is necessary, review Section 2.17, Safety Related Conditions Reporting, to see if a reportable safety related condition exists. Each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

- (1) Be configured to reduce the risk that liquids will collect in the line;
- (2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and
- (3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

Corrosive Conditions:

Gas containing water in liquid phase and at least one of the following components is considered to be potentially corrosive. A combination of two or more components is considered to be potentially corrosive. A combination of two or more components with water in liquid phase may be potentially corrosive at lower concentrations of each component. Gas having a water vapor below the point of saturation may contain concentrations of H₂S and CO₂ and O₂ greater than those listed below and remain non-corrosive.

- Hydrogen sulfide (H₂S) concentration greater than .05 psia partial pressure for systems operating at or above 65 psia total pressure. For system pressure less than 65 psia total pressure, H₂S content of 50 ppm or greater is considered corrosive.



	the pipeline into the ditch, padding and backfilling, and hydrostatic testing.
	(2) The quality assurance plan for applying and testing field applied coating to girth welds must be:
	(i) Equivalent to that required under §192.112(f)(3) for pipe; and
	(ii) Performed by an individual with the knowledge, skills, and ability to assure effective coating application.
(b) Girth welds	(1) All girth welds on a new pipeline segment must be non-destructively examined in accordance with §192.243(b) and (c).
(c) Depth of cover	(1) Notwithstanding any lesser depth of cover otherwise allowed in §192.327, there must be at least 36 inches (914 millimeters) of cover or equivalent means to protect the pipeline from outside force damage.
	(2) In areas where deep tilling or other activities could threaten the pipeline, the top of the pipeline must be installed at least one foot below the deepest expected penetration of the soil.
(d) Initial strength testing	(1) The pipeline segment must not have experienced failures indicative of systemic material defects during strength testing, including initial hydrostatic testing. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic concern. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipe is in service at least 60 days prior to operating at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
(e) Interference currents	(1) For a new pipeline segment, the construction must address the impacts of induced alternating current from parallel electric transmission lines and other known sources of potential interference with corrosion control.

- 6.12** Each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:
- (1) Be configured to reduce the risk that liquids will collect in the line;
 - (2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and
 - (3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

Attachment #5



**Excerpt from WGS Control Room Management Plan section 2.2.2
highlighting revisions to address controller authority**

2. Roles and Responsibilities

2.2. WGS Controller Roles and Responsibilities**2.2.1. General Description**

The primary role of the Control Center is to remotely monitor and control the safe and efficient transportation of scheduled nominations through the pipeline system on behalf of the shippers.

Controllers monitor for the following:

- Pipeline Integrity
- Pressures
- Temperatures
- Flows

Control Center personnel monitor and control the pipeline system by using a SCADA system for gathering and analyzing real time data from meter stations.

2.2.2. Controller Authority

Controllers, qualified under WGS's Operator Qualification (OQ) requirements, have full authority, and are responsible for all monitoring, control, and operation of WGS's pipeline systems. If a Controller decides that conditions are unsafe to continue operation of the pipeline(s), they are authorized to take any necessary measures to ensure the safety of the facility, equipment, personnel, and the public without prior permission. **Note: others do not have the authority to direct or supersede the specific technical actions of the WGS Controller.**

In an emergency, a qualified Controller can shut down the pipeline.

Prior to resuming operations, communication between field personnel and the Control Center must be established. Once the field personnel and Controllers have communicated to each other and verified that operations can resume, the pipeline(s) can be restarted.

2.2.3. Controller Roles and Responsibilities

WGS Controllers are responsible for many ongoing, overlapping duties related to the efficient operation of one or more pipeline systems. Many of these duties are unique to the system and depend on changing operational conditions along the entire length of the pipeline. System-specific responsibilities are documented in the O&M Manual located via electronic media at the console and provided via WGS's SharePoint site. Controllers log in to SCADA using a unique ID.

