U.S. EPA Underground Injection Control Program

Final Permit

Class V Experimental Compressed Air Energy Storage Test Injection/Withdrawal Well

Permit No. R9UIC-CA5-FY13-1

Well Name: PG&E CAES Test Injection/Withdrawal Well
King Island Gas Field, San Joaquin County
California

Issued to:

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105

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Appendices

Part I. AUTHORIZATION TO INJECT

Pursuant to the Underground Injection Control (UIC) regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (CFR), §§124, 144, 145, 146, 147, and 148,

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105

is hereby authorized, contingent upon Permit conditions, to construct and operate a Class V experimental compressed air energy storage (CAES) injection/withdrawal (I/W) test well with one injection well, known as the Pacific Gas and Electric (PG&E) CAES injection/withdrawal (I/W) Test Well. The well will be located within Section 27, Township 3 North, Range 5 East, Northwest ¼, at PG&E facilities in the King Island Gas Field, San Joaquin County, California. Exact location of the I/W Test Well will be established and approved as outlined in this permit. The project also consists of the conversion of two existing nearby wells into monitoring wells. Piacentine 1-27 is a gas supply well and Piacentine 2-27 is a core well which was drilled in March, 2013.

For the permitted I/W Test Well, EPA will issue authorization to drill and construct only after requirements of Financial Responsibility in Part II, Section G of this permit have been met, and after the requirements of Part II Sections B-D of this permit have also been met. Operation of the well will be limited to maximum volume and pressure as stated in this permit.

If authorized, the project will consist of the injection of oxygen-depleted air into the depleted natural gas reservoir in the Mokelumne River Formation (MRF) in the King Island Gas Field for the purpose of building an air bubble as part of a "Compression Test." During and after the building of the air bubble, a series of injection, shut in, and flow tests will be conducted to investigate the reservoir's performance for a CAES application. Performance of the reservoir will be monitored by measuring specific parameters and observing formation behavior in two existing nearby wells which will serve as observation wells, in addition to the I/W Test Well. The primary injection interval sequence is identified as the MRF gas reservoir sand, and is expected to consist of at least 40 feet of net sand thickness at the I/W Test Well site at depths between approximately 4,681 to 4,721 feet true vertical depth measured from the Kelly bushing on the drill rig.

All conditions set forth herein are based on Title 40 CFR §§124, 144, 145, 146, 147 and 148 of the Code of Federal Regulations, and are regulations that are in effect on the date that this permit is effective.

This permit consists of thirty-two (32) pages plus the appendices, and includes all items listed in the Table of Contents. Further, it is based upon representations made by PG&E and on other information contained in the administrative record. It is the responsibility of the Permittee to read, understand, and comply with all terms and conditions of this permit.

This permit and the authorization to construct, test, and inject are issued for a period of five (5) years unless terminated under the conditions set forth in Part III, Section B.1 of this permit.

This permit is issued and becomes effective on 8/20/14

for Jane Diamond

Jane Diamond, Director
Water Division, EPA Region IX

Part II. SPECIFIC PERMIT CONDITIONS

A. REQUIREMENTS PRIOR TO DRILLING, TESTING, CONSTRUCTING, OR OPERATING

1. Financial Assurance

   The Permittee shall supply evidence of financial assurance prior to commencing Injection Well Drilling and Construction, in accordance with Section G of this part.

2. Field Demonstration Submittal, Notification, and Reporting

   a. Prior to each demonstration required in the following sections B through D, the Permittee shall submit plans for procedures and specifications to the EPA Region 9 Ground Water Office for approval. The submittal address is provided in Section E, paragraph 5. No demonstration in these sections may proceed without prior written approval from EPA.

   b. The Permittee must notify EPA at least thirty (30) days prior to performing any required field demonstrations in order to allow EPA to arrange to witness if so elected. EPA must approve the plans/procedures for testing before field demonstration can proceed.

   c. The Permittee shall submit results of each demonstration required in this Part to EPA within thirty (30) days of completion, unless otherwise noted.

      In lieu of using EPA reporting forms in Appendix C, California Division of Oil, Gas, and Geothermal Resources (DOGGR) reporting forms (such as a Well Summary Report) are acceptable provided all information specified by this permit is included.

B. WELL CONSTRUCTION

1. Location of Injection Well

   The injection well authorized under this permit will be located in the King Island Gas Field, San Joaquin County, California. The proposed general location of the I/W Test Well is found in Appendix A. The I/W Test Well will be drilled directionally and deviated from vertical, as described in the proposed drilling program included in Appendix B.

   Two existing wells will be used to monitor the reservoir responses during injection and falloff: Piacentine 1-27 and Piacentine 2-27. The program for converting Piacentine 1-27 from a gas well to an observation well is also detailed in Attachment L of the Application. Piacentine 2-27 does not require conversion for its intended purpose as an observation well during the compression testing.

a. Prior to drilling the I/W Test Well, the Permittee must submit proposed field coordinates (Section, Township, Range, with latitude/longitude) for the surface and bottom hole location of the I/W Test Well. The Permittee must also provide the distance between the test well and the two observation wells, as well as the location at the surface and at the true vertical depth of the top of the injection interval in the I/W Test Well and the observation wells.

b. After drilling is completed, the Permittee must submit final field surface and bottom hole coordinates (Section, Township, Range, with latitude/longitude) of the I/W Test Well constructed under this permit with the Final Well Construction Report required under paragraph 9(a) of this section. If final well coordinates differ from the proposed coordinates submitted under paragraph (a) above, justification and documentation of any communication with and approval by EPA shall be included. Also, the Permitte must provide the coordinates and distance between the I/W Test well and two observation wells at the true vertical depth of the top of the injection interval in the I/W Test Well and observation wells.

In addition, the Permittee shall submit final directional survey data and reports upon completion of the drilling operation.

2. Logging and Testing during Drilling and Construction

Logs and other tests conducted during drilling and construction shall include, at a minimum, deviation checks, directional surveys, casing logs, and injection formation tests as outlined in 40 CFR §146.12(d). Open-hole logs shall be conducted over the entire open-hole sequence below the conductor casing. The Permittee shall conduct formation evaluation wireline logging and testing operations and shall provide and use those results to estimate and report values for hydrocarbon saturation, porosity, permeability, lithology, formation water resistivity, and total dissolved solids (TDS) concentrations for both the injection and confining zones identified within the permitted geological sequence, and for selected intervals for identification of any Underground Sources of Drinking Water (USDWs) above the injection zone. A step-rate test shall be performed for evaluation of the formation fracture gradient of the proposed injection zone in accordance with Section 3.b below.

The suite of logs run from the bottom of the conductor casing (60 feet) to the bottom of the surface casing interval (600 feet) will include the dual induction log, formation compensated density log, compensated neutron log, spontaneous potential, micro-resistivity tool, gamma ray and caliper (DIL, FDC, CNL, SP, MRT, GR and CAL). The suite of logs run from the bottom of the surface casing interval (600 feet) to the full depth of the boring will include these logs, and also the sonic log, repeat formation tester (pressures only) and sidewall cores (SL, RFT, and SWC).

The Permittee must also run the Repeat Formation Tester (RFT) tool or equivalent to evaluate fluid pressures in the targeted injection zone and at selected depths above the injection zone.

In addition, the Permittee must collect sidewall core samples in the injection zone and confining zone immediately above the injection zone and provide timely copies of the sample analyses reports to EPA no later than thirty (30) days after the completion of the well (Refer to paragraph 9(a) of this section, for the required report submittal date).

After each casing is set and cementing is completed, a cement bond evaluation must be conducted over the course of the entire cased hole sequence (See Section D.2.a.iv of this part). This cement bond log evaluation shall enable the analysis of bond between cement and casing, as well as between cement and formation, and shall allow detection and assessment of any micro-annulus between the casing and cement as well as any cement channeling in the borehole annulus.

Refer to Appendix H for details on logging and testing requirements during drilling and construction operations.

3. Injection Formation Testing

Injection formation information as described in 40 CFR §146.12 (e), shall be determined through well logs, sidewall core samples, and tests and shall include porosity, permeability, static formation pressure, and effective thickness of the injection zone. Reservoir compressibility (typically coefficient "c") must also be computed. A summary of results shall be submitted to EPA with the Final Construction Report required in paragraph 9(a) of this section and updated periodically with subsequent analyses. In addition, a preliminary submittal of the static formation pressure and logging data should be provided to EPA as it is collected.

a. Ground Water Testing

During construction of the well, information relating to ground water at the site shall be obtained and submitted to EPA. This information shall include direct TDS analysis of target injection formation water to demonstrate either the presence or absence of any USDWs, (as defined in 40 CFR §§144.3 and 146.3) and the characteristics of the formation.

The Permittee shall provide well logs and representative water sample analyses from the targeted injection zone using method(s) approved by

EPA as evidence. Formation water samples from the injection zone will be collected (swabbed or other approved method) from the injection well upon its completion. Field measurements of pH, electrical conductance, and temperature will be carried out to confirm that representative MRF reservoir water is being collected. Subsequent laboratory analysis of the samples will include at least Trace Metals, Alkalinity, Conductivity, Hardness, pH, TDS, Specific Gravity (see II.E.1.a), and Oil and Grease (per 40 CFR §136.3, Table IB).

b. Step-Rate Test (SRT)

i. A SRT will be conducted in an open borehole, drilled ten (10) feet below the 9-5/8 inch casing shoe into the MRF injection zone, prior to final completion and before injection is authorized, to establish the maximum injection pressure in accordance with section D, paragraph 3 of this part. Refer to Society of Petroleum Engineering (SPE) paper #16798 for test design and analysis guidance. Detailed plans for conducting the SRT must be submitted to EPA for review, possible editing, and approval. Once approved, the Permittee may schedule the SRT, providing EPA at least thirty (30) days notice before the SRT is conducted. If available, an EPA representative will be present to monitor and evaluate the SRT.

ii. Injection as proposed in an approved SRT procedure will be temporarily authorized while the SRT is completed.

iii. Prior to testing, shut in the well long enough so that the bottom-hole pressure approximates static formation pressure, and record.

iv. Measure pressures with a down-hole pressure bomb and synchronize the data with any available data from a surface pressure recorder. Data sampling rate must allow for observation and analysis of the pressure transient behavior during each rate step as well as during the final pressure falloff period which is discussed in item vii below.

v. Use equal-length time step intervals throughout the test; these should be technically justified and should be sufficiently long to overcome well bore storage and to achieve radial flow. Use thirty (30) minute or longer time intervals unless EPA approves shorter intervals.

vi. Record at least three (3) time steps (data points on pressure vs. flow plot) before and after reaching the anticipated fracture pressure in order to obtain at least six (6) valid data points and the targeted fracture pressure. Larger rate increments may be used later in the test, but justification for this request must be approved. The data should be plotted and monitored as the test proceeds to conclusion. Refer to Appendix F - EPA Step Rate Test Policy.

vii. At the end of the test, shut down pumps and record the instantaneous shut in pressure and observe the pressure falloff for a sufficient time period to observe and later analyze the radial flow portion of the injection zone during the SRT. The length of time for pressure falloff observation must be determined and discussed in the Permittee's submission plans in advance of conducting the SRT.

viii. The Permittee shall report the results to EPA within thirty (30) days of conducting the SRT. Results shall include analyses of the pressures versus rate and the transmissivity and storativity for the stepped rates throughout the SRT by analyzing the pressure transient data.

c. Fall Off Pressure Test (FOT)

To determine and to monitor formation characteristics, an initial FOT shall be run at the end of the SRT after a radial flow regime has been established at an injection rate which is representative of the expected fluid contribution to the well at a water injection rate which is equivalent or representative of to the proposed air injection rate during the CAES test. The FOT will be conducted in accordance with EPA guidance found in Appendix E. The Permittee shall use the test results to recalculate the Zone of Endangering Influence (ZEI, as defined in 40 CFR §146.6) and to evaluate whether any corrective action will be required (refer to Section C of this part); a summary of the recalculation shall be included with the FOT report. Detailed plans for conducting the FOT must be submitted to EPA for review and approval. Once approved, the Permittee may schedule the FOT, providing EPA at least thirty (30) days advance notice before the test is conducted. EPA will be notified again ten (10) days prior to the test to confirm the schedule for the FOT. The final FOT report shall be submitted to EPA within thirty (30) days of test completion. Refer to Appendix H for details on injection formation testing requirements.

i. Thereafter, fall-off testing shall be repeated as part of the bubble-building, equilibration, and injection/withdrawal phases of the injection testing program, as described in Appendix H of this permit. The results of the tests shall be submitted no later than thirty (30) days after the test is performed.

ii. The latest static reservoir pressure and its cumulative behavior over time on a graphic plot of the injection zone shall be determined and reported with the FOT reports listed above.

d. Particulate filters may be used upstream of the injection well, at the discretion of the Permittee, to prevent formation plugging or damage from particulate matter. The Permittee shall include any filter specifications in the Final Construction Report required in paragraph 9(a) of this section, including proposed particle size removal with any associated justification for the selected size. For any particulate filters used, follow appropriate waste analysis and disposal practices, and provide documentation of such.

4. Drilling, Work-over, and Plugging Procedures

Drilling, work-over, and plugging procedures must comply with the DOGGR "Onshore Well Regulations" of the California Code of Regulations, found in Title 14, Natural Resources, Division 2, Department of Conservation, Chapter 4, Article 3, Section 1722-1723. Drilling procedures shall also include the following:

a. Details for staging long-string cementing or justification for cementing without staging.

b. Records of daily Drilling Reports (electronic and hard copies).

c. Blowout Preventer (BOP) System testing on recorder charts including complete explanatory notes during the test(s).

d. Casing and other tubular and accessory measurement tallies.

e. Details and justification for any open hole gravel packing.

f. Directional drilling records and reports.

Procedures provided on reporting forms such as DOGGR's Well Summary Report are acceptable provided all required information as specified above is included.

5. Casing and Completion Specifications

Notwithstanding any other provisions of this permit, the Permittee shall case and cement the injection well to prevent the movement of fluids into or between USDWs. Cement evaluation analyses shall be performed as described in Section D paragraph 2.a.iv of this part. Casing shall be maintained until the test well is plugged and abandoned. The proposed well construction procedures and schematics are presented in Appendix B.

EPA may require minor alterations to the construction requirements based upon information obtained during well drilling and related operations, for example, if the proposed casing setting depths will not completely cover the base of the USDWs and the confining formation located immediately above the injection zone.

Final casing setting depths will be determined by the field conditions, well logs, formation fluid samples and other input from the drilling operation and initial testing data. EPA approval will be obtained for any revisions prior to installation, and these will be documented in the Final Well Construction Report (See paragraph 9(a) below).

6. Injection Interval

Injection shall be permitted for the MRF reservoir sand at depths estimated from about 4,730 to 4,772 feet measured depth and 4,681 to 4,721 feet true vertical depth measured from the Kelly bushing on the drill rig.

Minor alteration of the depth of the injection zone interval and the casing setting depth are expected to be realized upon drilling. These alterations and other rework operations that may occur later in the course of well operation are considered minor for this permit and must be reported (refer to EPA Form 7520-12 listed in Appendix C).

7. Confining Layer

The overlying confining layers at the PG&E well site are the 35 to 110-foot thick Capay Shale immediately above the proposed injection target interval, and shale layers in the upper section of the Meganos Channel Fill formation that truncates the MRF reservoir sand unit at the periphery of the reservoir.

Field information on the Capay Shale Formation confining layer, including its geophysical characteristics, thickness, and local structure will be obtained and updated during drilling of the injection well and shall be included in the Final Well Construction Report required in paragraph 9(a) of this section.

8. Monitoring Devices

The Permittee shall install and maintain in good operating condition:

a. A gas sampling port in the injection/withdrawal pipe manifold near the wellhead for the purpose of obtaining representative samples of injection and flowing gases to verify the accuracy of the hydrocarbon and oxygen meters.

b. Devices to continuously measure and record injection pressure, annulus pressure, flow rate, and injection volumes, subject to the following:

   i. Pressure gauges shall be of a design to provide:

      1) A full pressure range of at least fifty (50) percent greater than the anticipated operating pressure.

      2) A calibrated and certified deviation accuracy of five (5) percent or less throughout the operating pressure range.

   ii. Flow meters shall measure cumulative volumes and be calibrated and certified for a deviation accuracy of five (5) percent or less throughout the range of injection rates allowed by the permit.

c. Two hydrocarbon sensors shall be installed in series as close to the I/W Test Well wellhead as practicable. The sensors will operate on two different technologies (infrared [IR] detector and flame ionization detector [FID]) to provide robust detection capability for varying conditions. The sensors will be hard wired to the central data acquisition and control module.

d. A flame sensor shall also be installed as part of the I/W Well manifold monitoring package and will be hard wired to the central data acquisition and control system. If the flame sensor is activated, an alarm will sound and the master automated valve will immediately close to shut in the well and cease the injection and flow process.

e. Redundant oxygen sensors shall be installed on the I/W pipeline between the nitrogen generator and the wellhead to continuously monitor the oxygen content of the injected gas. The sensors will be hard wired to the central data acquisition and control module.

f. The I/W Test Well shall be fitted with downhole and wellhead pressure-temperature (PT) sensors that will be hard wired to the central data acquisition and control module. The control logic for the wellhead pressure sensor will include an alarm and interlock that closes the automated control valve and prevents wellhead injection pressure from exceeding the maximum allowable injection pressure.

g. The Piacentine 1-27 Well shall be fitted with a wellhead PT sensor, and data will be transmitted to the central data acquisition and control module wirelessly.

h. The I/W Test Well and Piacentine 1-27 Well shall be fitted with annular PT sensors. The I/W Test Well sensors will be hard wired to central data acquisition and control module, and the Piacentine 1-27 well sensors shall transmit data wirelessly.

i. The central data acquisition and control system shall be provided with an uninterruptable power supply so that critical data acquisition for system operation and compliance can continue in the event of a power failure or outage, and acquired data will not be lost.