2.2.3.1. All Controllers

WGS Controllers are responsible for the following:

- 1) Monitoring leak detection systems and responding to abnormal operating conditions (AOCs) and/or abnormal operating events (AOEs).
- 2) Monitoring equipment.
- 3) Evaluating pipeline status for abnormal conditions and responding as necessary.
- 4) Monitoring Remote Quality Control equipment and reacting to and reporting off-spec product anomalies.
- 5) Reviewing pipeline events and product characteristics (including recording) that may include information such as equipment status during events, pressures, temperatures, flows, and quality in conjunction with field personnel.
- 6) Controlling pipeline segments to protect them from exceeding authorized pressures.

Attachment #6



**Excerpt from WGS Control Room Management Plan section 6.1
highlighting revisions to address MOC participation
of control room representatives**

- Alarm Audit

The software application used to support the Alarm Management Program is Historian. The WGS Alarm Management Program will be reviewed annually, not to exceed 15 months, by the Alarm Management Team to address on-going program activities.

The Alarm Management Team can include, but is not limited to, the following:

- Lead Operator
- Operations Manager
- Controller
- SCADA Representative
- WGS Work Team Representative
- Senior Compliance Manager
- Superintendent, U.S. Operations

5.3. Workload Analysis

WGS investigated several methods for conducting a thorough workload analysis. WGS hired a third-party specialist to develop the baseline acceptable workload levels for their Controllers and provide recommended actions for future task assessment (Appendix J-1). Using this third-party analysis as the baseline, WGS will complete an internal review of alarm data and console/facility tasks each calendar year not to exceed 15 months to determine the increase and/or decrease in workload to ensure Controller performance meets the minimum performance standards in accordance with the WGS Workload Analysis Form (Appendix J-2).

6. Change Management

6.1. Rule Requirements

In accordance with the Rule requirements, WGS assures that changes potentially affecting the Control Center operations are coordinated with Control Center personnel, to include the following:

- Implementing Section 7 of API RP 1168 for Control Center management change, to include coordination among Control Center representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration
- Requiring field personnel to contact the Control Center when emergency conditions exist and when making field changes that affect Control Center operations
- Seeking control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

All records associated with the above requirements are retained for 5 years in a secured server location.

6.2. API RP 1168 Requirements

Section 7 of API RP 1168 requires the following:

- Inclusion of Pipeline Control Center Personnel

Change must be managed and governed by effective processes and procedures. For MOC to be effective, affected personnel should be a part of the decision and implementation process.

Attachment #7



**Excerpt from WGS Operations and Maintenance Manual section 2.0
highlighting revisions to address reporting of incidents**

SECTION 2.0 – NORMAL OPERATIONS

2.1 Pipeline Reporting

PURPOSE: The purpose of this procedure is to establish responsibilities for preparing and submitting of pipeline reports.

SCOPE/APPLICABILITY:

The Senior Compliance Manager, and/or their designate, is responsible for communicating information and data to State and Federal agencies regarding pipeline annual reports of transmission and gathering pipeline facilities (**DOT Form PHMSA F 7100.2.1**).

The G.O. 112-F report is to be prepared by the Senior Compliance Manager, and/or their designate, and submitted to the CPUC no later than March 15 of each year for the preceding calendar year.

PROCEDURE:

Responsibility/Authority: The Senior Compliance Manager shall ensure annual reports are delivered to the applicable State and Federal agencies.

The procedure for submitting the report shall include collecting data, such as number and kind of leaks, cause of the leaks, their disposition, etc., for preparation and submitting of the annual pipeline report.

The following regulated lines should be included in the report:

- Gas transmission lines, distribution lines, branch lines, sales lines, and associated facilities, such as compressor stations, meter stations, regulator stations, etc.
- Onshore gas gathering lines in an area within the limits of any incorporated or unincorporated city, town or village and any distributed residential or commercial area such as a subdivision business or shopping center, or community development.
- Underground natural gas storage facility: WGS shall submit an annual report on DOT PHMSA Form 7100.4–1 by March 15, for the preceding calendar year except for the first report, which must be submitted by July 18, 2017.

Online submission via PHMSA Portal is required unless an alternative reporting method is granted by PHMSA. The completed form must be submitted no later than March 15 of each year for the preceding calendar year.

Incident and annual reports for intrastate pipeline transportation subject to the jurisdiction of a State agency pursuant to a certification under section 5(a) of the Natural Gas Pipeline Safety Act of 1968 may be submitted in duplicate to that State agency if the regulations

of that agency require submission of these reports and provide for further transmittal of one copy within 10 days of receipt for incident reports and not later than March 15 for annual reports to the Information Resources Manager.