9. Final Well Construction Report and Completion of Construction Notice.

a. The Permittee must submit a final well construction report including logging, coring, and other results, with a schematic diagram and detailed description of construction, including driller's log, materials used (i.e., tubing tally, and particulate filters, if any, and cement (and other) volumes, to EPA within sixty (60) days after completion of the I/W Test Well. The completion report must also include the details for the two observation wells.

b. The Permittee must also submit a notice of completion of construction to EPA (Form 7520-9 listed in Appendix C). Injection operations may not commence until all well and formation testing is complete, necessary reports are submitted, and EPA has inspected or otherwise reviewed and approved the construction and other details for the injection and observation wells, and notified the Permittee that it is in compliance with the conditions of the permit.

10. Proposed Changes and Workovers

a. The Permittee shall give advance notice to EPA, as soon as possible, of any planned physical alterations or additions to the permitted injection well and/or observation wells. Any changes in well construction require prior approval by EPA and may require a permit modification under the requirements of 40 CFR §§144.39 and 144.41.

b. In addition, the Permittee shall provide all records of well workovers, logging, or other subsequent test data, including required mechanical integrity testing, to EPA within thirty (30) days of completion of the activity.

c. Appendix C contains a list of the appropriate reporting forms.

d. Demonstration of mechanical integrity shall be performed within thirty (30) days of completion of workovers or alterations and prior to resuming injection activities, in accordance with Section D paragraphs 1.a and 2 of this part.

C. CORRECTIVE ACTION

Corrective action will not be required in the existing wells located within the Area of Review (AOR, defined in 40 CFR §146.6), subject to a review of geophysical logs, sidewall cores, reservoir pressure, FOT data and model results obtained before injection commences. If the AOR is enlarged as a result of the updated model results, additional wells located within the expanded AOR may require corrective action before injection is authorized in the I/W Test Well.

1. Initial Zone of Endangering Influence (ZEI) re-evaluation with Field Data

   Data resulting from testing performed under Section B paragraphs 2 and 3, and Section C, in this part, will be used by the Permittee to confirm or modify assumptions used to calculate the original ZEI (see Section II.B.3.c). If new field data results in a ZEI larger than the AOR, and there are wells within the expanded area that penetrate the proposed zones of injection, a corrective action plan shall be proposed to EPA for approval and implemented as described in paragraph 3 of this section.

2. Interim ZEI Review

   The Permittee shall review the ZEI calculation based on any new data obtained from the FOT and static reservoir pressure tests required in Section B, paragraph 3(c) of this part. A copy of the modified ZEI calculations, along with all associated assumptions or justifications, shall be provided to EPA within thirty (30) days of completing the FOT.

3. Implementation of Corrective Actions

   a. If any additional wells requiring corrective action are found within the modified ZEI, a list of these wells along with their locations and construction data shall be provided to EPA within thirty (30) days of their identification.

   b. The Permittee shall submit a plan to re-enter, plug, and abandon the wells listed in paragraph a above in a way that prevents the migration of fluids into a USDW.

   c. The Permittee may not commence corrective action activities without prior written approval from EPA.

D. WELL OPERATION

Planned test well operations and the formation testing program are described in detail in the Operations and Testing Plans included in Appendix H. Well operations and testing shall conform to the Operations and Testing Plan, and the following conditions:

1. Demonstrations Required Prior to Injection

Injection operations may not commence until construction is complete and the Permittee has complied with the following paragraphs, a and b:

a. Mechanical Integrity

The Permittee shall demonstrate that the I/W Test Well and observation well Piacentine 1-27 maintain mechanical integrity consistent with 40 CFR §146.8 and with paragraph 2 of this section. The Permittee shall demonstrate that there are not significant leaks in the casing and tubing and that there is not significant fluid movement into or between USDWs through the casing wellbore annulus or vertical channels adjacent to the injection wellbore of each well. The Permittee may not commence initial injection into the test well nor recommence injection after a workover which has compromised well integrity in either well until it has received written notice from EPA that such a demonstration is satisfactory.

The observation well Piacentine 2-27 is fully cased and cemented but is not perforated. Although a pressure test of the casing is not required for mechanical integrity demonstration, temperature logging may be required to assess possible fluid movement in the cemented annulus during the CAES test and in the post-test monitoring period if reservoir pressure remains above normal hydrostatic pressure.

b. Injectate Hazardous Waste

Hazardous waste as defined in 40 CFR §261 may not be injected at any time into the well.

2. Mechanical Integrity

a. Mechanical Integrity Tests (MITs)

Mechanical integrity testing shall conform to the following requirements throughout the life of the I/W Test Well and prior to control of the Piacentine 1-27 observation well being returned to the current owner, if applicable.

i. Casing/tubing annular pressure (internal MIT)

A demonstration of the absence of significant leaks in the casing, tubing and/or liner shall be made by performing a pressure test on the annular space between the tubing and long string casing. This test shall be for a minimum of thirty (30) minutes at a pressure equal to or greater than the maximum allowable injection pressure. A well passes the MIT if there is less than a five (5) percent change in pressure over the thirty (30) minute period. A pressure differential of at least three hundred and fifty (350) pounds per square inch (psi) between the tubing and annular pressures shall be maintained throughout the MIT.

ii. Continuous pressure monitoring

The tubing/casing annulus pressure and tubing pressure shall be monitored and recorded continuously by a digital instrument with a resolution of one tenth (0.1) psi. The average, maximum, and minimum monthly results shall be included in the next report to EPA per Section E paragraph 5.b of this part unless more detailed records are requested by EPA.

iii. Injection profile survey and Temperature Logs (external MIT)

A demonstration that the injectate is confined to the proper zone shall be conducted in the I/W Test Well and presented by the Permittee and subsequently approved by EPA. This demonstration shall consist of a thermal decay log and a spinner log (as specified in Appendix D) or other diagnostic tool or procedure as approved by EPA. A temperature log may be required to assess external mechanical integrity and fluid movement into or between USDWs in both the observation wells during the CAES test, or during the post-test monitoring period, if reservoir pressures exceed normal hydrostatic pressure. Detailed plans for conducting the external MIT must be submitted to EPA for review and approval. Once approved, the Permittee may schedule the external MIT, providing EPA at least thirty (30) days notice before the external MIT is conducted. The demonstration shall be scheduled to occur approximately ninety (90) days after commencement of injection.

iv. Cement Evaluation Analysis

After installing and cementing casing, conducting a cement squeeze job, or any well cement repair, for the I/W Test Well or the observation wells under this permit, the Permittee shall submit cementing records and cement evaluation logs that demonstrate isolation of the injection interval and other formations from underground sources of drinking water. Surface casing and long string casing well bore annuli in the I/W Test Well shall be cemented to surface. Analysis shall include cement evaluation performed after each casing is set and cemented. Cement evaluation must assess the following four objectives:

1) Bond between casing and cement.
2) Bond between cement and formation.
3) Detection and assessment of any micro-annulus (small gaps between casing and cement).
4) Identification of any cement channeling in the borehole annulus.

The Permittee may not commence or recommence injection until it has received written notice from EPA that the cement evaluation/demonstration is satisfactory.

b. Schedule for MITs

EPA may require that an MIT be conducted at any time during the permitted life of any well authorized by this permit. The Permittee shall also arrange and conduct MITs according to the following requirements:

i. Within thirty (30) days from completion of any work-over where well integrity is compromised, or within thirty (30) days when any loss of mechanical integrity becomes evident during operation. An internal pressure MIT shall be conducted on the well which lost mechanical integrity.

ii. An injection profile survey external MIT shall be conducted on the permitted I/W Test Well in accordance with 40 CFR §146.8 and paragraph a.iii above.

iii. An internal pressure MIT shall be conducted on the permitted injection well in accordance with 40 CFR §146.8 and paragraph a.i above at the conclusion of the CAES post-test monitoring period and every two (2) years thereafter while in inactive status. An internal pressure MIT shall be conducted on the Piacentine 1-27 observation well in accordance with 40 CFR §146.8 and paragraph a.i above prior to conversion to production service.

c. Loss of Mechanical Integrity

The Permittee shall notify EPA, in accordance with Part III, Section E paragraph 10 of this permit, under any of the following circumstances:

i. The well fails to demonstrate mechanical integrity during a test, or

ii. A loss of mechanical integrity becomes evident during operation, or

iii. A significant change in the annulus or injection pressure occurs during normal operating conditions. See Section D.6.b of this part below.

Furthermore, in the event of i, ii, or iii, injection activities shall be suspended immediately and operation shall not be resumed until the Permittee has taken necessary actions to restore and confirm mechanical integrity of the well and EPA gives approval to recommence injection.

d. Prohibition without Demonstration

After the permit effective date, injection into the well may continue only if:

i. The well has passed an internal pressure MIT in accordance with paragraph 2.a.i of this section; and

ii. The Permittee has received written notice from EPA that the internal pressure MIT demonstration is satisfactory.

3. Injection Pressure Limitation

a. Maximum allowable injection pressure measured at the wellhead, to be applied to the permitted injection well, shall be based on results of the SRT conducted under Section B, paragraph 3(b) of this part. EPA will provide the Permittee written notification of the maximum allowable injection pressure for the injection well constructed and operated under this permit, and the established limits will be incorporated into the permit using minor modification procedures (see 40 CFR §144.41).

b. The Permittee may request an increase in the maximum injection pressure allowed under the provisions of paragraph 3(a) above. Any such request shall be made in writing and justified to EPA with the results of a SRT conducted as described in Section B, paragraph 3(b) of this part.

c. Any approval granted by the Director for increased injection pressure as stated in paragraph 3(b), above, shall be made part of this permit by minor modification procedures (see 40 CFR §144.41).

d. In no case shall pressure in the injection zone during injection initiate new fractures or propagate existing fractures in the injection zone or the confining zone. In no case shall injection pressure cause the movement of injection or formation fluids into or between underground sources of drinking water.

4. Injection Volume (Rate) Limitation

a. The injection rate shall not exceed 14 million standard cubic feet per day (MMscfd) at any time and the actual injection volume shall not exceed 560 MMscf cumulatively. The rate and cumulative injection volumes will be subject to a review of the initial and interim ZEI determinations performed as described in Section C.1 and 2.

b. The Permittee may request an increase in the maximum injection rate or volume allowed in paragraph a above. Any such request shall be made in writing and justified to EPA.

c. Should any increase in injection rate or volume be requested, the Permittee shall demonstrate to the satisfaction of EPA that the proposed increase will not interfere with the operation of the facility, its ability to meet conditions described in this permit, change its well classification, or cause migration of injectate or pressure buildup to occur beyond the AOR.

d. Any approval granted by the Director for increased injection volume as stated in paragraph 4(b), above, shall be made part of this permit by minor modification procedures (see 40 CFR §144.41) if the demonstration required in paragraph 4(c) is satisfactory.

e. The injection rate shall not cause an exceedance of the injection pressure limitation established under item 3(a) of this section.

5. Injection and Withdrawal Fluid Limitations

Injection fluids will consist initially of oxygen-depleted air (less than five (5) percent oxygen, consisting mostly of nitrogen) generated from a membrane separation system to remove oxygen from the injection stream. Based on the results of testing with oxygen-depleted air for approximately sixty five (65) days, a short test (approximately eleven (11) days) involving injection of ambient air may be conducted if certain decision criteria are met, including stringent safety criteria. The combustible gas content of the withdrawn air stream shall be monitored continuously during I/W testing, and a safety shut down interlock will be triggered to stop withdrawal if the combustible gas concentration reaches five (5) percent when injecting oxygen-depleted air. If testing is conducted with ambient air, the combustible gas concentration limit shall be two (2) percent.

a. The Permittee shall not inject any hazardous waste, as defined by 40 CFR §261, at any time. See also paragraph 1.b of this section.

b. Injection fluids shall be limited to only fluids authorized by this permit and generated by PG&E at the King Island CAES Test Facility. No fluids shall be accepted from other sources for injection into the permitted well.

The Permittee is required to notify EPA in writing at least forty-five (45) days prior to its planned injection of oxygen-depleted air into the I/W Test Well. At least five (5) days notice shall be provided to EPA if a decision is made to inject ambient air following evaluation of the oxygen-depleted air injection/withdrawal test. In addition, the Permittee must submit to EPA, prior to initial injection of oxygen-depleted air into the I/W Test Well, analytical results of this fluid in accordance with the requirements in permit condition Section E, paragraph 1. Once injection of the oxygen-depleted air, and if injection of ambient air is proposed, and approved, analytical results shall be reported to EPA within thirty (30) days of testing, and shall be included in the next report in accordance with reporting requirements under Section E, paragraph 5.c below.

c. Any well stimulation or treatment procedure performed at the discretion of the Permittee shall be proposed and submitted to EPA for approval prior to implementation.

6. Tubing/Casing Annulus Requirements

a. Corrosion-inhibiting annular fluid shall be used and maintained during well operation. A complete description and characterization shall be submitted to EPA for approval before use.

b. An approximate pressure of one hundred (100) psi at shut-in conditions shall be maintained on the tubing/casing annulus by injecting a nitrogen blanket in the uppermost portion of the annulus. Within the first month of normal injection operations, the Permittee shall monitor and determine the cyclic range of annular pressure fluctuation for the well. This pressure range shall be submitted within thirty (30) days of completing the analysis. Any annular pressure measured outside of this established normal pressure range shall be reported orally within twenty-four (24) hours, followed by a written submission within five (5) days, as a potential loss of mechanical integrity and per Paragraph 2.c of this section and Part III. E. 10. Event details, including associated injection pressures and temperatures shall be submitted to EPA for review and consultation as to whether a loss of mechanical integrity occurred.

c. Annular pressure-temperature changes shall be evaluated to verify whether they are due to thermal effects or represent well integrity failures. The expected magnitude of potential pressure changes due to thermal effects shall be calculated prior to the beginning of injection operations and further evaluated early during the injection process. The results of that evaluation shall be submitted to EPA within thirty (30) days of completing that analysis.

E. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Fluid Monitoring Program

Injection fluids (gas samples) will be analyzed to yield representative data on their oxygen content. As shown in Appendix H, the Permittee shall take samples at or before the wellhead for analysis of oxygen and other fixed gas content at startup and end of the initial oxygen-depleted air injection, and at startup and end of ambient air injection, if conducted, for analysis as shown in Appendix H. In addition, the Permittee shall continuously monitor the oxygen content described in Appendix H. All test results shall be submitted to EPA based on the schedule provided in paragraph 5 below.

Samples and measurements shall be representative of the monitored activity. The Permittee shall utilize analytical methods approved by EPA.

a. Analysis of injection fluids.

Within five (5) days after the start of injection, or whenever there is a change in injection fluids, injectate sampling and analyses shall be performed as outlined above.

2. Monitoring Information

Records of monitoring activity required under this permit shall include:

a. Date, exact location, and time of sampling or field measurements.

b. Name(s) of individual(s) who performed sampling or measuring.

c. Exact sampling method(s) used.

d. Date(s) laboratory analyses were performed.

e. Name(s) of individual(s) who performed laboratory analyses.

f. Types of analyses.

g. Results of analyses.

3. Monitoring Devices

a. Continuous monitoring devices

Injectate rate/volume, injectate temperature, annular pressure, and injection pressure shall be measured at the wellhead using equipment of sufficient precision and accuracy. All measurements must be recorded at minimum to a resolution of one tenth of the unit of measure (e.g. injection rate and volume must be recorded to a resolution of a tenth of a MMscf; pressure must be recorded to a resolution of a tenth of a psig; injection fluid temperature must be recorded to a resolution of a tenth of a degree Fahrenheit). Exact dates and times of measurements, when taken, must be recorded and submitted. The I/W Test Well shall have a dedicated flow meter, installed so as to record all injection flow. The Permittee shall monitor the following parameters, at the prescribed frequency, and record the measurements at this required frequency, using the prescribed instruments. For this permit, continuous monitoring requires a minimum frequency of at least one data point every thirty (30) seconds:

Monitoring Parameter	**Frequency**	**Instrument**
Injection rate (MMscfd)	Continuous	digital recorder
Daily Injection Volume (MMscf)	Daily	digital totalizer
Total Cumulative Volume (MMscf)	Continuous	digital totalizer
Well head injection pressure (psig)	Continuous	digital recorder
Annular pressure (psig)	Continuous	digital recorder
Injection fluid temperature (degrees Fahrenheit)	Continuous	digital recorder

The Permittee must adhere to the required format below for reporting injection rate and well head injection pressure. An example of the required electronic data format:

DATE	TIME	INJ. PRESS (psig)	INJ. RATE (MMscfd)
06/27/10	16:33:16	1025.6	5.8
06/27/10	17:33:16	2075.4	10.3

Each data line shall include four (4) values separated by a consistent combination of spaces or tabs. The first value contains the date measurement in the format of mm/dd/yy or mm/dd/yyyy, where mm the number of the month, dd is the number of the day and yy or yyyy is the number of the year. The second value is the time measurement, in the format of hh:mm:ss, where hh is the hour, mm are the minutes and ss are the seconds. Hours should be calculated on a twenty-four (24)-hour basis, i.e. 6 PM is entered as 18:00:00. Seconds are optional. The third value is the well head injection pressure in psig. The fourth column is injection rate in MMscfd.

b. Calibration and Maintenance of Equipment

All monitoring and recording equipment shall be calibrated and maintained on a regular basis to ensure proper working order of all equipment.

c. Observation Well Monitoring

Pressures and temperatures will be monitored continuously at the wellhead of the Piacentine 1-27 observation well with PT sensors installed on the tubing and tubing/casing annulus.

Static bottomhole and wellhead pressures shall be measured in the Citizen Green 1 Well prior to commencement of compression testing and wellhead pressures shall be monitored daily during the compression test. Bottomhole pressures shall be calculated from wellhead pressures during the compression test.

4. Recordkeeping

The Permittee shall retain the following records and shall have them available at all times for examination by EPA personnel, in accordance with the following:

a. All monitoring information, including required observations, calibration and maintenance records, recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the permit application.

b. Information on the physical nature and chemical composition of all injected fluids.

c. Records and results of MITs, any other tests required by EPA, and any well workovers completed.

d. The Permittee shall maintain copies (or originals) of all records described in paragraphs a through c above during the operating life of the well and shall make such records available at all times for inspection at the facility.

e. The Permittee shall only discard the records described in paragraphs a through d if:

i. The records are delivered to the EPA Region 9 Ground Water Office, or

ii. Written approval from the Regional Administrator to discard the records is obtained.

5. Reporting

The Permittee shall submit, in accordance with the required schedule, accurate reports to EPA containing, at minimum, the following information:

a. Quarterly, hourly and daily values, submitted in electronic format, for the continuously monitored parameters specified for the injection well in paragraph 3.a of this section.

b. Quarterly, monthly cumulative total volumes, as well as monthly average, minimum, and maximum values for the continuously monitored rate, pressure, and temperature parameters specified for the injection well in paragraph 3.a of this section, unless more detailed records are requested by EPA.

c. Periodic analyses, to be included in the next monthly report, for injection fluid characteristics for parameters specified in paragraph 1 of this section and described in Appendix H.

d. To be included with the next report immediately following the test, but no later than thirty (30) days after completion of the test/workover, the results of any additional MITs or other tests required by EPA, and any well workovers completed.

i. FOT results as required in Section B, paragraph 3.c.ii of this part.

ii. Shut-in static reservoir pressure cumulative behavior plot of the injection zone, as required in Section B, paragraph 3.c.iii of this part.

e. Static bottomhole and wellhead pressures measured in the Citizen Green 1 Well prior to commencement of injection shall be reported in the first monthly report. These wellhead pressures must be monitored daily and reported monthly during the compression test, and quarterly in the post-test period.

f. A narrative description of all non-compliance that occurred during the reporting period.

g. Progress is expected throughout this test regarding theoretical predictive analysis and application techniques as new data are acquired and various reservoir and geological characteristics and properties are obtained and confirmed. Include in the quarterly report updates comparing test results to the predictive models.

Monthly reports, with the applicable Appendix C forms, shall be submitted for the operating periods during the test. After test completion, reporting will be required on a quarterly basis and the reports must be submitted on the following schedule:

Reporting Period	Report Due
Jan, Feb, Mar	Apr 28
Apr, May, June	July 28
July, Aug, Sept,	Oct 28
Oct, Nov, Dec	Jan 28

Monitoring results and all other reports required by this permit shall be submitted to the following address:

U.S. Environmental Protection Agency, Region 9
Water Division
Ground Water Office (Mail Code WTR-9)
75 Hawthorne St.
San Francisco, CA 94105-3901

Copies of all reports shall also be provided to the following:

California Division of Oil, Gas, and Geothermal Resources, District 6
801 K Street
Sacramento, CA 95814

California Regional Water Quality Control Board, Central Valley Region
11020 Sun Center Drive, Suite 200
Rancho Cordova, CA 95670

F. PLUGGING AND ABANDONMENT

1. Notice of Plugging and Abandonment

The Permittee shall notify EPA no less than sixty (60) days before abandonment of any well authorized by this permit. EPA may require that plugging and abandonment activities be witnessed by an EPA representative.

2. Plugging and Abandonment Plans

The Permittee shall plug and abandon the well(s) as provided in Appendix G (Permit Application Attachment Q), consistent with State of California requirements and 40 CFR §146.10. EPA reserves the right to change the manner in which a well will be plugged if the well is modified during its permitted life, if the well is not consistent with EPA requirements for construction or mechanical integrity, or otherwise at EPA's discretion.

3. Cessation of Injection Activities

After a cessation of injection operations for two (2) years, a well is considered inactive. In this case, the Permittee shall plug and abandon the inactive well(s) in accordance with the Plugging and Abandonment Plans, unless it:

a. Provides notice to EPA.

b. Has demonstrated that the well(s) will be used in the future.

c. Has described actions or procedures, satisfactory to EPA, which will be taken to ensure that the well(s) will not endanger underground sources of drinking water during the period of inactivity, including biennial temperature logs to demonstrate external mechanical integrity of the well(s) if static reservoir pressure exceeds normal hydrostatic pressure.

d. Conducts an internal MIT in the I/W Test Well and Piacentine 1-27 Well every two (2) years if static reservoir pressure exceeds normal hydrostatic pressure while the well remains inactive; mechanical integrity must be restored if the well fails the MIT.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging any well, the Permittee shall submit a report on Form 7520-14, provided in Appendix C, to EPA. The report shall be certified as accurate by the person who performed the plugging operation and shall consist of either:

a. A statement that the well was plugged in accordance with the approved Plugging and Abandonment Plans, or

b. Where actual plugging differed from the Plugging and Abandonment Plans, a statement specifying and justifying the different procedures followed.

G. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility

The Permittee is required to demonstrate and maintain financial responsibility and resources sufficient to close, plug, and abandon the underground injection operation as provided in the Plugging and Abandonment Plans and consistent with 40 CFR §144.63 Subpart F, which the Director has chosen to apply.

a. The Permittee shall implement an approved financial assurance mechanism to demonstrate adequate financial responsibility in the amount of $1,269,000. Authority to inject and operate the well under the authority of this permit will be granted only after the financial assurance mechanism is in place and approved by EPA.

b. The level of financial responsibility shall be reviewed and updated periodically, upon request of EPA. The Permittee may be required to change to an alternate method of demonstrating financial responsibility. Any such change must be approved in writing by EPA prior to the change.

c. EPA may require the Permittee to estimate and to update the estimated plugging cost periodically. Such estimates shall be based upon costs that a third party would incur to plug the wells with appropriate contingencies.

2. Insolvency of Financial Institution

The Permittee must submit an alternate instrument of financial responsibility acceptable to EPA within sixty (60) days after either of the following events occurs:

a. The institution issuing the bond or other financial instrument files for bankruptcy; or

b. The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

Failure to submit an acceptable financial demonstration may result in the termination of this permit pursuant to 40 CFR §144.40(a) (1).

3. Insolvency of Owner or Operator

An owner or operator must notify EPA by certified mail of the commencement of voluntary or involuntary proceedings under U.S. Code Title 11 (Bankruptcy), naming the owner or operator as debtor, within ten (10) business days. A guarantor of a corporate guarantee must make such a notification if he/she is named as debtor, as required under the terms of the guarantee.

H. DURATION OF PERMIT

This permit and the authorization to inject are issued for a period of five (5) years unless terminated under the conditions set forth in Part III, Section B.1 of this permit.

Part III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection well construction and operation in accordance with the conditions of this permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into USDWs (both as defined in 40 CFR §§144.3 and 146.3).

Any underground injection activity not specifically authorized in this permit is prohibited. The Permittee must comply with all applicable provisions of the Safe Drinking Water Act (SDWA) and 40 CFR §§124, 144, 145, and 146. Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, 42 U.S.C. § 300(i), or any other common law, statute, or regulation other than Part C of the SDWA. Issuance of this permit does not convey property rights of any sort or any exclusive privilege, nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Nothing in this permit shall be construed to relieve the Permittee of any duties under all applicable laws or regulations.

B. PERMIT ACTIONS

1. Modification, Revocation and Reissuance, or Termination

   EPA may, for cause or upon request from the Permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR §§124.5, 144.12, 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR §144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance by the Permittee, does not stay the applicability or enforceability of any permit condition. EPA may also modify, revoke and reissue, or terminate this permit in accordance with any amendments to the SDWA if the amendments have applicability to this permit.

2. Transfers

   This permit is not transferable to any person unless notice is first provided to EPA and the Permittee complies with requirements of 40 CFR §144.38. EPA may require modification or revocation and reissuance of the permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the SDWA.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR §§2 and 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures contained in 40 CFR §2 (Public Information). Claims of confidentiality for the following information will be denied:

1. Name and address of the Permittee, or

2. Information dealing with the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply

   The Permittee shall comply with all applicable UIC Program regulations and all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with 40 CFR §144.34. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, or modification, or denial of a permit renewal application. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions

   Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may also be subject to enforcement actions pursuant to RCRA. Any person who willfully violates a permit condition may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense, for the Permittee in an enforcement action, that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

4. Duty to Mitigate

The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from noncompliance with this permit.

5. Proper Operation and Maintenance

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

6. Property Rights

This permit does not convey any property rights of any sort, or any exclusive privilege.

7. Duty to Provide Information

The Permittee shall furnish to EPA, within a time specified, any information which EPA may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to EPA, upon request, copies of records required to be kept by this permit.

8. Inspection and Entry

The Permittee shall allow EPA, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

a. Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit.

b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit.

c. Inspect and photograph at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit.

d. Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

9. Signatory Requirements

All applications, reports, or other information submitted to EPA shall be signed and certified by a responsible corporate officer or duly authorized representative according to 40 CFR §§122.22 and 144.32.

10. Additional Reporting

a. Planned Changes – The Permittee shall give notice to EPA as soon as possible of any planned physical alterations or additions to the permitted facility.

b. Anticipated Noncompliance - The Permittee shall give advance notice to EPA of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

c. Compliance Schedules - Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted to EPA no later than thirty (30) days following each schedule date.

d. Twenty-four Hour Reporting

i. The Permittee shall report to EPA any noncompliance which may endanger health or the environment. The following information shall be provided orally within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances:

1) Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water.

2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water.

ii. A written submission of all noncompliance as described in paragraph (i) shall also be provided to EPA within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

e. Other Noncompliance - At the time monitoring reports are submitted, the Permittee shall report in writing all other instances of noncompliance not otherwise reported. The Permittee shall submit the information listed in Part III, Section E.10.d of this permit.

f. Other Information - If the Permittee becomes aware that it failed to submit all relevant facts in the permit application, or submitted incorrect information in the permit application or in any report to EPA, the Permittee shall submit such facts or information within two (2) weeks of the time such facts or information becomes known.

11. Continuation of Expiring Permit

a. Duty to Reapply - If the Permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the Permittee must submit a complete application for a new permit at least one hundred and eighty (180) days before this permit expires.

b. Permit Extensions - The conditions and requirements of an expired permit continue in force and effect in accordance with 5 U.S.C. §558(c) until the effective date of a new permit, if:

i. The Permittee has submitted a timely and complete application for a new permit.

ii. EPA, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

Path. J:\GIS\WPPGE_CAES\SectionF\Others-To\05-12-2014\Figure 1 Isocore Locations.mxd

Prepared for **PACIFIC GAS AND ELECTRIC COMPANY**	PG&E	*PG&E CAES PROJECT COMPRESSION TESTING I/W WELL UIC APPLICATION*				*FIGURE 1* ***KING ISLAND RESERVOIR AND WELL LOCATIONS***
		PROJECT NO. 03.WP.004	DATE 05/12/14	DRAWN BY DPG	APPR. BY RF	

APPENDIX B – Construction Procedures and Proposed Well Schematics

ATTACHMENT L

Construction Procedures

Contents

L.1 REQUIREMENTS

Discuss the construction procedures to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the drilling, testing and coring program, and proposed annulus fluid.

L.2 APPROACH AND RATIONALE

The proposed Injection/Withdrawal Well will be installed as a deviated well from the existing well pad used for construction of the Piacentine 2-17 core well. The bottomhole location (used as the well location in this application) will be located approximately 180 feet northeast of the existing Piacentine 1-27 well in order to inject the air at a favorable location in the reservoir structure, and to facilitate use of Piacentine 1-27 and 2-27 as monitoring wells. The well will be drilled using conventional gas well drilling equipment, and will be completed in the top of the reservoir by under-reaming and installing a screen and gravel pack to promote good communication with the reservoir sands. Air will be injected and withdrawn through 5 ½-inch tubing secured in the casing with a packer system and a pressurized annulus. The well will be completed using 600 feet of 14 ¾-inch surface casing and 4,730 feet of 9 5/8-inch long string casing cemented to the surface.

The proposed surface casing (600 feet) will extend below the anticipated Base of Fresh Water as defined by the State of California rather than to the base of Underground Sources of Drinking Water (USDW) as defined by EPA. The proposed Injection/Withdrawal Well is a Class V Experimental Injection Well that will be used for a short-term air injection pilot test. This use is fundamentally different from a commercial wastewater injection well and entails a much lower risk to USDW. We believe the proposed approach is appropriate and fully protective of USDW for the following reasons:

- The proposed 4,720 feet of 9-5/8-inch long string casing will be cemented to surface and will isolate and protect USDW throughout its full vertical extent (approximately 3000 feet). A radial cement bond log will be run after completion of the cementing operation (Attachment P).
- After the well completion, Mechanical Integrity Tests will be performed to insure the integrity of 9-5/8" casing (Attachment P).
- All the air injection and production will be performed through a string of tubing which will be isolated from the 9-5/8-inch casing by a packer (Attachment M). The annulus between tubing and 9-5/8-inch casing will be pressurized and will be monitored on a continuous basis for leaks (Attachment P), providing a second verified layer of protection.
- This well is proposed to be used for a short-term pilot test for no more than approximately 90 days. The chance of well failure during this period is extremely small.

- The pilot testing program has been amended to significantly decrease both the injection rate and final volume, resulting in a considerable reduction in the anticipated pressure buildup.
- Pressures induced in the reservoir during the proposed compression pilot test will dissipate over time, eliminating the risk of fluid migration. The current reduced pressure state of the depleted gas reservoir will speed the time period over which this occurs.
- The injection gas for this well is air or oxygen-depleted air or ambient air, which are non-hazardous, compressible, and entail a lower risk of USDW contamination than commercial use to inject wastewater.

L.3 INJECTION/WITHDRAWAL WELL INSTALLATION PROGRAM

Detailed drilling, completion, and directional programs for the Injection/Withdrawal Well are included in Attachment L-1. A completion detail schematic of the Injection/Withdrawal Well is included in Attachment M.

Deviation checks will be performed at approximately every 500 vertical feet from 700 feet to 3,465 feet by utilizing the measured while drilling (MWD) method. This will ensure the drill hole does not deviate from the plan beyond acceptable limits.

The wellhead will be equipped with 3,000 psi double master 5-1/8" valves, a 5-1/8" wing valve, and a 2-1/16" 3,000 psi casing valve. The tubing hanger and top flange over the tubing head will be modified so that a ¼" cable can be run through the 5-1/2" tubing hanger and through the top flange of the tubing head. A detailed schematic of the surface completion for the Injection/Withdrawal Well is included in Attachment M-2.

Within 30 days following the installation of the Injection/Withdrawal Well, a well completion report will be provided to the EPA. The report will summarize the drilling, casing and cementing operations. The report will include a detailed driller's report documenting all rig activities will be provided, signed by the Engineer in Charge and the Operator. Complete logs will be appended to the report.

L.4 PIACENTINE 1-27 CONVERSION PROGRAM

Piacentine 1-27 will be converted to a monitoring well prior to formation testing. Conversion will include drilling out the existing cement plug and installing a tubing and packer system with a pressurized annulus. A detailed conversion program for Piacentine 1-27 is included in Attachment L-2. A well completion detail for the conversion is included as Attachment M-3. A report documenting these activities, similar to that described for the Injection/Withdrawal Well, will be provided to EPA within 30 days after completion of the work.

IRANI ENGINEERING
PETROLEUM ENGINEER
2625 FAIR OAKS BLVD., SUITE 10
SACRAMENTO, CALIFORNIA 95864
916-482-2877
FAX 916-482-7514

PG&E

King Island Injection/withdrawal Test Well No. 1

Location: Section 27, T 3N, R 5E, MDB&M San Joaquin County, California.
X=1734880.641 Y= 577346.753 (NAD 27, Zone III)
Elevation: -3.75' ground. +8.25' KB (NGVD 29)

Take all measurements from KB which is 12' above ground.
Keep hole full at all times.
Comply with Standing Orders attached.

Drilling and Completion Program (Drill Pipe: 4-1/2", 16.6#, XH)
Building Location, Set Conductor, Rat Hole, Mouse Hole

1. 8' X 8' cellar will be constructed. Rat hole and mouse hole for the rig will be dug by a water well driller.

2. 20", 53#, 0.25" wall thickness, ERW conductor pipe be cemented at 60' using a water well driller.

Rig Move, Drill 17-1/2" hole to ~600'+, Cement 13-3/8" surface casing, Install BOE.