If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the:

Information Resources Manager,
Office of Pipeline Safety,
Pipeline and Hazardous Materials Safety Administration,
PHP-20, 1200 New Jersey Avenue,
SE Washington DC 20590.

The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received. Operators should request and receive authorization from PHMSA prior to the use of alternative reporting methods.

A copy of the report shall also be sent to the CPUC.

CPUC Written Incident Reports:

WGS shall submit to DOT a written report on any safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility or a condition that is a hazard to life, property or the environment.

WGS shall submit to the CPUC on DOT Form PHMSA F7100.1 for distribution systems and on DOT Form PHMSA F7100.2 for transmission and gathering systems a report describing any incident that requires notice as described in the Incident Criteria below (<https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions>). WGS shall submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5.

Together with the form required above, WGS shall furnish a letter of explanation giving a more detailed account of the incident unless such letter is deemed not necessary by the CPUC staff. WGS may confirm the necessity of a letter of explanation while making the telephonic report. If, subsequent to the initial report or letter, WGS discovers significant additional information related to the incident, WGS shall furnish a supplemental report to the CPUC as soon as practicable, with a clear reference by date and subject to the original report. These letters, forms, and reports shall be held confidential under the provisions of Paragraph 2, Exclusions, of General Order 66 C and Public Utilities Code Section 315.

An operator of a distribution system serving less than 100,000 customers need not submit the DOT forms required by paragraph (1) above; however, WGS must submit the letter of explanation required by (2) above, subsequent to any telephonic report to the CPUC, unless such letter is deemed unnecessary by the CPUC staff.

National Pipeline Mapping System (NPMS) (Section 191.29)

WGS must supply the following geospatial data (described in the paragraph below) to PHMSA for pipelines or facilities, unless no changes have occurred since the prior year's report. If no changes have occurred, then WGS must comply with the guidance provided in the NPMS Operator Standards manual available at www.npms.phmsa.dot.gov or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.

Required Geospatial Data:

Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

Quarterly Summary Reports

SCOPE/APPLICABILITY:

The Senior Compliance Manager is responsible and/or their designate for producing Quarterly Summary Reports to the CPUC. The Quarterly Summary Report is a summary of all reportable and non-reportable incidents that happened in the preceding quarter. The report must be submitted to the CPUC no later than the following month of the end of the quarter.

A summary of all CPUC reportable and non-reportable incidents which occurred in the preceding quarter as follows:

1. Incidents that were reported through the Commission's Emergency Reporting website.
2. Incidents for which either a **DOT Form PHMSA F7100.1 or F7100.2** was submitted.
3. Incidents which involved escaping gas from the utility's facilities and property damage including loss of gas in excess of \$1,000.
4. Incidents which included property damage between \$0 and \$1,000, and involved fire, explosion, or excavation related damage.
5. Incidents where the failure of a pressure relieving and limiting stations, or any other unplanned event, results in pipeline system pressure exceeding its established Maximum

Allowable Operating Pressure (MAOP) plus the allowable build up set forth in 49 CFR § 192.201.

6. Incidents in which an under-pressure condition, caused by the failure of any pressure controlling device, or any other unplanned event other than excavation related damage, results in any part of the gas pipeline system losing service or being shut-down.

California Public Utilities Commission

Commission's Docket Office

505 Van Ness Avenue
San Francisco, California 94102
415.703.2782

800.848.5580 (Toll Free)

415.703.1758 Fax

PROCEDURE:

Responsibility/Authority:

The Compliance Manager shall ensure and produce the GO-112F Quarterly Summary Report to the CPUC no later than one month after the quarter has ended.

Proposed Installation Reports

This section applies to the construction of a new pipeline, or the reconstruction or reconditioning of an existing pipeline. In addition to the requirements of this section, copies of all reports submitted to the DOT pursuant to the requirements of 49 CFR, Part 191, §191.22(c)(1) shall be submitted to the CPUC at the same time.