1. Move in drilling rig. Rig up. Install riser and flow line on 20" conductor. Install mud cleaners and centrifuge. Have a full water tank before spud. In addition have a 500 bbl water tank on location and fill it with water.

2. Run 17-1/2" rental bit, 4-16/32" jets, 2 DC, 17-1/2" Stab, and HW's and drill to 600'+. Use both pumps with 6" liners.

3. Run DIL/SP/GR/Caliper logs

4. Install mud loggers at shoe of conductor around 60'.

Cementing program for 13-3/8" surface casing.

1. Give cementers 24 hour notice. Cement 13-3/8", 54.5#, J-55, New casing at ~600' with 290 sacks Woodland Light cement (Class G, 13.1#, 1.716 cf/sk)followed with 150 sacks Woodland tail cement (Class G, 14.5#, 1.423 cf/sk). Tack weld and Bakerlok bottom 4 collars, weld shoe solid. Run float shoe and insert 40' above shoe. Run centralizer 15', 40' and 80' above shoe. Use top rubber plug only and plug holding head. Bump plug on insert with water. Pressure test to 500 psig. If necessary perform 80 sacks top job cement with 3% CaCl2 (top job will be performed if cement level drops in the annulus)
Note: The cement volume is calculated at 70% excess.

2. After 4 hours WOC, land 13-3/8" casing head (have welders on the hook). Test weld to 500 psig. Install Series 900 (3000#) dual hydraulic control gate and Hydril GK. Test according to Standing Orders. Notify EPA and, if EPA requires, Notify DOGGR to witness. Pressure test casing to 1000 psig. Use Recorded chart for BOE and casing test.

December 30, 2013

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Drill out 13-3/8" casing shoe, drill 12-1/4" hole to 30' above Mokelumne River Formation Sand (Top of sand is estimated to be at 4681' VD)

1. Drill out the shoe of 13-3/8" casing with the following BHA: 12-1/4" long tooth bit with 4-16/32" for jets (a very good used or retip bit), 2 DC's, 12-1/4" stab, 3 HW's, jars, 27 HW's. Use both pumps with 6" liners. Drill to 3465' (~KOP).

2. Run MM, MWD and the following directional BHA: 12-1/4" new long tooth bit with 4-14/32" for jets, 8" MM, 12" stab, float sub, 6-3/4" mule shoe sub (MWD), 6-3/4" monel, 12" stab, 6-3/4", X-over, 3 HW's, jars, 27 Hw's, 4-1/2" DP. Use both pumps with 6" liners.

3. Determine deviation of the wellbore from surface to 3465' by using MWD to take surveys every 500' from 700' to 3465'. Prepare a deviation survey and modify the directional program accordingly. Directionally drill 12-1/4" hole to around 4700' MD (4653' VD) or ~28' above Mokelumne River Formation Sand based on the field geologist. Prepare deviation survey for the entire wellbore. POH. Lay down directional tools.

3. Wipe hole every 6 to 8 hours.

4. Mud sweep should be used to clean hole before pulling out of hole.

5. Have additional 12-1/4" mill tooth bit on location.

Reduce hole size to 8-3/4" and drill to TD at 4963' MD = 4900' VD.

1. Pick up the following BHA. 8-3/4" RT mill tooth bit with 4-14's, bit sub, 2DC's, 3 Hw's, Jars, 27 Hw's. Drill 8-3/4" to TD at 4963' MD = 4900' TVD. Use both pumps.

2. Mud weight should be 10 ppg at 4750'.

3. Wipe hole every 6 to 8 hours.

4. Mud sweep should be used to clean hole before pulling out of hole.

Conditioning hole before logging.

1. Wipe 8-3/4" hole from 4963' to 4600' twice.

2. Circulate well at high rate with both pumps for 1+ hours before pulling out to run logs.

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Logging program for 8-3/4" hole, 12-1/4" hole and 13-3/8" casing.

1. Run DIL/Neutron/Density/Micro-Resistivity/SP/GR/Dipole Sonic/RFT/6 arm Caliper. (Dipole sonic will provide both shear and compressional) from 600' to 4963'.

2. Prepare Borehole Profile from Caliper log.

3. Run CBL/GR log over 13-3/8" surface casing.

Equalize a cement plug in open hole from 4963' to 4700'.

1. Run open-ended drill pipe to TD at 4963'.

2. Equalize 120 sacks Class G cement premixed 2% CaCl2, 1.25% Halad 322, 0.1% Super CBL (Cement amount includes 25% excess). POH. WOC for 4 hours.

Run 12-1/4" bit and drill out cement and formation to top of Mokelumne River formation around 4730' MD=4681' VD.

1. Run the following BHA: 12-1/4" RR bit (4-14/32" jets), 2 DC's, Stab., 3HW's, Jars, 27 Hw's, DP. RIH. Treat mud for cement contamination.

2. Drill out cement and formation to top of Mokelumne River Formation sands at ~4730' MD = ~4681' VD (determined from logs). Circulate and condition hole. Use both pumps. POH.

Cleaning hole to run 9-5/8" long string casing.

1. Ream and clean hole to ~4730' with the following BHA before running casing: 12-1/4" RR bit (4-11/32" jets), 12-1/4" hole-opener with 3-11's jets, 6 point 12-1/4" roller reamer, 3 HW's, Jars, 27 Hw's. Use both pumps.

2. Circulate well at high rate with both pumps before pulling out to run 9-5/8" long string casing.

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9-5/8" Long String Casing and Cementing Program

Surface Casing: 13-3/8", 54.5#, J-55 set at ~600'
Hole size: 12-1/4" hole drilled to ~4730' MD (4681' TVD). MW=10 ppg
Note: This is a directional well with maximum inclination angle of ~20°.

1. Run 700' of 9-5/8", 40#, N-80, LT&C, drifted to 8-3/4" on bottom and 4002' of 9-5/8", 40#, J-55, LT&C, drifted to 8-3/4" on top.

2. Run float shoe and float collar. Tack weld & Bakerlok bottom 4 collars (including shoe, and float). Modify last joint in hole so the bottom of casing is as close as possible to 4730' MD.

3. Prepare tally sheets for the casing. E-mail tally to Irani Engineering.

4. Give Cementers 24 hours notice before running casing.

5. Use Tongs to run casing. Run fill-up and circulating tool. Clean threads. Visually inspect casing. Have slip type elevators. Please bring back up on tongs and elevators. Have welder on location while running casing. Have extra LT&C collar on location to weld on top joint if pipe stops off bottom. Have thread lubricant and apply to the casing on the rack.

6. Notify Wellhead company. 9-5/8" tubing head should be 3000# X 3000#.

7. Place 20 double bow spring centralizer on top of first 20 joints in hole and one bow centralizer on top of each joint after that all the way to 600' (total of 103 centralizers).

8. The cement top is calculated to be at surface.

9. Run long string casing to desired depth. Rig up cementing head with top plug in it. Have two lines to cementing head. Have 2 Elite pump trucks on location. Circulate casing clean. Do not work pipe.

10. Displace cement with fresh water. Have 4 vacuum trucks full of water on location. Mix and pump cement with 2 pump trucks (at least 8 bbl/min). Displace cement with 2 pump trucks (at least 18+ bbl/min).

11. Cement Mix: Pump 40 Bbl of mud flush ahead and cement casing shoe at ~4730' MD with 980 sacks Light Cement premixed with 3% KCl, 0.4% Halad-322, 0.25 lb/sk Pheno Seal, 0.1% FWCA, 0.3% HR-7 (12.8 ppg, 1.48 Cf/sk, 7.63 gal water/sk), followed with 350 sacks Premium Cement premixed with 5% NaCl, 1.25% Halad-322, 0.5% Halad-344, 0.25 lb/sk Pheno Seal, 0.5% D-Air, 0.2% SuperCBL, (15.8 ppg, 1.18 Cf/sk, 4.92 gal water/sk). Ramp up cement density for the tail cement from 15.8 ppg to 16.2 ppg. Launch top plug. Displace with fresh water with 2 pump trucks as fast as possible (~18+ bbl/min). Bump top plug. Test casing to 3000 psig. Use two vacuum trucks for displacement (total displacement volume is ~355 bbls).
    Note: The cement calculation is based on theoretical annulus volume plus 25%. The final cement volume will be based on Caliper log plus 20%.

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Install BOE. Run casing logs. Test BOE.

1. Wait on cement for 8 hours. Remove BOE. Set slip and packing. Cut casing. Install 9-5/8" tubing head (3000#). Install 3000# BOE.

2. After 20 hours WOC. Run 8-3/4" Retip bit and scraper to the top of cement. Do not drill out top plug. POH. Run Segmented (Radial) Bond Log/NL/GR logs. Be prepared to pressure up to 1500 psi. Test BOE and casing to 2500 psig according to standing orders. Notify EPA to witness. Use Recorded chart for BOE and casing Test. Redo the test if the pressure drops more than 5%. Run a 8-3/4" rental retip bit with 4-11/32" jets, 2DC's, Stab, 3 Hw's, jars, 27 Hw's and 4-1/2" DP. Drill out float collar and clean hole to top of shoe. Change hole to clean 4% KCL water treated with polymer.

Dill out shoe of 9-5/8" long string casing. Drill 10' into formation as directed. Prepare to perform SRT.

1. Drill out shoe of 9-5/8" long string casing. Drill 10' into Mokelumne formation as directed with 4% KCl water treated with polymer Circulate hole and change hole to clean 4% KCl water. Store 4% KCl water treated with polymer in a separate tank for future use. Pull out.

2. Run open-ended drill pipe to 4700'- MD. Close pipe rams and bag. Install circulating head with a 2" wing valve and 2" top valve.

3. Rig up Wireline truck. Install lubricator on top of circulating head. Run digital pressure/temperature gauge with Surface reading inside drill pipe to 5' below the top of Mokelumne Formation around 4735' MD.

4. Have 1000+ bbls of clean filtered 4% KCl water available on location in Baker Tanks. Measure the weight of the fluid in PPG. Also measure the fluid viscosity.

5. Before the start of the SRT test make sure the hole is full with 4% KCl water. Record stabilized bottom hole pressure for 1/2 hour.

6. Move in two Halliburton pump trucks. Connect to drill pipe.

Perform SRT

1. Start the Step Rate Test

   Step No. 1: pump at 2 bbls/minute rate, pump at constant rate for 30 min. and record surface and bottom hole pressures.

   Step No. 2: Increase rate by 2 bbl/min. Pump at constant rate for 30 min., record surface and bottom hole pressures.

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Step No. 3: Increase rate by 2 bbl/min. Pump at constant rate for 30 min., record surface and bottom hole pressures.

Subsequent Steps: Increase rate by 2 bbl/min for each step. Pump at constant rate for 30 min., record surface and bottom hole pressures. It is anticipated that approximately six to seven steps may be needed to meet the test objectives

2. Plot the injection rates and pressures and evaluate the data in accordance with SPE Paper 16798 to determine the fracture pressure based on a break in slope. Continue additional rate steps until at least two, and preferably three, rate steps plot past the break in slope. If a break in slope is not evident, continue the test as long as is feasible and until a bottom hole pressure of at least 3200 psi is reached.

3. The size and duration of the rate steps may be adjusted as directed by the engineer and approved by EPA in order to meet the test objectives.

4. If possible, maintain the final rate step for at least 60 minutes in order to prepare for fall off pressure measurement. After the pumping period is completed, shut in the well for 12 hours before retrieving the pressure gauge.

5. Pull out drill pipe.

Run Drilling BHA and drill 8-3/4" hole to ~4772' MD = 4721' TVD

1. Run a 8-3/4" rental retip bit with 4-11/32" jets, 2DC's, Stab, 3 Hw's, jars, 27 Hw's and 4-1/2" DP. Using 4% KCl water treated with polymer drill to ~4772' MD = 4721' VD (40' vertical depth below top of Mokelumne Formation)

2. Wipe hole three times to above float collar. Circulate on bottom for at least 1 hour. POOH.

Under Reaming and logging Program for 17" open hole.

1. Run an under-reamer and under ream the open hole to 17" from 4730' MD to 4772' MD.

2. Re-ream the hole three more times. Circulate on bottom at least for 2 hours. POOH.

3. Run bore hole caliper log from 4730' MD to 4772' MD.

Mud logging Program

1. Install mud loggers at shoe of conductor pipe ~60'. Circulate as necessary for evaluation. Open hole tests will not be run. Take one set W&D samples every 30'. E-mail daily log copies to PG&E, WorleyParsons, EPA, and Irani. Watch pit level monitor closely at all times. Keep 3 spliced log copies in trailer.

December 30, 2013

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Mud Program

Aquagel/Polyac Plus mud system with low PH from 600' to TD.

Depth	Weight	Viscosity	Water Loss
0'- 600'	Spud mud	65 sec.	NC
600'-3000'	9.0-9.8 ppg.	35-45 sec.	6cc/30 min
3000'- TD	9.8-10.0 ppg.	35-45 sec.	6cc/30 min

Have sufficient mud material on location to raise mud weight .66 ppg. Adjust mud weight to maintain mud log base line below 30 units and to stabilize shale.

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PG&E

King Island Test Well No. 1

Gravel Pack & Liner Program

TD ~4772' MD (4721' VD)
Surface Casing: 13-3/8", 54.5#, J-55, cemented at ~600'.
Long String Casing: 9-5/8" 40# J-55 & N-80 cemented at ~4730' MD.
Open Hole: 17" open hole, MW=8.4 ppg 4% KCl water
Drill Pipe: 4-1/2", 16.6#, XH

1. Circulate clean. Pull to shoe. Wait one hour. Run in hole and check for fill.
2. Pull up to 100' above the shoe of the 9-5/8" casing. Rig up Baker DE Filtering Unit. Change hole over to clean filtered 4% KCL water.
3. Pull out of hole.
4. Pick up liner assembly consisting of:

~5' 5-1/2" Circulating Shoe with open hole centralizer
~57' 5-1/2" (~6" OD) premium wire wrap Screen
~38' 5-1/2" Blank Pipe (1 jt 38')
~35' 9-5/8" Baker SC-1 Gravel Pack Tool with Sliding Sleeve, extensions setting and crossover tool
~135' Tail Pipe and polished stinger for circulating shoe (to be run inside WWS)

Note: Centralize liner every 20'. Minimize the use of pipe dope. Apply to pin end only.

5. Run in with liner assembly on 4-1/2" work string to desired depth around 4772' MD.
6. Rig up pumping equipment and lines.
7. Conduct safety meeting.

December 30, 2013

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8. Test lines to ~5000 psi. Drop ball.

9. Set and test gravel pack tools. Blow ball seat.

10. Using clean filtered 4% KCl, establish and record pump rate and pressure in reverse position.

11. Clean tubing by performing a sand scour. With the crossover tool in the reverse position, pump a 5 bbl slurry of ~2 ppg sand down the work string to the reverse port in the crossover tool. Immediately reverse the slurry out off the work string. Keep pump rate as high as conditions allow. Inspect returns to see what material the scour may have removed from the work string.

12. Establish and record pump rate and pressure in circulating position and circulate hole clean. Un-sting from circulating shoe. Using Baker Gravel Infuser System gravel pack WWS. Begin infusing Baker Low Fine Ottawa Gravel into clean 4% KCl water at ½ lb/gal. Typical pump rates are 4-6 bpm. Once sand clears crossover tool then increase sand loading to maximum of 2 PPG as conditions allow. Continue pumping at this rate and concentration until wellhead pressure begins increasing. Pump rate should be reduced accordingly as well head pressure increases. Once pressure reaches 500 PSI over initial circulating pressure is achieved stop pumps. DO NOT RESTRESS PACK at this time.

13. Close annular BOP and apply 500 PSI to the annulus. Place the crossover tool in the reverse position. Reverse out excess gravel until returns are clean. Monitor and determine the volume of gravel reversed out. To test the gravel pack, lower crossover tool into the circulating position. Circulate at sand out rate and attempt to achieve sand out pressure established earlier. If same sand out pressure cannot be achieved, mix and pump another batch of gravel recommended by pump specialist. Repeat this step until final sand out occurs. POOH with service tools.

14. Have 3 500 bbl Baker Tanks full of clean 4% KCL. water on location during the gravel pack job. Have enough vacuum trucks on location to accomplish all the necessary water hauling.

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PG&E

King Island I/W Test Well No. 1

Tubing Program

1. Pick up 5-1/2", 17#, J-55, LT&C tubing. Pick up Baker seal assembly. X-over, Tendeka SPSRO Gauge Mandrel (4-1/2", 12.6# 41330 L-80 with Vam threads, SPSRO Pressure/Temperature Gauge should be inside Mandrel). Connect 1/4" A825 cable to Mandrel. Run X-Over and the 5-1/2" tubing in hole with 1/4" cable attached to the outside of tubing and affixed to the tubing at every connection with 5-1/2" Cross Coupling Cable Protectors. Run in hole very slowly as not to damage cable. Install tubing hanger on top of tubing. Run 1/4" cable through the designated outlet in the tubing hanger. Secure bottom and top of outlet between cable and and outlet with Swagelok Fittings. Circulate through tubing and add corrosion inhabiting additives and biocide to the fluid. Land tubing hanger and stab into Baker Model SC packer at ~4637'. Install 3000# X-mas tree. There is an outlet through the flange above tubing hanger that the cable will pass through and will be sealed with Swagelok Fittings. Test annulus to 2500 psig to make sure the seal assembly is sealing inside packer. Test tree to 3000 psig.

2. Connect 1/4" cable to Junction Box.

Annulus Mechanical Integrity Test

1. Notify EPA. Pressure test 9-5/8" X 5-1/2" annulus with 2500 psig for 30 minutes. Use recordable pressure gauge for the testing (Halliburton SPIDR Dual crystal quartz gauge is a good option). Install pressure gauges on both tubing and annulus. Monitor tubing and annulus pressures during test. Redo the test if the pressure drops by more than 5%.

December 30, 2013

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PG&E

King Island Injection/Withdrawal Test Well No. 1

Location: X=1734880.641 Y= 577346.753 (NAD 27, Zone III)
Section 27, T 3N, R 5E, San Joaquin County, California.
Elevation: -3.75' ground. +8.25' KB (NGVD 29)

Take all measurements from KB which is 12' above ground.

Present Condition

TD:~4772' MD PD: ~4767' MD
Casing: 13-3/8", 54.5#, J-55 surface casing cemented at 600
9-5/8", 40#, J-55 & N-80 intermediate casing cemented at 4730'.
5-1/2" premium wire wrap liner gravel packed from 4710' to 4772'.
Tubing: 5-1/2", 15.5#, J-55, LT&C, thread with seal assembly stabbed into SC packer at ~4637'.
Note: A downhole permanent pressure gauge is above the seal assembly. There is ¼" cable that runs outside of tubing and it is affixed to the tubing with 5-1/2" Cross Coupling Cable Protectors at every connection. The cable goes through the outlets in the tubing hanger and tubing head top flange and is connected to an instrument junction box at surface.
Note: There is 4% KCL water in tubing. This well is directional with maximum angle of 20 degrees.

Completion Program

1. Install two Baker Tanks (500 bbls each) on location. Install and stake a 3" steel line from the wing valve to a tank.

2. Move in 2-1/2" coil tubing truck on location. Run coil tubing to bottom of hole at around 4767'MD. Using Nitrogen unload completion fluid. Using Nitrogen induce formation water flow. Flow more than 300 Bbl of formation water. Perform field measurements for PH, conductivity, temperature, and TDS. Take 3 formation water samples and send to an EPA approved laboratory and analyze for Trace Metals, Major Anions and Cations, Alkalinity, Conductivity, Hardness, PH, and TDS, Specific Gravity (see II.E.1(a)), and Oil & Grease (per 40 CFR&136.3). The analysis should indicate the recovery of Mokelumne formation water.

3. During the injection/Withdrawal and shut in operations maintain 100 psig pressure (use Nitrogen) on the 9-5/8" X 5-1/2" annulus. Install electronic pressure gauges on both tubing and annulus (5-1/2" X 9-5/8") outlets. Monitor tubing pressure and annulus pressure continuously.

April 4, 2014

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PG&E

King Island I/W Test Well No. 1

Elevation: -3.75' ground, USGS, +8.25' KB.

Anticipated Formation Tops

	Vertical Depth	Measured Depth
Top of Mokelumne River Formation	4681'	4730'
TD	4900'	4964'

December 30, 2013

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STANDING ORDERS, DRILLING & REMEDIAL OPERATIONS

Operator PG&E Well No. King Island I/W Test Well No. 1

Contractor Paul Graham Drilling Rig No. 7

*1. Prior to drilling out the surface casing, the blowout preventers and all associated equipment shall be pressure tested to 50% of the rated working pressure (Bag preventer to 40%). Equipment to be tested separately are: Pipe rams, blind rams, bag preventer, kelly cock, standpipe valve, kill line (stop valve, check valve) and blow down line (each valve, choke and bean). Blow down manifold shall have at least one operating pressure gage of a range at least 1000 psig higher than blowout preventer rated working pressure. EPA to witness.
*2. Blowout preventers on protection and production casing shall be tested as above to 70% of rated pressure (Bag to 50%).
*3. Each drilling crew is to have at least one blowout drill weekly.
*4. Before tripping, check the ditch for flow with pumps off.
*5. Daily record the one-half pump stroke standpipe pressure.
6. Measure drill pipe on first trip after installing mud loggers.
7. All casing run shall be carefully visually inspected for pipe body and thread defects as it is unloaded. Casing shall not be permitted to drop from trucks, roll it off on ramps.
8. Protection and production casing shall be run with hydraulic tongs set to the proper torque for the casing being run. Pick up thread protectors shall be used.
9. All casing shall have threads "bright" cleaned and a Teflon pipe dope (Bakerseal, TF-17) liberally applied.
10. Keep hole full at all times.
*11. Check operation of BOE each round trip.
12. Take all measurements from KB.
13. Drilling rig mud pits shall have a calibrated tank to gage mud used to fill the hole on trips.
14. Have a 1000 psig pressure gauge available on the floor.
15. Company man and tool pusher must sign tour sheet daily and note any downtime. Company man needs to note daily and monthly cumulative downtime on daily report.

Each 60' stand of 4-1/2" drill pipe takes 0.38 barrel.

*Shall be entered on tour sheet and signed by person in responsible charge.
Date: December 07, 2013

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PG&E

King Island Injection/Withdrawal Test Well No. 1

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Section 27, T 3N, R 5E, San Joaquin County, California.
Elevation: -3.75' ground. +8.25' KB (NGVD 29)

Take all measurements from KB which is 12' above ground.

Present Condition

TD:~4772' MD PD: ~4767' MD
Casing: 13-3/8", 54.5#, J-55 surface casing cemented at 600
9-5/8", 40#, J-55 & N-80 intermediate casing cemented at 4730'.
5-1/2" premium wire wrap liner gravel packed from 4710' to 4772'.
Tubing: 5-1/2", 15.5#, J-55, LT&C, thread with seal assembly stabbed into SC packer at ~4637'.
Note: A downhole permanent pressure gauge is above the seal assembly. There is ¼" cable that runs outside of tubing and it is affixed to the tubing with 5-1/2" Cross Coupling Cable Protectors at every connection. The cable goes through the outlets in the tubing hanger and tubing head top flange and is connected to an instrument junction box at surface.
Note: There is 4% KCL water in tubing. This well is directional with maximum angle of 20 degrees.

Completion Program

1. Install two Baker Tanks (500 bbls each) on location. Install and stake a 3" steel line from the wing valve to a tank.

2. Move in 2-1/2" coil tubing truck on location. Run coil tubing to bottom of hole at around 4767'MD. Using Nitrogen unload completion fluid. Using Nitrogen induce formation water flow. Flow more than 300 Bbl of formation water. Perform field measurements for PH, conductivity, temperature, and TDS. Take 3 formation water samples and send to an EPA approved laboratory and analyze for Trace Metals, Major Anions and Cations, Alkalinity, Conductivity, Hardness, PH, and TDS, Specific Gravity (see II.E.1(a)), and Oil & Grease (per 40 CFR&136.3). The analysis should indicate the recovery of Mokelumne formation water.

3. During the injection/Withdrawal and shut in operations maintain 100 psig pressure (use Nitrogen) on the 9-5/8" X 5-1/2" annulus. Install electronic pressure gauges on both tubing and annulus (5-1/2" X 9-5/8") outlets. Monitor tubing pressure and annulus pressure continuously.

April 4, 2014

Pacific Gas & Electric

San Joaquin County
Sec 27, T3N, R5E
_King Island I/W Test Well #1

Wellbore #1

Plan: Plan #2 (31-Oct-13)

Job No. Plan #2 (31-Oct-13)

Sperry Drilling Services

Combo Report

31 October, 2013

Well Coordinates: 577,346.75 N, 1,734,880.64 E (38° 04' 55.48" N, 121° 25' 15.96" W)
Ground Level: -6.00 ft

Local Coordinate Origin:	Centered on Well _King Island I/W Test Well #1
Viewing Datum:	rkbe (p) @ 6.00ft (Original Well Elev)
TVDs to System:	N
North Reference:	Grid
Unit System:	API - US Survey Feet

Version: 2003.14 Build: 82

HALLIBURTON

Plan Report for _King Island I/W Test Well #1 - Plan #2 (31-Oct-13)

Measured Depth (ft)	Inclination (°)	Azimuth (°)	TVD below System (ft)	Vertical Depth (ft)	Local Coordinates Northing (ft)	Local Coordinates Easting (ft)	Map Coordinates Northing (ft)	Map Coordinates Easting (ft)	Dogleg Rate (°/100ft)	Vertical Section (ft)	Comments
0.00	0.00	0.00	6.00	0.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
6.00	0.00	0.00	0.00	6.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	GL
100.00	0.00	0.00	-94.00	100.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
200.00	0.00	0.00	-194.00	200.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
300.00	0.00	0.00	-294.00	300.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
400.00	0.00	0.00	-394.00	400.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
500.00	0.00	0.00	-494.00	500.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
600.00	0.00	0.00	-594.00	600.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
700.00	0.00	0.00	-694.00	700.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
800.00	0.00	0.00	-794.00	800.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
900.00	0.00	0.00	-894.00	900.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,000.00	0.00	0.00	-994.00	1,000.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,100.00	0.00	0.00	-1,094.00	1,100.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,200.00	0.00	0.00	-1,194.00	1,200.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,300.00	0.00	0.00	-1,294.00	1,300.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,400.00	0.00	0.00	-1,394.00	1,400.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,500.00	0.00	0.00	-1,494.00	1,500.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,600.00	0.00	0.00	-1,594.00	1,600.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,700.00	0.00	0.00	-1,694.00	1,700.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,800.00	0.00	0.00	-1,794.00	1,800.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
1,900.00	0.00	0.00	-1,894.00	1,900.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,000.00	0.00	0.00	-1,994.00	2,000.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,100.00	0.00	0.00	-2,094.00	2,100.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,200.00	0.00	0.00	-2,194.00	2,200.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,300.00	0.00	0.00	-2,294.00	2,300.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,400.00	0.00	0.00	-2,394.00	2,400.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,500.00	0.00	0.00	-2,494.00	2,500.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,600.00	0.00	0.00	-2,594.00	2,600.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,700.00	0.00	0.00	-2,694.00	2,700.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,800.00	0.00	0.00	-2,794.00	2,800.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
2,900.00	0.00	0.00	-2,894.00	2,900.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
3,000.00	0.00	0.00	-2,994.00	3,000.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
3,100.00	0.00	0.00	-3,094.00	3,100.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
3,200.00	0.00	0.00	-3,194.00	3,200.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
3,300.00	0.00	0.00	-3,294.00	3,300.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
3,400.00	0.00	0.00	-3,394.00	3,400.00	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	
3,464.95	0.00	0.00	-3,458.95	3,464.95	0.00 N	0.00 E	577,346.75	1,734,880.64	0.00	0.00	Start Build 3.00
3,500.00	1.05	40.18	-3,494.00	3,500.00	0.25 N	0.21 E	577,347.00	1,734,880.85	3.00	0.32	
3,600.00	4.05	40.18	-3,593.89	3,599.89	3.65 N	3.08 E	577,350.40	1,734,883.72	3.00	4.77	
3,700.00	7.05	40.18	-3,693.41	3,699.41	11.04 N	9.32 E	577,357.79	1,734,889.96	3.00	14.45	

HALLIBURTON

Plan Report for _King Island I/W Test Well #1 - Plan #2 (31-Oct-13)

Measured Depth (ft)	Inclination (°)	Azimuth (°)	TVD below System (ft)	Vertical Depth (ft)	Local Coordinates Northing (ft)	Local Coordinates Easting (ft)	Map Coordinates Northing (ft)	Map Coordinates Easting (ft)	Dogleg Rate (°/100ft)	Vertical Section (ft)	Comments
3,800.00	10.05	40.18	-3,792.28	3,798.28	22.40 N	18.91 E	577,369.15	1,734,899.55	3.00	29.31	
3,900.00	13.05	40.18	-3,890.25	3,896.25	37.69 N	31.83 E	577,384.45	1,734,912.47	3.00	49.34	
4,000.00	16.05	40.18	-3,987.03	3,993.03	56.89 N	48.04 E	577,403.64	1,734,928.68	3.00	74.46	
4,100.00	19.05	40.18	-4,082.36	4,088.36	79.92 N	67.49 E	577,426.68	1,734,948.14	3.00	104.61	
4,131.62	20.00	40.18	-4,112.17	4,118.17	88.00 N	74.31 E	577,434.75	1,734,954.95	3.00	115.18	Start 598.96 hold at 4131.62 MD
4,200.00	20.00	40.18	-4,176.42	4,182.42	105.87 N	89.40 E	577,452.62	1,734,970.04	0.00	138.57	
4,300.00	20.00	40.18	-4,270.39	4,276.39	132.00 N	111.47 E	577,478.75	1,734,992.11	0.00	172.77	
4,400.00	20.00	40.18	-4,364.36	4,370.36	158.13 N	133.54 E	577,504.88	1,735,014.18	0.00	206.97	
4,500.00	20.00	40.18	-4,458.33	4,464.33	184.26 N	155.60 E	577,531.01	1,735,036.25	0.00	241.17	
4,600.00	20.00	40.18	-4,552.30	4,558.30	210.39 N	177.67 E	577,557.14	1,735,058.31	0.00	275.37	
4,700.00	20.00	40.18	-4,646.27	4,652.27	236.52 N	199.74 E	577,583.27	1,735,080.38	0.00	309.58	
4,730.58	20.00	40.18	-4,675.00	4,681.00	244.51 N	206.49 E	577,591.26	1,735,087.13	0.00	320.03	Start 233.05 hold at 4730.58 MD - King Island I/W T1
4,800.00	20.00	40.18	-4,740.24	4,746.24	262.65 N	221.81 E	577,609.40	1,735,102.45	0.00	343.78	
4,844.44	20.00	40.18	-4,782.00	4,788.00	274.26 N	231.61 E	577,621.02	1,735,112.25	0.00	358.98	Gas/Water
4,900.00	20.00	40.18	-4,834.20	4,840.20	288.78 N	243.87 E	577,635.53	1,735,124.51	0.00	377.98	
4,963.63	20.00	40.18	-4,894.00	4,900.00	305.41 N	257.91 E	577,652.16	1,735,138.56	0.00	399.74	TD at 4963.63

Plan Annotations

Measured Depth (ft)	Vertical Depth (ft)	Local Coordinates +N/-S (ft)	Local Coordinates +E/-W (ft)	Comment
6.00	6.00	0.00	0.00	GL
3,464.95	3,464.95	0.00	0.00	Start Build 3.00
4,131.62	4,118.17	88.00	74.31	Start 598.96 hold at 4131.62 MD
4,730.58	4,681.00	244.51	206.49	Start 233.05 hold at 4730.58 MD
4,963.63	4,900.00	305.41	257.91	TD at 4963.63

Vertical Section Information

Angle Type	Target	Azimuth (°)	Origin Type	Origin +N/_S (ft)	Origin +E/-W (ft)	Start TVD (ft)
TD	No Target (Freehand)	40.18	Slot	0.00	0.00	0.00

Plan Report for _King Island I/W Test Well #1 - Plan #2 (31-Oct-13)

Survey tool program

From (ft)	To (ft)	Survey/Plan	Survey Tool
0.00	4,963.63	Plan #2 (31-Oct-13)	MWD ISCWSA

Formation Details

Measured Depth (ft)	Vertical Depth (ft)	TVDSS (ft)	Name	Lithology	Dip (°)	Dip Direction (°)
4,844.44	4,788.00	4,782.00	Gas/Water		0.00	

Targets

Target Name - hit/miss target - Shape	Dip Angle (°)	Dip Dir. (°)	TVD (ft)	+N/-S (ft)	+E/-W (ft)	Northing (ft)	Easting (ft)	Latitude	Longitude
King Island I/W T1 - plan hits target - Point	0.00	360.00	4,681.00	244.51	206.49	577,591.26	1,735,087.13	38.083	-121.420

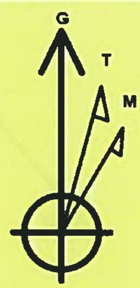
North Reference Sheet for Sec 27, T3N, R5E - _King Island I/W Test Well #1 - Wellbore #1

All data is in US Feet unless otherwise stated. Directions and Coordinates are relative to Grid North Reference.
Vertical Depths are relative to rkbe (p) @ 6.00ft (Original Well Elev). Northing and Easting are relative to _King Island I/W Test Well #1

Coordinate System is US State Plane 1927 (Exact solution), California III 403 using datum NAD 1927 (NADCON CONUS), ellipsoid Clarke 1866
Projection method is Lambert Conformal Conic (2 parallel)
Central Meridian is -120.500°, Longitude Origin 0.000°, Latitude Origin 38.433°
False Easting: 2,000,000.00ft, False Northing: 0.00ft, Scale Reduction: 0.99994582

Grid Coordinates of Well: 577,346.75 ft N, 1,734,880.64 ft E
Geographical Coordinates of Well: 38° 04' 55.46" N, 121° 25' 15.96" W
Grid Convergence at Surface is: -0.56°

Based upon Minimum Curvature type calculations, at a Measured Depth of 4,963.63ft
the Bottom Hole Displacement is 399.74ft in the Direction of 40.18° (Grid).
Magnetic Convergence at surface is: -14.41° (29 October 2013, , IGRF2010)



Magnetic Model:	IGRF2010
Date:	29-Oct-13
Declination:	13.84°
Inclination/Dip:	61.70°
Field Strength:	49081