“Construction of a new pipeline” means the installation of pipeline that will serve as a loop or extension to an existing pipeline or as an independent or stand-alone pipeline, any of which will be placed in service for the first time by a utility who filed a Form PHMSA F-7100.1-1 for the calendar year preceding the year in which construction takes place.

"Reconstruction of an existing pipeline" means the installation of pipeline that will replace an existing pipeline or pipeline segment due to alignment interference, deteriorating or aging conditions, pressure/capacity enhancement, or other reason.

"Reconditioning of an existing pipeline" is defined as the work associated with repairing, structurally reinforcing, the replacement of fittings or short segments of pipe, or for the removal and reapplication of pipe coating.

At least 60 days prior to the construction of a new pipeline, reconstruction, or reconditioning of an existing pipeline, a report shall be filed with the CPUC setting forth

the proposed route and general specifications for such pipeline. The specifications shall include but not be limited to the following items:

- a) Description and purpose of the proposed pipeline.
- b) Specifications covering the pipe selected for installation, route map segregating incorporated areas, class locations and design factors, terrain profile sketches indicating maximum and minimum elevations for each test section of pipeline, and, when applicable, reasons for use of casing or bridging where the minimum cover will be less than specified in §192.327.
- c) Maximum allowable operating pressure for which the line is being constructed.
- d) Test medium and pressure to be used during strength testing.
 - a. During strength testing of a pipeline to be operated at hoop stresses of 20 percent or more of the specified minimum yield strength of the pipe used, any failure shall be reported on appropriate forms to the CPUC.
- e) Protection of pipeline from hazards as indicated in §192.317 and §192.319.
- f) Protection of pipeline from external corrosion.
- g) Estimated cost with supporting detail.

Unless otherwise specified, if the notification is made pursuant to § 192.8(b)(2), § 192.9(g)(4)(ii) and (h), § 192.461(g), § 192.506(b), § 192.607(e)(4) and (5), § 192.619(c)(2), § 192.624(c)(2)(iii) and (c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv) and (e)(2)(i)(E), § 192.921(a)(7), § 192.927(b), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (i.e., “other technology”) that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. Affected personnel should be properly trained in the use of the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

Emergency Exception

In cases of projects necessary on an emergency basis, the required report shall be filed with the CPUC as far in advance of the project as practicable, but no later than 5 business days after the project has been initiated. Reports filed for emergency projects must also detail reasons that necessitated the project being performed on an emergency basis.

Required Notifications to PHMSA for Certain Events

PROCEDURE:

Responsibility/Authority:

The Senior Compliance Manager shall ensure and produce notifications to PHMSA electronically through the National Registry of Pipeline, Underground Natural Gas

Operations and Maintenance Procedures Manual
Gas Pipeline

Storage Facility, and LNG Operators via the PHMSA Portal at <http://opsweb.phmsa.dot.gov>.

PHMSA must be notified of certain events or changes according to section 191.22 (c) (1) and 191.22 (c) (2):

Applicability: gas pipeline operators, gas pipeline facility operators, underground natural gas storage facility operators, and LNG plant/facilities.

Reporting: Use the OPID issued by PHMSA for all reporting requirements and for submissions to the National Pipeline Mapping System.

Events that require PHMSA notification AT LEAST 60 Days BEFORE the Event:

1. Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs \$10 million or more. If 60 day notice is not feasible because of an emergency, the Senior Compliance Manager must notify PHMSA as soon as practicable
2. Construction of 10 or more miles of a new or replacement pipeline;
3. Construction of a new LNG plant or LNG facility; or
4. Construction of a new underground natural gas storage facility or the maintenance of an underground natural gas storage facility that involves the plugging or abandonment of a well, or that requires a workover rig and costs \$200,000 or more for an individual well (e.g., drilling or well workover, including replacement of wellhead, tubing, or a new casing, of an injection, withdrawal, monitoring, or observation well).
5. Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or
6. A pipeline converted for service under §192.14, or a change in commodity as reported on the annual report as required by §191.17.