Grid North is 0.56° West of True North (Grid Convergence)
Magnetic North is 13.84° East of True North (Magnetic Declination)
Magnetic North is 14.41° East of Grid North (Magnetic Convergence)

To convert a True Direction to a Grid Direction, Add 0.56°
To convert a Magnetic Direction to a True Direction, Add 13.84° East
To convert a Magnetic Direction to a Grid Direction, Add 14.41°

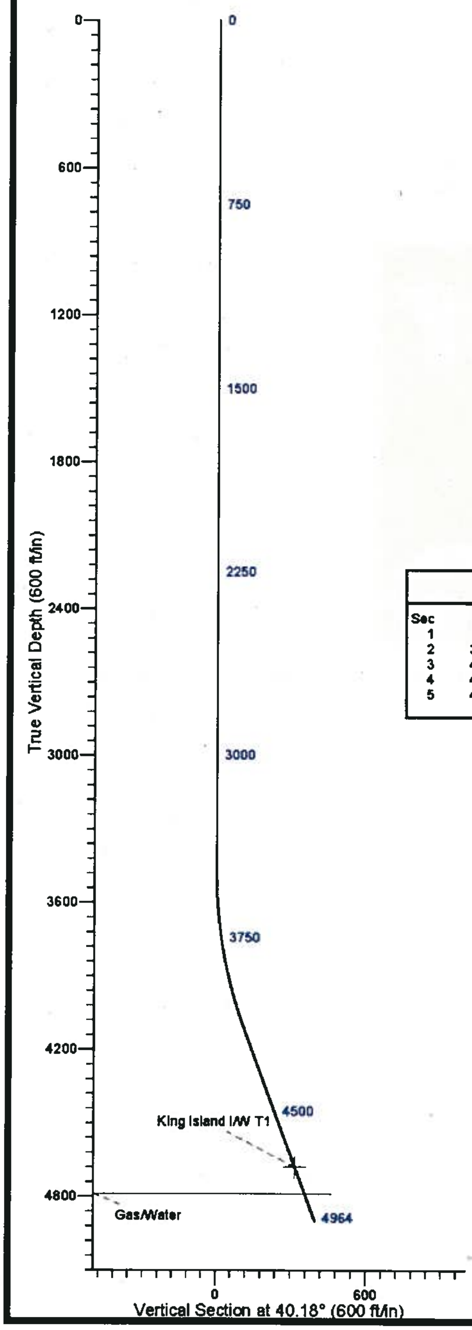
Azimuths to Grid North
True North: 0.56°
Magnetic North: 14.41°

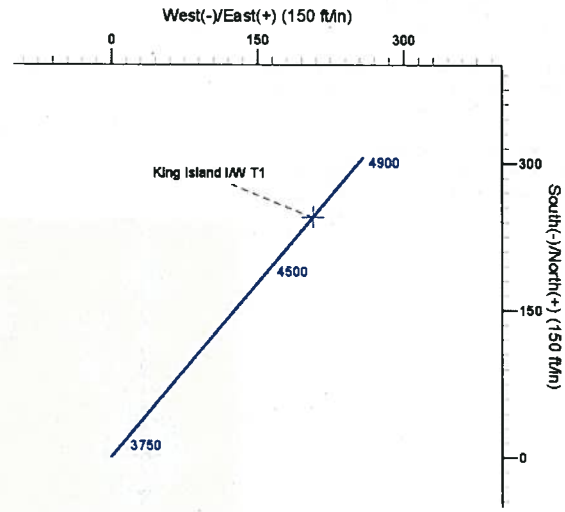
Magnetic Field
Strength: 49080.6nT
Dip Angle: 61.70°
Date: 10/29/2013
Model: IGRF2010

Pacific Gas & Electric

Project: San Joaquin County
Site: Sec 27, T3N, R5E
Well: _King Island I/W Test Well #1
Wellbore: Wellbore #1
Design: Plan #2 (31-Oct-13)

HALLIBURTON
Sperry Drilling





SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Target
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
2	3464.95	0.00	0.00	3464.95	0.00	0.00	0.00	0.00	0.00	
3	4131.62	20.00	40.18	4118.17	88.00	74.31	3.00	40.18	115.18	
4	4730.58	20.00	40.18	4681.00	244.51	206.49	0.00	0.00	320.03	King Island I/W T1
5	4963.63	20.00	40.18	4900.00	305.41	257.91	0.00	0.00	399.74	

_King Island I/W Test Well #1
NAD 1927 (NADCON CONUS)
California III 403
Grid
rkbe (p) @ 6.00ft (Original Well Elev)
Northing: 577346.75
Easting: 1734880.64

Pacific Gas & Electric
_King Island I/W Test Well - Plan #2 (31-Oct-13)r

MD	Inc	Azimuth	TVD	Subsea	Latitude	Northings	Departure	Eastings	Vert Sec	Dogleg
0.00	0.00	0.00	0.00	6.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
100.00	0.00	0.00	100.00	-94.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
200.00	0.00	0.00	200.00	-194.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
300.00	0.00	0.00	300.00	-294.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
400.00	0.00	0.00	400.00	-394.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
500.00	0.00	0.00	500.00	-494.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
600.00	0.00	0.00	600.00	-594.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
700.00	0.00	0.00	700.00	-694.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
800.00	0.00	0.00	800.00	-794.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
900.00	0.00	0.00	900.00	-894.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1000.00	0.00	0.00	1000.00	-994.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1100.00	0.00	0.00	1100.00	-1094.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1200.00	0.00	0.00	1200.00	-1194.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1300.00	0.00	0.00	1300.00	-1294.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1400.00	0.00	0.00	1400.00	-1394.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1500.00	0.00	0.00	1500.00	-1494.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1600.00	0.00	0.00	1600.00	-1594.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1700.00	0.00	0.00	1700.00	-1694.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1800.00	0.00	0.00	1800.00	-1794.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
1900.00	0.00	0.00	1900.00	-1894.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2000.00	0.00	0.00	2000.00	-1994.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2100.00	0.00	0.00	2100.00	-2094.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2200.00	0.00	0.00	2200.00	-2194.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2300.00	0.00	0.00	2300.00	-2294.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2400.00	0.00	0.00	2400.00	-2394.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2500.00	0.00	0.00	2500.00	-2494.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2600.00	0.00	0.00	2600.00	-2594.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2700.00	0.00	0.00	2700.00	-2694.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2800.00	0.00	0.00	2800.00	-2794.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
2900.00	0.00	0.00	2900.00	-2894.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
3000.00	0.00	0.00	3000.00	-2994.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
3100.00	0.00	0.00	3100.00	-3094.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
3200.00	0.00	0.00	3200.00	-3194.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
3300.00	0.00	0.00	3300.00	-3294.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
3400.00	0.00	0.00	3400.00	-3394.00	0.00	577346.75	0.00	1734880.64	0.00	0.00
3464.95	0.00	0.00	3464.95	-3458.95	0.00	577346.75	0.00	1734880.64	0.00	0.00
3500.00	1.05	40.18	3500.00	-3494.00	0.25	577347.00	0.21	1734880.85	0.32	3.00
3600.00	4.05	40.18	3599.89	-3593.89	3.65	577350.40	3.08	1734883.72	4.77	3.00
3700.00	7.05	40.18	3699.41	-3693.41	11.04	577357.79	9.32	1734889.96	14.45	3.00
3800.00	10.05	40.18	3798.28	-3792.28	22.40	577369.15	18.91	1734899.55	29.31	3.00
3900.00	13.05	40.18	3896.25	-3890.25	37.69	577384.45	31.83	1734912.47	49.34	3.00
4000.00	16.05	40.18	3993.03	-3987.03	56.89	577403.64	48.04	1734928.68	74.46	3.00
4100.00	19.05	40.18	4088.36	-4082.36	79.92	577426.68	67.49	1734948.14	104.61	3.00
4131.62	20.00	40.18	4118.17	-4112.17	88.00	577434.75	74.31	1734954.95	115.18	3.00
4200.00	20.00	40.18	4182.42	-4176.42	105.87	577452.62	89.40	1734970.04	138.57	0.00
4300.00	20.00	40.18	4276.39	-4270.39	132.00	577478.75	111.47	1734992.11	172.77	0.00
4400.00	20.00	40.18	4370.36	-4364.36	158.13	577504.88	133.54	1735014.18	206.97	0.00
4500.00	20.00	40.18	4464.33	-4458.33	184.26	577531.01	155.60	1735036.25	241.17	0.00
4600.00	20.00	40.18	4558.30	-4552.30	210.39	577557.14	177.67	1735058.31	275.37	0.00
4700.00	20.00	40.18	4652.27	-4646.27	236.52	577583.27	199.74	1735080.38	309.58	0.00

4730.58	20.00	40.18	4681.00	-4675.00	244.51	577591.26	206.49	1735087.13	320.03	0.00
4800.00	20.00	40.18	4746.24	-4740.24	262.65	577609.40	221.81	1735102.45	343.78	0.00
4900.00	20.00	40.18	4840.20	-4834.20	288.78	577635.53	243.87	1735124.51	377.98	0.00
4963.63	20.00	40.18	4900.00	-4894.00	305.41	577652.16	257.91	1735138.56	399.74	0.00

IRANI ENGINEERING, INC.
PETROLEUM ENGINEER
2625 FAIR OAKS BOULEVARD, SUITE 10
SACRAMENTO, CALIFORNIA 95864
916-482-2847
FAX 916-482-7514

Princeton Natural Gas, LLC

Piacentine No. 1-27

Location: 3490' North and 990' East from southwest corner of
Section 27, T 3N, R 5E, MDB&M, San Joaquin Co., California.
Elevation: -6' ground, USGS. +7' KB.

Take all measurements from KB which is 13' above ground.
Keep hole full at all times.
Check operation of BOE daily

Present Condition (Producing)

TD 4900' MD PD: 4715' (bridge plug)
Casing: 8-5/8", 24#, J-55, cemented to surface @ 627'.
5-1/2", 15.5#, K-55, cemented at 4900'. Top of cement in the annulus is at 4175'.
Tubing: 2-3/8", 4.7#, J-55, EUE tubing hung at 4587'
Perforations: 4670'-4682'. Open
4684'-4690', 4700'-4705'. Cement squeezed.
4720'-4724', 4750'-4764'. Cement squeezed, Below bridge plug at 4715'.
Base of freshwater: ~150' (per Division of Oil & Gas).

Conversion program to an observation well

1. Move in workover rig. Kill well with 4% KCl water treated with polymer. Install BOE and test. Notify EPA to witness, and if EPA requires, notify DOG to witness. Pressure test BOE to 2500 psig for 1 hour. Use recorded Chart for BOE test.
2. Pull out with tubing. Run 4-3/4" mill, 4 3" DC's, on bottom of tubing. Run in hole to top of Bridge plug at 4715'. Rig up power swivel. Mill out bridge plug. Mill out cement plug from 4740' to 4764'. Clean out hole to 4850'. Reverse hole clean. Pull out.
3. Run mill and scraper to 4850'. Reverse hole clean. Pull out.
4. Run TMD (pulse Neutron)/GR/Collar located log from 4500' to 4830'.
5. Run Model R packer on bottom of tubing with Model R nipple above the Packer and a re-entry sub below the packer. Set packer at 4650'. Pressure test annulus to 2500 psig for 1 hour. Use recorded chart for this test. Notify EPA to witness.
6. Install X-mas tree. Test tree to 3000 psig.
7. Install pressure and temperature gauges on both tubing and casing sides.
8. Pressurize the annulus with 100 psig nitrogen. Monitor tubing and casing pressures on continuous bases.
9. Turn well over to operator as an observation well.

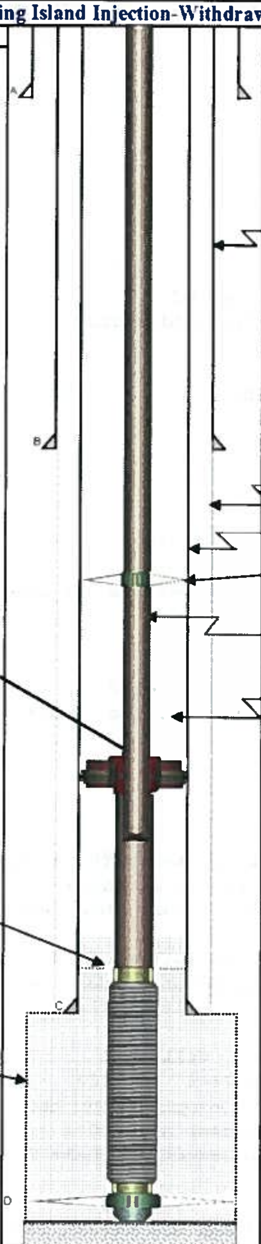
1/1/2014

Injection / Test Well

King Island Injection-Withdrawal Test Well No. 1

COMMENTS

EQUIPMENT DESCRIPTION



PBTD	4772'	MD	4721'	TVD
TD	4772'	MD	4721'	TVD

PG&E
WELL COMPLETION DIAGRAM

FIELD	NA		
WELL #	King Island Test Well No. 1		
Ground MSL -ft	-3.75		
KB	8.29'		
LOCATION	Sec. 27, T 3N, R 5E, MDB&M		

DIRECTIONAL DATA			
MAX ANGLE	20	THRU ZONE	4772'
KOP	3465'	HOLE TYPE	Directional
BH Location	Vertical	255' N & 215' E	

SURFACE EQUIPMENT	
TREE	3" 3M
SWAB CAP SIZE & THRD	8rd EUE lift thread
TOP TREE FLANGE	5" 3M
TUBING SPOOL FLANGE	11" 3M

TUBING DETAIL	1st or LS	SS or Btm of Taper
SIZE	5-1/2"	
WEIGHT	15.5#	
GRADE	J-55	
DEPTH	4637'	
THREAD	LT&C	
NEW/USED	NEW	
COATING	None	
SCSSV	None	
Min. ID	4.825"	

	O.D. (in.)	I.D. (in.)	LENGTH (ft)	DESCRIPTION
1	5-1/2"	4.825"	4637'	5-1/2", 15.5#, J-55
2	8"	5"	5'	Baker SC-1 Packer
3	5.5"	4.892	6'	Upper Extension
4	5.81"	4.892	2'	Baker Model S Sliding Sleeve
5	5.56"	4.892	1'	Baker Seal Bore
6	5.56"	4.892"	17'	Lower Extension
7	5.5"	4.892	38'	Blank 5-1/2", 17#, N-80
8	6"	4.892	62'	51/2" Wire wraped screen
9	5.5"	1.813"	2.71	O-ring seal sub
10	5.5"	N/A	1.80	shoe
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				

CASING DETAIL

#	SIZE	WGHT	GRADE	THRD	DEPTH (MD)
A	20"	53#	NA		0' - 60'
B	13-3/8"	54.5	J-55	LT&C	0' - 600'
C	9-5/8""	40#	J&N	LT&C	0' - 4,730'
D	5-1/2"	17#	N-80	LT&C	4637'-4772'
E					
F					
G					
H					
I					
J					
K					
L					
M					
N					

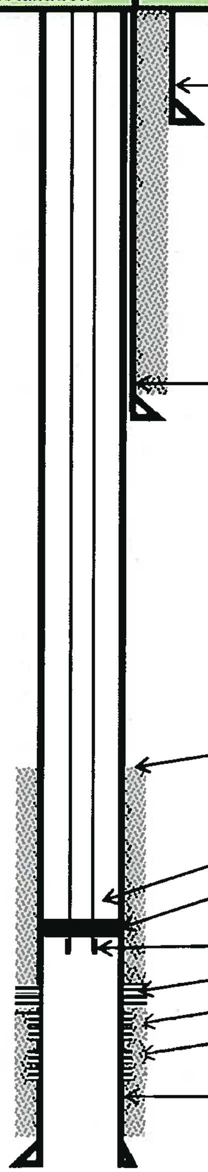
Prepared By	Saeed Irani	Date	Nov. 11, 2013
Updated By	Saeed Irani	Date	November 21, 2013
		Printed on	January 4, 2014

Completed

File
J:\Project Active\WorleyParsons PGE CAES\SOPO 1.4 Task 3.7.4 Core Well UIC Permitting\UIC Application Report\December 2013\Attachment M - Construction Details\[Alt M-1 Test Well No. 1 Schematic 21-Nov-13.xls]Actual WBD

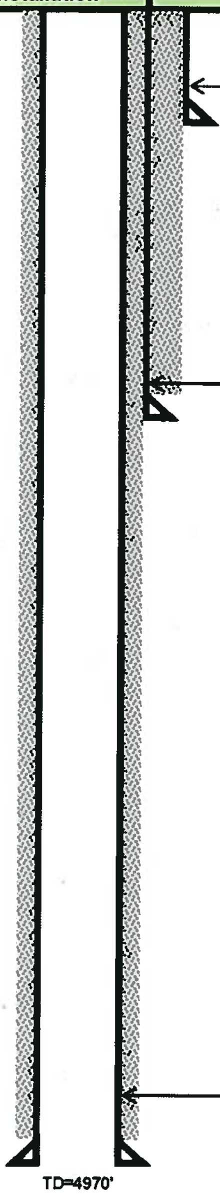
Piacentine 1-27 (API No. 077-20484) Construction Details
San Joaquin, California
Sec 27, T 3N, R 5E

Location: Section 27, T 3N, R 5E, San Joaquin, California.
Elevation: -6' ground, +7' KB. All the measurements are from KB which is 13' above ground.

Installation		Depth & Description (after Planned Completion)	OD	ID
		16" Conductor Set at 40'		
		8-5/8", 24# J-55 Casing at 627' (Cemented to Surface)	8-5/8"	8.097"
		Top of cement in annlus is 4175'.		
		2-3/8", 4.7#, J-55 EUE tubing		
		Model R Packer at 4650' with a nipple.		
		Re-entry sub		
		Perforations from 4670'-4682'.		
		Perforations from 4684'-4690', 4700'-4705'. Cement squeezed		
		Perforations from 4720'-4724', 4750'-4764'. Cement squeezed		
		5-1/2", 15.5#, K-55, LT&C Casing set at 4900'	5-1/2"	4.950"
PD=4850' TD=4900'				

Piacentine 2-27 (API No. 077-20736)
San Joaquin, California
Sec 27, T 3N, R 5E

Location: Section 27, T 3N, R 5E, San Joaquin, California.
Elevation & KB (12'): +6'



Installation		Depth & Description (after Planned Completion)	OD	ID
		Conductor at 60'		
		9-5/8", 36# J-55 STC Casing at 614' (12-1/4" hole) (Cemented to Surface with 280 Sacks)	9-5/8"	8.921"
		5-1/2", 15.5#, J-55, LT&C Casing set at 4969' (Cemented to Surface with 1180 Sacks)	5-1/2"	4.950"

Irani Engineering 1/2?/2013

APPENDIX C – EPA Reporting Forms

Form 7520-7	Application to Transfer Permit
Form 7520-9	Completion of Construction
Form 7520-11	Annual Well Monitoring Report
Form 75200-12	Well Rework Record
Form 7520-14	Plugging and Abandonment Plan(s)

APPENDIX D – Logging Requirements

Region 9 Temperature Logging Requirements

A Temperature "Decay" Log (two separate temperature logging passes) must satisfy the following criteria to be considered a valid MIT as specified by 40 CFR §146.8(c) (1). Variances to these requirements are expected for certain circumstances, but they must be approved prior to running the log. As a general rule, the well shall inject for approximately six (6) months prior to running a temperature decay progression sequence of logs.

1. With the printed log, also provide raw data for both logging runs (at least one data reading per foot depth) unless the logging truck is equipped with an analog panel as the processing device.
2. The heading on the log must be complete and include all the pertinent information, such as correct well name, location, elevations, etc.
3. The total shut-in times must be clearly shown in the heading. Minimum shut-in time for active injectors is twelve (12) hours for running the initial temperature log, followed by a second log, a minimum of four (4) hours later. These two log runs will be superimposed on the same track for final presentation.
4. The logging speed must be kept between twenty (20) and fifty (50) feet per minute (30 ft/min optimum) for both logs. The temperature sensor should be located as close to the bottom of the tool string as possible (logging downhole).
5. The vertical depth scale of the log should be one (1) or two (2) inches per one-hundred (100) feet to match lithology logs (see 7(b)). The horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.
6. The right hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.
7. The left hand tracks must contain (unless impractical, but EPA must pre-approve any deviations):
    - (a) a collar locator log,
    - (b) a lithology log which includes either:
        - (i) an historic Gamma Ray that is "readable", i.e. one that demonstrates lithologic changes without either excessive activity by the needle or severely dampened responses; or
        - (ii) a copy of an original spontaneous potential (SP) curve from either the subject well or from a representative, nearby well.
    - (c) A clear identification on the log showing the base of the lowermost Underground Source of Drinking Water (USDW). A USDW is basically a formation that contains less than ten thousand (10,000) parts per million (ppm) Total Dissolved Solids (TDS) and is further defined in 40 CFR §144.3.

EPA Region 9
UIC PRESSURE FALLOFF REQUIREMENTS

Condensed version of the
EPA Region 6

UIC PRESSURE FALLOFF TESTING GUIDELINE

Third Revision

August 8, 2002

TABLE OF CONTENTS

APPENDIX

REQUIREMENTS

UIC PRESSURE FALLOFF TESTING GUIDELINE
Third Revision
August 8, 2002

1.0 Background

Region 9 has adopted the Region 6 UIC Pressure Falloff Testing Guideline requirements for monitoring Class 1 Non Hazardous waste disposal wells. Under 40 CFR 146.13(d)(1), operators are required annually to monitor the pressure buildup in the injection zone, including at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

All of the following parameters (Test, Period, Analysis) are critical for evaluation of technical adequacy of UIC permits:

A falloff **test** is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. The falloff **period** is a replay of the injection preceding it; consequently, it is impacted by the magnitude, length, and rate fluctuations of the injection period. Falloff testing **analysis** provides transmissibility, skin factor, and well flowing and static pressures.

2.0 Purpose of Guideline

This guideline has been adopted by the Region 9 office of the Evironmental Protection Agency (EPA) to assist operators in **planning and conducting** the falloff test and preparing the **annual monitoring report**.

Falloff tests provide reservoir pressure data and characterize both the injection interval reservoir and the completion condition of the injection well. Both the reservoir parameters and pressure data are necessary for UIC permit demonstrations. Additionally, a valid falloff test is a monitoring requirement under 40 CFR Part 146 for all Class I injection wells.

The ultimate responsibility of conducting a valid falloff test is the task of the operator. Operators should QA/QC the pressure data and test results to confirm that the results "make sense" prior to submission of the report to the EPA for review.

3.0 Timing of Falloff Tests and Report Submission

Falloff **tests** must be conducted annually. The time **interval** for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals.

The falloff testing **report** should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

4.0 Falloff Test Report Requirements

In general, the **report** to EPA should provide:

(1) general information and an overview of the falloff test,
(2) an analysis of the pressure data obtained during the test,
(3) a summary of the test results, and
(4) a comparison of those results with previously used parameters.

Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The **falloff test report** should include the following information:

1. **Company name and address**
2. **Test well name and location**
3. The name and phone number of **the facility contact person**. The contractor contact may be included if approved by the facility in addition to a facility contact person.
4. **A photocopy of an openhole log** (SP or Gamma Ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. **Well schematic** showing the current wellbore configuration and completion information:
    - Wellbore radius
    - Completed interval depths
    - Type of completion (perforated, screen and gravel packed, openhole)
6. **Depth of fill depth and date tagged.**
7. **Offset well information:**
    - Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
    - Simple illustration of locations of the injection and offset wells
8. **Chronological listing of daily testing activities.**
9. **Electronic submission of the raw data (time, pressure, and temperature)** from all pressure gauges utilized on CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any

edited data used in the analysis can be submitted as an additional file.

10. **Tabular summary of the injection rate or rates preceding the falloff test.** At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
11. **Rate information from any offset wells completed in the same interval.** At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.
12. **Hard copy of the time and pressure data** analyzed in the report.
13. **Pressure gauge information:** (See Appendix, page A-1 for more information on pressure gauges)
    - List all the gauges utilized to test the well
    - Depth of each gauge
    - Manufacturer and type of gauge. Include the full range of the gauge.
    - Resolution and accuracy of the gauge as a % of full range.
    - Calibration certificate and manufacturer's recommended frequency of calibration
14. **General test information:**
    - Date of the test
    - Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well and any offset wells.
    - Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
15. **Reservoir parameters (determination):**
    - Formation fluid viscosity, μ_f cp (direct measurement or correlation)
    - Porosity, φ fraction (well log correlation or core data)
    - Total compressibility, c_t psi^{-1} (correlations, core measurement, or well test)
    - Formation volume factor, rvb/stb (correlations, usually assumed 1 for water)
    - Initial formation reservoir pressure - See Appendix, page A-1
    - Date reservoir pressure was last stabilized (injection history)
    - Justified interval thickness, h ft - See Appendix, page A-15
16. **Waste plume:**
    - Cumulative injection volume into the completed interval
    - Calculated radial distance to the waste front, r_{waste} ft
    - Average historical waste fluid viscosity, if used in the analysis, μ_{waste} cp

17. **Injection period:**
    - Time of injection period
    - Type of test fluid
    - Type of pump used for the test (e.g., plant or pump truck)
    - Type of rate meter used
    - Final injection pressure and temperature
18. **Falloff period:**
    - Total shut-in time, expressed in real time and Δt, elapsed time
    - Final shut-in pressure and temperature
    - Time well went on vacuum, if applicable
19. **Pressure gradient:**
    - Gradient stops - for depth correction
20. **Calculated test data:** include all equations used and the parameter values assigned for each variable within the report
    - Radius of investigation, r_i ft
    - Slope or slopes from the semilog plot
    - Transmissibility, kh/μ md-ft/cp
    - Permeability (range based on values of h)
    - Calculation of skin, s
    - Calculation of skin pressure drop, ΔP_{skin}
    - Discussion and justification of any reservoir or outer boundary models used to simulate the test
    - Explanation for any pressure or temperature anomaly if observed
21. **<u>Graphs:</u>**
    - Cartesian plot: pressure and temperature vs. time
    - Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
    - Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
    - Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. **A copy of the latest radioactive tracer run** and a brief discussion of the results.

5.0 Planning

The **<u>radial flow portion</u>** of the test is the basis for all pressure transient calculations. Therefore the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

<u>General Operational Concerns</u>

- Adequate storage for the waste should be ensured for the duration of the test

- Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be **analyzed as an interference test** to obtain interwell reservoir parameters.

Site Specific Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
   - Review previous welltests, if available
   - Simulate the test using measured or estimated reservoir and well completion parameters
   - Calculate the time to the beginning of radial flow using the empirically-based equations provided in the Appendix. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period. (See Appendix, page A-4 for equations)
   - Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well developed semilog straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.

2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to

produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The viscosity of the fluid should be consistent. Any mobility issues (k/μ) should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are required. (See Appendix, page A-2 for additional information concerning pressure gauge selection.)

4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type. (See Appendix, page A-1 for additional information concerning pressure gauges.)

6.0 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well

2. Simplify the pressure transients in the reservoir
    - Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
    - Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
    - Do not shut-in two wells simultaneously or change the rate in an offset well during the test.

3. The test well should be shut-in at the wellhead in order to minimize wellbore storage and afterflow. (See Appendix, page A-3 for additional information.)

4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.

5. Measure and record the viscosity of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.

7.0 Evaluation of the Falloff Test

1. Prepare a **Cartesian plot** of the pressure and temperature versus real time or elapsed time.
    - Confirm pressure stabilization prior to shut-in of the test well
    - Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution

2. Prepare a **log-log diagnostic plot** of the pressure and semilog derivative. Identify the

flow regimes present in the welltest. (See Appendix, page A-6 for additional information.)

- Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff (See Appendix, page A-10 for details on time functions.)
- **Mark the various flow regimes** - particularly the radial flow period
- Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
- If there is no radial flow period, attempt to type curve match the data

3. Prepare a **semilog plot**.
   - Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
   - Draw the semilog straight line through the radial flow portion of the plot and
   - obtain the slope of the line
   - Calculate the transmissibility, kh/μ
   - Calculate the skin factor, s, and skin pressure drop, ΔP_{skin}
   - Calculate the radius of investigation, r_i

4. Explain any anomalous results.

8.0 Technical References

1. SPE Textbook Series No. 1, "Well Testing," 1982, W. John Lee
2. SPE Monograph 5, "Advances in Well Test Analysis," 1977, Robert Earlougher, Jr.
3. SPE Monograph 1, "Pressure Buildup and Flow Tests in Wells," 1967, C.S. Matthews and D.G. Russell
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7. "Pressure Transient Analysis," Stanislav and Kabir, 1990
8. "Well Testing: Interpretation Methods," Bourdarot, 1996
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14. "Guidelines Simplify Well Test Interpretation," Oil and Gas Journal, Ehlig-Economides, Hegeman, and Vik, July 18, 1994
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17. "Radius-of-Drainage and Stabilization-Time Equations," Oil and Gas Journal, H.K. Van Poollen, Sept 14, 1964
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19. "Three Key Elements Necessary for Successful Testing," Oil and Gas Journal, Ehlig-Economides, Hegeman, Clark, July 25, 1994
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22. "Fundamentals of Type Curve Analysis," Hart's Petroleum Engineer International, Spivey, and Lee, September 1997
23. "Identifying Flow Regimes In Pressure Transient Tests," Hart's Petroleum Engineer International, Spivey and Lee, October 1997
24. "Selecting a Reservoir Model For Well Test Interpretation," Hart's Petroleum Engineer International, Spivey, Ayers, Pursell,and Lee, December 1997
27. "Use of Pressure Derivative in Well-Test Interpretation," SPE Paper 12777, SPE Formation Evaluation Journal, Bourdet, Ayoub, and Pirard, June 1989
28. "A New Set of Type Curves Simplifies Well Test Analysis," World Oil, Bourdet, Whittle, Douglas, and Pirard, May 1983

APPENDIX

Pressure Gauge Usage and Selection

Usage

- EPA recommends that two gauges be used during the test with one gauge serving as a backup.
- **Downhole pressure measurements** are less noisy and are required.
- A bottomhole surface readout gauge (SRO) allows tracking of pressures in real time. Analysis of this data can be performed in the field to confirm that the well has reached radial flow prior to ending the test.
- The derivative function plotted on the log-log plot amplifies noise in the data, so the use of a good pressure recording device is critical for application of this curve.
- Mechanical gauges should be **calibrated** before and after each test using a dead weight tester.
- Electronic gauges should also be **calibrated** according to the manufacturer's recommendations. The manufacturer's recommended frequency of calibration, and a copy of the gauge calibration certificate should be provided with the falloff testing report demonstrating this practice has been followed.

Selection

- The pressures must remain within the range of the pressure gauge. The larger percent of the gauge range utilized in the test, the better. Typical pressure gauge limits are 2000, 5000, and 10000 psi. Note that gauge accuracy and resolution are typically a function of percent of the full gauge range.
- Electronic downhole gauges generally offer much better resolution and sensitivity than a mechanical gauge but cost more. Additionally, the electronic gauge can generally run for a longer period of time, be programmed to measure pressure more frequently at various intervals for improved data density, and store data in digital form.
- Resolution of the pressure gauge must be sufficient to measure small pressure changes at the end of the test.

Test Design

General Operational Considerations

- The injection period controls what is seen on the falloff since the falloff is replay of the injection period. Therefore, the injection period must reach radial flow prior to shut-in of the well in order for the falloff test to reach radial flow
- Ideally to determine the optimal lengths of the injection and falloff periods, the test should be simulated using measured or estimated reservoir parameters. Alternatively, injection and falloff period lengths can be estimated from empirical equations using assumed reservoir and well parameters.

- The injection rate dictates the pressure buildup at the injection well. The pressure buildup from injection must be sufficient so that the pressure change during radial flow, usually occurring toward the end of the test, is large enough to measure with the pressure gauge selected.

- Waste storage and other operational issues require preplanning and need to be addressed prior to the test date. If brine must be brought in for the injection portion of the test, operators should insure that the fluid injected has a consistent viscosity and that there is adequate fluid available to obtain a valid falloff test. The use of the wastestream as the injection fluid affords several distinct advantages:
  1. Brine does not have to be purchased or stored prior to use.
  2. Onsite waste storage tanks may be used.
  3. Plant wastestreams are generally consistent, i.e., no viscosity variations

- Rate changes cause pressure transients in the reservoir. **Constant rate injection in the test well and any offset wells completed in the same reservoir are critical to simplify the pressure transients in the reservoir.** Any significant injection rate fluctuations at the test well or offsets must be recorded and accounted for in the analysis using superposition.

- Unless an injectivity test is to be conducted, shutting in the well for an extend period of time prior to conducting the falloff test reduces the pressure buildup in the reservoir and is not recommended.

- Prior to conducting a test, a crown valve should be installed on the wellhead to allow the pressure gauge to be installed and lowered into the well without any interruption of the injection rate.

- The wellbore schematic should be reviewed for possible obstructions located in the well that may prevent the use or affect the setting depth of a downhole pressure gauge. The fill depth in the well should also be reported. The fill depth may not only impact the depth of the gauge, but usually prolongs the wellbore storage period and depending on the type of fill, may limit the interval thickness by isolating some of the injection intervals. A wellbore cleanout or stimulation may be needed prior to conducting the test for the test to reach radial flow and obtain valid results.

- The location of the shut-in valve can impact the duration of the wellbore storage period. The shut-in valve should be located near the wellhead. Afterflow into the wellbore prolongs the wellbore storage period.
- The area geology should be reviewed prior to conducting the test to determine the thickness and type of formation being tested along with any geological features such as natural fractures, a fault, or a pinchout that should be anticipated to impact the test.