Events that require PHMSA notification NO LATER THAN 60 Days AFTER the event:

1. A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.
2. A change in the name of the operator;
3. A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, underground natural gas storage facility, or LNG facility
4. The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to 49 CFR 49 CFR Part 192;
5. The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193; or

- | |
|---|
| 6. The acquisition or divestiture of an existing underground natural gas storage facility subject to 49 CFR part 192. |
|---|

RECORDS: The Field Office will maintain the official files on the annual pipeline report DOT **Form PHMSA F 7100.2.1**. The file will be kept for the life of the pipeline facilities.

RELATED CODE, PROCEDURES AND FORMS:

CODE REFERENCE: Title 49 CFR 191.1, 191.3, 191.7, 191.9, 191.11, 191.13 and 191.19, 191.29

California Public Utilities Commission General Order 112-F

2.2 Incidents – Reporting and Control

PURPOSE: To establish responsibilities for activities associated with certain pipeline facility incidents. These activities include, but are not limited to, incident control, repair, reporting, investigation and documentation.

See Section 2.2 of the Wild Goose Storage Emergency Response Plan for detailed guidance regarding applicable reporting requirements depending on specific circumstances.

GENERAL - D.O.T. / PHMSA Reporting:

For natural gas transmission incidents involving regulated pipelines and satisfying the Incident Criteria, each operator of a transmission, gathering pipeline, or underground natural gas storage facility must submit DOT Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5 of this part. Wild Goose Storage shall submit each report required by this procedure electronically to the Pipeline and Hazardous Materials Safety Administration at <http://portal.phmsa.dot.gov/pipeline> unless an alternative reporting method is authorized in accordance with requirements below.

If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

The **Rockpoint Gas Storage Incident Investigation Form** shall be completed and retained, to assure accurate documentation of the incident. Upon completion of the Incident Investigation form, it will be sent out to the Rockpoint 'Accident/Incident' Outlook distribution list and will be saved to the Rockpoint Intranet so that the incident is made readily available to personnel who may report or receive reports of incidents. It is recognized that only limited details will probably be available when the initial call on an incident is made, however, every effort shall be made to follow up with the incident and document all the information regarding such incident.

1. Report incidents to Federal and State safety and regulatory agencies at the earliest practicable moment following discovery, but no later than one hour after confirmed discovery. The report shall be made by telephone 800-424-8802 and shall include the following:
 1. Name(s) of operator and person(s) making report and their telephone numbers.
 2. The location of incident.
 3. The time of incident.
 4. The number of fatalities and personal injuries, if any.
 5. All other significant facts that are known by the operator that is relevant to the cause of the incident or extent of the damages.

Within 48 hours after the confirmed discovery of an incident, to the extent practicable, the Senior Compliance Manager must revise or confirm the initial telephonic notice required above with an estimate of the amount of product released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the Senior Compliance Manager must confirm the estimates that WGS gave in the initial report.

California Public Utilities Commission (CPUC) Reporting:

In the event of an incident listed in the Incident Criteria section below, the Senior Compliance Manager and/or their designate shall go to the CPUC's website, select the link to the page for reporting emergencies and follow the instructions thereon. <http://www.cpuc.ca.gov/PUC/emrep/>

1. If the Company is notified of the incident during its normal working hours, the report should be made as soon as practicable but no longer than 2 hours after the Company is aware of the incident and its personnel are on the scene.
2. If the Company is notified of the incident outside of its normal working hours, the report should be made as soon as practicable but no longer than 4 hours after the Company is aware of the incident and its personnel are on the scene.
3. All reports required by this section shall be followed by the end of the next working day by an email or telefacsimile (fax) of the standard reporting form, **"Report of Gas Leak or Interruption," CPUC File No. 420.**
4. The Company shall submit to the CPUC on DOT Form PHMSA_F7100.1 <http://ops.dot.gov/library/forms/forms.htm#7100.1> for distribution systems and on DOT Form PHMSA F7100.2 <http://ops.dot.gov/library/forms/forms.htm#7100.2> for transmission and gathering systems a report describing any incident that requires notice as described in the Incident Criteria below.
5. Together with the form required above, the Company shall furnish a letter of explanation giving a more detailed account of the incident unless such letter is deemed not necessary by the CPUC staff. The Company may confirm the necessity of a letter of explanation while making the telephonic report. If, subsequent to the initial report or letter, the Company discovers significant additional information related to the incident, the Company shall furnish a supplemental report to the CPUC as soon as practicable, with a clear reference by date and subject to the original report. These letters, forms, and reports shall be held confidential under the provisions of Paragraph 2, Exclusions, of General Order 66-C and Public Utilities Code Section 315.
6. The Company of a distribution system serving less than 100,000 customers need not submit the DOT forms required by paragraph (1) above; however, the Company must submit the letter of explanation required by (2) above, subsequent to any telephonic report to the CPUC, unless such letter is deemed unnecessary by the CPUC staff.

Quarterly Summary Reports.

Information regarding Quarterly Summary Reports can be found in Section 2.1 Pipeline Reports.

INCIDENT CRITERIA

Incidents, which meet criteria listed below, shall be reported and controlled under this procedure.

An event that involves release of flammable, toxic or corrosive gas from a pipeline facility and resulting in:

1. A death or personal injury requiring in-patient hospitalization of an employee or member of the public.
2. Estimated damages of \$149,700 (effective July 1, 2025, and is updated annually) or more, including loss to the operator and others or both, but excluding the cost of gas lost. The website link for the most current definition of an incident is <http://www.phmsa.dot.gov/incident-reporting>. Estimated damages include repair cost, cost of temporary measures, and damage to property. If in doubt, report the incident to the Operations Manager.
3. The occurrence of a ruptured pipeline or component, which allows a gas release requiring the isolation and blowdown of the facility other than planned repair and maintenance.
4. Any incident in which a regulatory agency inquiry may result due to such things as media coverage, proximity to major metropolitan areas, evacuation of buildings, traffic diversion or loss of service to a community.
5. Incidents which have either attracted public attention or have been given significant news media coverage, that are suspected to involve natural gas, which occur in the vicinity of the Company's facilities; regardless of whether or not the Company's facilities are involved (**CPUC Requirement**).
6. Any incident, which is significant in the judgment of the Superintendent, U.S. Operations, Operations Manager, and Senior Compliance Manager.
7. Incidents where the failure of a pressure relieving and limiting stations, or any other unplanned event, results in pipeline system pressure exceeding its established Maximum Allowable Operating Pressure (MAOP) plus the allowable build up set forth in 49 CFR § 192.201.
8. Incidents in which an under-pressure condition, caused by the failure of any pressure controlling device, or any other unplanned event other than excavation related damage, results in any part of the gas pipeline system losing service or being shut-down.
9. **PROCEDURE:**
10. First Responder responsibilities include the following:
 1. Establish initial control of each incident.

2. Immediately after initial control is established and a preliminary assessment or conditions can be made, call the Operations Manager, if not present, and report those incidents meeting one of the above Incident Criteria.

Operations Manager Responsibilities include the following:

1. Respond to telephone reports of those incidents meeting one of the above listed Incident Criteria.
2. Communicate the situation to designated people within the **Field Office** and **Rockpoint Operation & Engineering** office.
3. Coordinate all on-site activities including such things as repair, responding to reports, preservation of the evidence and materials, internal reporting and documentation of events and actions.
4. Secure the site and maintain as undisturbed as possible. If the site cannot be left undisturbed, document the site and incident details and preserve the site details as indicated in the appropriate system specific Emergency Response Plan or in Incident Investigation Procedure.
5. The documentation and/or investigation of incidents are necessary to meet operational requirements.
6. Following the requirements of the Rockpoint Incident Investigation Guideline
7. Arrange for interviews of employees as required.
8. Arrange for the shipment of materials or evidence to specified locations.
9. Arrange for outside professional services to assist in an investigation (e.g., corrosion specialist, land surveyor, metallurgist, or welding engineer) if deemed necessary.
10. Analyze for outside data collected, operation history of facility and results of lab testing to establish cause of failure or condition and write reports as necessary.
11. Provide recommendations for changes or facility modifications as appropriate.
12. Review written recommendations for operational procedure changes prior to issuing for field use.
13. Evaluate whether incident is reportable in conjunction with legal staff, if appropriate.
14. Complete all required forms.
15. Receive request for data, information or on-site investigation and respond to those requests after collaboration with other persons (Operations, Engineering, Safety, Legal staff, etc.) as determined necessary or appropriate.
16. Provide on-site investigation of incidents meeting one of the Incident Criteria, on a case-by-case basis.
17. Submit Department of Transportation **Form PHMSA F 7100.2** (for gathering and transmission line incidents) as soon as practical but not more than thirty

(30) days after detection of a reportable incident to D.O.T. via internet reporting.

Note: All relevant cost must be included in the estimated property damage total on the initial written incident report as well as supplemental reports. This includes (but is not limited to) cost due to property damage to the Company's facilities and to property of others, commodity/product not recovered, facility repair and replacement (including fittings used during repair which became permanently attached to the system), leak locating, right-of-way clean up and environmental clean-up and damage. Facility repair, replacement or change that is not related to the incident but is done by the Company as a matter of convenience (for example, to take advantage of access to facility unearthed because of incident) should not be included.

1. Where additional related information is obtained after a report is submitted, the Operations Manager or designate shall submit a supplemental report using Form **PHMSA F-7100.2** as soon as practical, but not less than 30 days after acquiring the additional information with a clear reference by date and subject to original report.
2. For intrastate pipelines, and in states where the state is an Agent for D.O.T., a report may be submitted in duplicate to the State agency if the regulations of that agency require submission of these reports and provide for further transmittal of one copy, within ten (10) days of receipt for incident reports to the Information Resources Manager.
3. Submit copies of all incident reports (including supplemental reports) to other agencies as required and to the Field Office.

For incidents where liability is in question, the **Rockpoint Legal Counsel** will:

1. Become an advisor to the Incident Command staff.
2. Respond to the media and/or government agencies in a positive, cooperative manner.
3. Review planned responses to outside parties, such as government agencies, outside investigators, and attorneys for information.
4. Provide advice regarding press releases.
5. In general handle all aspects of media coverage.

RECORDS:

The Rockpoint Manager, HSE will maintain the official files on incidents meeting one of the incident criteria that are reported to outside agencies.

1. Copies shall be filed by the Rockpoint Manager, HSE and/or their designate for the field location files on the Rockpoint Intranet (intranet).
2. Files will be kept for the life of the pipeline.
3. The Rockpoint Legal department shall be contacted.

CODE REFERENCE: Title 49 CFR, Sections 191.1, 191.3, 191.5, 191.7, 191.15 and 191.19; 192.605(b)(4); CPUC General Order No. 112-F

Attachment #8



**Excerpt from WGS Operations and Maintenance Manual section 3.5
highlighting revisions to address abnormal operating conditions**

- Wear pads,
- Supports or sleeves on a sample basis to confirm continued protection of the pipe, especially in areas conducive to corrosion.

Such areas would typically be those where moisture is present on the pipe due to a reason other than normal precipitation. The results of inspections, geographic location, and pipe environment will be used to determine an appropriate continuing inspection level.

Corrosion, leaks, and defects may be Safety Related Conditions. Refer to Section 2.17 Safety Related Conditions Reporting procedure.

If atmospheric corrosion is found during an inspection, the operator must take corrective action as required by 49 CFR § 192.479.

Some abnormal operating conditions operating personnel may encounter in this task include but are not limited to the following:

- Disbonded coating with visible rust and pitting of the metal underneath.
- Disbonded coating with surface rust not no pitting or significant metal loss underneath.
- Coating is bonded but has small surface blemishes.
- External coating damage.
- General and/or localized corrosion.

PROCEDURE:

Responsibility/Authority:

The Operations Manager is responsible for:

- Operator Qualifications
 - Assigning only operating personnel or contractors who are qualified to perform atmospheric corrosion checks. Assigning suitably qualified and certified personnel or contractors to perform non-destructive testing techniques, when necessary.
- Program Control
 - Maintaining a continuing program of painting based upon results of the external inspection program.
 - Ensuring repairs and preventive maintenance actions necessitated by these inspections are completed prior to the next inspection.

The Superintendent, U.S. Operations is responsible for determining whether specialty inspections are necessary and the frequency of inspection. These specialty inspections may include but not be limited to those involving non-destructive techniques, electromagnetic flux leakage or ultrasonic “smart” pigs to supplement other inspection techniques.