Wellbore and Reservoir Data Needed to Simulate or Analyze the Falloff Test

- Wellbore radius, r_w - from wellbore schematic

- Net thickness, h - See Appendix, page A-15
- Porosity, φ - log or core data
- Viscosity of formation fluid, μ_f - direct measurement or correlations
- Viscosity of waste, μ_{waste} - direct measurement or correlations
- Total system compressibility, c_t - correlations, core measurement, or well test
- Permeability, k - previous welltests or core data
- Specific gravity of injection fluid, s.g. - direct measurement
- Injection rate, q - direct measurement

Design Calculations

When simulation software is unavailable the test periods can be estimated from empirical equations. The following are set of steps to calculate the time to reach radial flow from empirically-derived equations:

1. Estimate the wellbore storage coefficient, C (bbl/psi). There are two equations to calculate the wellbore storage coefficient depending on if the well remains fluid filled (positive surface pressure) or if the well goes on a vacuum (falling fluid level in the well):

    a. Well remains fluid filled:

    $C = V_w \cdot c_{waste}$ where, V_w is the total wellbore volume, bbls
    c_{waste} is the compressibility of the injectate, psi^{-1}

    b. Well goes on a vacuum:

    $$C = \frac{V_u}{\frac{\rho \cdot g}{144 \cdot g_c}}$$ where, V_u is the wellbore volume per unit length, bbls/ft
    ρ is the injectate density, psi/ft
    g and g_c are gravitational constants

2. Calculate the time to reach radial flow for both the injection and falloff periods. Two different empirically-derived equations are used to calculate the time to reach radial flow, $t_{radial\ flow}$, for the injectivity and falloff periods:

    a. Injectivity period:

    $$t_{radial\,flow} > \frac{(200000 + 12000s) \cdot C}{\frac{k \cdot h}{\mu}} \; hours$$

    b. Falloff period:

    $$t_{radial\,flow} > \frac{170000 \cdot C \cdot e^{0.14 s}}{\frac{k \cdot h}{\mu}} \; hours$$

    The wellbore storage coefficient is assumed to be the same for both the injectivity and falloff periods. The skin factor, s, influences the falloff more than the injection period. Use these equations with caution, as they tend to fall apart for a well with a large permeability or a high skin factor. Also remember, the welltest should not only reach radial flow, but also sustain radial flow for a timeframe sufficient for analysis of the radial flow period. As a rule of thumb, a timeframe sufficient for analysis is 3 to 5 times the time needed to reach radial flow.

3. As an alternative to steps 1 and 2, to look a specific distance "L" into the reservoir and possibly confirm the absence or existence of a boundary, the following equation can be used to estimate the time to reach that distance:

$$t_{boundary} = \frac{948 \cdot \phi \cdot \mu \cdot c_t \cdot L_{boundary}}{k} \quad hours$$

where, $L_{boundary}$ = feet to boundary
$t_{boundary}$ = time to boundary, hrs

Again, this is the time to reach a distance "L" in the reservoir. Additional test time is required to observe a fully developed boundary past the time needed to just reach the boundary. As a rule of thumb, to see a fully developed boundary on a log-log plot, allow at least 5 times the time to reach it. Additionally, for a boundary to show up on the falloff, it must first be encountered during the injection period.

4. Calculate the expected slope of the semilog plot during radial flow to see if gauge resolution will be adequate using the following equation:

$$m_{semlog} = \frac{162.6 \cdot q \cdot B}{\frac{k \cdot h}{\mu}}$$

where, q = the injection rate preceding the falloff test, bpd
B = formation volume factor for water, rvb/stb (usually assumed to be 1)

Considerations for Offset Wells Completed in the Same Interval

Rate fluctuations in offset wells create additional pressure transients in the reservoir and complicate the analysis. Always try to simplify the pressure transients in the reservoir. Do not simultaneously shut-in an offset well and the test well. The following items are key considerations in dealing with the impact of offset wells on a falloff test:

- Shut-in all offset wells prior to the test
- If shutting in offset wells is not feasible, maintain a constant injection rate prior to and during the test
- Obtain accurate injection records of offset injection prior to and during the test
- At least one of the real time points corresponding to an injection rate in an offset well should be synchronized to a specific time relating to the test well
- **Following the falloff test in the test well, send at least two pulses from the offset well to the test well by fluctuating the rate in the offset well.** The pressure pulses can confirm communication between the wells and can be simulated in the analysis if observed at the test well. The pulses can also be analyzed as an interference test using an Ei type curve.

- If time permits, conduct an interference test to allow evaluation of the reservoir without the wellbore effects observed during a falloff test.

Falloff Test Analysis

In performing a falloff test analysis, a series of plots and calculations should be prepared to QA/QC the test, identify flow regimes, and determine well completion and reservoir parameters. Individual plots, flow regime signatures, and calculations are discussed in the following sections.

Cartesian Plot

- The pressure data prior to shut-in of the well should be reviewed on a Cartesian plot to confirm pressure stabilization prior to the test. A well that has reached radial flow during the injectivity portion of the test should have a consistent injection pressure.

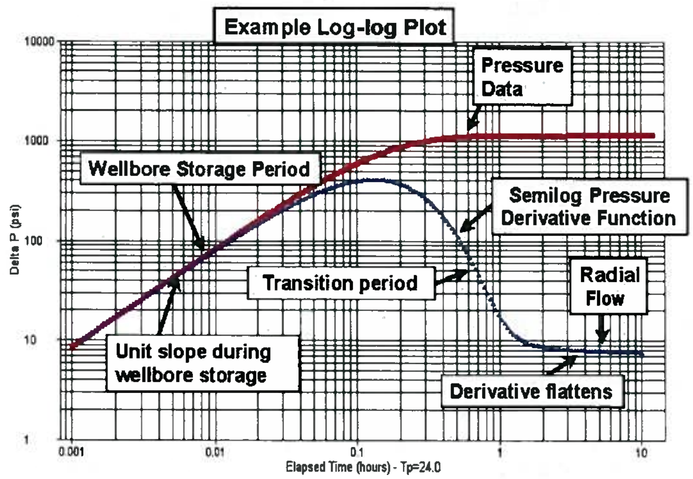
- A Cartesian plot of the pressure and temperature versus real time or elapsed time should be the first plot made from the falloff test data. Late time pressure data should be expanded to determine the pressure drop occurring during this portion of the test. The pressure changes should be compared to the pressure gauges used to confirm adequate gauge resolution existed throughout the test. If the gauge resolution limit was reached, this timeframe should be identified to determine if radial flow was reached prior to reaching the resolution of the pressure gauge. Pressure data obtained after reaching the resolution of the gauge should be treated as suspect and may need to be discounted in the analysis.

- **Falloff tests conducted in highly transmissive reservoirs** may be more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. Region 6 has observed cases in which large temperature anomalies were not properly compensated for by the pressure gauge, resulting in erroneous pressure data and an incorrect analysis. For this reason, the Cartesian plot of the temperature data should be reviewed. **Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.**

- Include the injection rate(s) of the test well 48 hours prior to shut-in on the Cartesian plot to illustrate the consistency of the injection rate prior to shut-in and to determine the appropriate time function to use on the log-log and semilog plots. (See Appendix, page A10 for time function selection)

Log-log Diagnostic Plot

- Plot the pressure and semilog derivative versus time on a log-log diagnostic plot. Use the appropriate time function based on the rate history of the injection period preceding the falloff. (See Appendix, page A-10 for time function selection) The log-log plot is used to identify the flow regimes present in the welltest. An example log-log plot is shown below:



Identification of Test Flow Regimes

- Flow regimes are mathematical relationships between pressure, rate, and time. Flow regimes provide a visualization of what goes on in the reservoir. Individual flow regimes have characteristic slopes and a sequencing order on the log-log plot.

- Various flow regimes will be present during the falloff test, however, not all flow regimes are observed on every falloff test. The late time responses correlate to distances further from the test well. **The critical flow regime is radial flow from which all analysis calculations are performed.** During radial flow, the pressure responses recorded are representative of the reservoir, not the wellbore.

- The derivative function amplifies reservoir signatures by calculating a running slope of a designated plot. The derivative plot allows a more accurate determination of the radial flow portion of the test, in comparison with the old method of simply proceeding 1½ log cycles from the end of the unit slope line of the pressure curve.

- The derivative is usually based on the semilog plot, but it can also be calculated based on other plots such as a Cartesian plot, a square root of time plot, a quarter root of time plot, and the 1/square root of time plot. Each of these plots are used to identify specific flow regimes. If the flow regime characterized by a specialized plot is present then when the derivative calculated from that plot is displayed on the log-log plot, it will appear as a "flat spot" during the portion of the falloff corresponding to the flow regime.

- **Typical flow regimes observed on the log-log plot** and their semilog derivative patterns are listed below:

Flow Regime	Semilog Derivative Pattern
Wellbore Storage	Unit slope
Radial Flow	Flat plateau
Linear Flow	Half slope
Bilinear Flow	Quarter slope
Partial Penetration	Negative half slope
Layering	Derivative trough
Dual Porosity	Derivative trough
Boundaries	Upswing followed by plateau
Constant Pressure	Sharp derivative plunge

Characteristics of Individual Test Flow Regimes

- **Wellbore Storage:**
  1. Occurs during the early portion of the test and is caused by the well being shut-in at the surface instead of the sandface
  2. Measured pressure responses are governed by well conditions and are not representative of reservoir behavior and are characterized by both the pressure and semilog derivative curves overlying a unit slope on the log-log plot
  3. Wellbore skin or a low permeability reservoir results in a slower transfer of fluid from the well to the formation, extending the duration of the wellbore storage period
  4. A wellbore storage dominated test is unanalyzable

- **Radial Flow:**
  1. The pressure responses are from the reservoir, not the wellbore
  2. The critical flow regime from which key reservoir parameters and completion conditions calculations are performed
  3. Characterized by a flattening of the semilog plot derivative curve on the log-log plot and a straight line on the semilog plot

- **Spherical Flow:**
  1. Identifies partial penetration of the injection interval at the wellbore
  2. Characterized by the semilog derivative trending along a negative half slope on the log-log plot and a straight line on the 1/square root of time plot
  3. The log-log plot derivative of the pressure vs 1/square root of time plot is flat

- **Linear Flow:**
  1. May result from flow in a channel, parallel faults, or a highly conductive fracture
  2. Characterized by a half slope on both the log-log plot pressure and semilog derivative curves with the derivative curve approximately 1/3 of a log cycle lower than the pressure curve and a straight line on the square root of time plot. 3. The log-log plot derivative of the pressure vs square root of time plot is flat

- **Hydraulically Fractured Well:**
  1. Multiple flow regimes present including wellbore storage, fracture linear flow, bilinear flow, pseudo-linear flow, formation linear flow, and pseudo-radial flow
  2. Fracture linear flow is usually hidden by wellbore storage
  3. Bilinear flow results from simultaneous linear flows in the fracture and from the formation into the fracture, occurs in low conductivity fractures, and is characterized by a quarter slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus quarter root of time plot
  4. Formation linear flow is identified by a half slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus square root of time plot
  5. Psuedo-radial flow is analogous to radial flow in an unfractured well and is characterized by flattening of semilog derivative curve on the log-log plot and a straight line on a semilog pressure plot

- **Naturally Fractured Rock:**
  1. The fracture system will be observed first on the falloff test followed by the total system consisting of the fractures and matrix.
  2. The falloff analysis is complex. The characteristics of the semilog derivative trough on the log-log plot indicate the level of communication between the fractures and the matrix rock.

- **Layered Reservoir:**
  1. Analysis of a layered system is complex because of the different flow regimes, skin factors or boundaries that may be present in each layer.
  2. The falloff test objective is to get a total tranmissibility from the **whole reservoir system.**
  3. Typically described as commingled (2 intervals with vertical separation) or crossflow (2 intervals with hydraulic vertical communication)

Semilog Plot

- The semilog plot is a plot of the pressure versus the log of time. There are typically four different semilog plots used in pressure transient and falloff testing analysis. After plotting the appropriate semilog plot, a straight line should be drawn through the points located within the equivalent radial flow portion of the plot identified from the log-log plot.

- Each plot uses a different time function depending on the length and variation of the injection rate preceding the falloff. These plots can give different results for the same test, so it is important that the appropriate plot with the correct time function is used for the analysis. Determination of the appropriate time function is discussed below.

- The slope of the semilog straight line is then used to calculate the reservoir transmissibility - kh/μ, the completion condition of the well via the skin factor - s, and also the radius of investigation - r_i of the test.

Determination of the Appropriate Time Function for the Semilog Plot

The following four different semilog plots are used in pressure transient analysis:

1. Miller Dyes Hutchinson (MDH) Plot
2. Horner Plot
3. Agarwal Equivalent Time Plot
4. Superposition Time Plot

These plots can give different results for the same test. Use of the appropriate plot with the correct time function is critical for the analysis.

- The **MDH plot** is a semilog plot of pressure versus Δt, where Δt is the elapsed shut-in time of the falloff.
  1. The MDH plot only applies to wells that reach psuedo-steady state during injection. Psuedo-steady state means the pressure response from the well has encountered all the boundaries around the well.
  2. The MDH plot is only applicable to injection wells with a *very* long injection period at a constant rate. This plot is not recommended for use by EPA Region 6.

- The **Horner plot** is a semilog plot of pressure versus $(t_p+\Delta t)/\Delta t$. The Horner plot is only used for a falloff preceded by a single constant rate injection period.
  1. The injection time, $t_p=V_p/q$ in hours, where V_p=injection volume since the last pressure equalization and q is the injection rate prior to shut-in for the falloff test. The injection volume is often taken as the cumulative injection since completion.
  2. The Horner plot can result in significant analysis error if the injection rate varies prior to the falloff.

- The **Agarwal equivalent time plot** is a semilog plot of the pressure versus Agarwal equivalent time, Δt_e.
  1. The Agarwal equivalent time function is similar to the Horner plot, but scales the falloff to make it look like an injectivity test.
  2. It is used when the injection period is a short, constant rate compared to the length of the falloff period.
  3. The Agarwal equivalent time is defined as: $\Delta t_e = \log(t_p\ \Delta t)/(t_p+\Delta t)$, where t_p is calculated the same as with the Horner plot.

- The **superposition time function** accounts for variable rate conditions preceding the falloff.
    1. It is the most rigorous of all the time functions and is usually calculated using welltest software.
    2. The use of the superposition time function requires the operator to accurately track the rate history. As a rule of thumb, at a minimum, the rate history for twice the length of the falloff test should be included in the analysis.

The determination of which time function is appropriate for the plotting the welltest on semilog and log-log plots depends on available rate information, injection period length, and software:

1. If there is not a rate history other than a single rate and cumulative injection, use a Horner time function
2. If the injection period is shorter than the falloff test and only a single rate is available, use the Agarwal equivalent time function
3. If you have a variable rate history use superposition when possible. As an alternative to superposition, use Agarwal equivalent time on the log-log plot to identify radial flow. The semilog plot can be plotted in either Horner or Agarwal time if radial flow is observed on the log-log plot.

Parameter Calculations and Considerations

- Transmissibility - The slope of the semilog straight line, m, is used to determine the transmissibility (kh/μ) parameter group from the following equation:

$$\frac{k \cdot h}{\mu} = \frac{162.6 \cdot q \cdot \mathrm{B}}{m}$$

where, q = injection rate, bpd (negative for injection)
B = formation volume factor, rvb/stb (Assumed to be 1 for formation fluid)
m = slope of the semilog straight line through the radial flow portion of the plot in psi/log cycle
k = permeability, md
h = thickness, ft (See Appendix, page A-15)
μ = viscosity, cp

- The viscosity, μ, is usually that of the formation fluid. However, if the waste plume size is massive, the radial flow portion of the test may remain within the waste plume. (See Appendix, page A-14)
    1. The waste and formation fluid viscosity values usually are similar, however, if the wastestream has a significant viscosity difference, the size of the waste plume and distance to the radial flow period should be calculated.
    2. The mobility, k/μ, differences between the fluids may be observed on the derivative curve.

- The permeability, k, can be obtained from the calculated transmissibility (kh/μ) by substituting the appropriate thickness, h, and viscosity, μ, values.

Skin Factor

- In theory, wellbore skin is treated as an infinitesimally thin sheath surrounding the wellbore, through which a pressure drop occurs due to either damage or stimulation. Industrial injection wells deal with a variety of waste streams that alter the near wellbore environment due to precipitation, fines migration, ion exchange, bacteriological processes, and other mechanisms. It is reasonable to expect that this alteration often exists as a zone surrounding the wellbore and not a skin. Therefore, at least in the case of industrial injection wells, the assumption that skin exists as a thin sheath is not always valid. This does not pose a serious problem to the correct interpretation of falloff testing except in the case of a large zone of alteration, or in the calculation of the flowing bottomhole pressure. Region 6 has seen instances in which large zones of alteration were suspected of being present.

- The skin factor is the measurement of the completion condition of the well. The skin factor is quantified by a positive value indicating a damaged completion and a negative value indicating a stimulated completion.
  1. The magnitude of the positive value indicating a damaged completion is dictated by the transmissibility of the formation.
  2. A negative value of -4 to -6 generally indicates a hydraulically fractured completion, whereas a negative value of -1 to -3 is typical of an acid stimulation in a sandstone reservoir.
  3. The skin factor can be used to calculate the effective wellbore radius, r_{wa} also referred to the apparent wellbore radius. (See Appendix, page A-13)
  4. The skin factor can also be used to correct the injection pressure for the effects of wellbore damage to get the actual reservoir pressure from the measured pressure.

- The skin factor is calculated from the following equation:

$$s = 1.1513\left[\frac{P_{1hr} - P_{wf}}{m} - \log\left(\frac{k \cdot t_p}{(t_p + 1)\cdot \phi \cdot \mu \cdot c_t \cdot r_w^2}\right) + 3.23\right]$$

where, s = skin factor, dimensionless

P_{1hr} = pressure intercept along the semilog straight line at a shut-in time of 1 hour, psi

P_{wf} = measured injection pressure prior to shut-in, psi

μ = appropriate viscosity at reservoir conditions, cp (See Appendix, page A-14)

m = slope of the semilog straight line, psi/cycle

k = permeability, md

φ = porosity, fraction

c_t = total compressibility, psi^{-1}

r_w = wellbore radius, feet

t_p = injection time, hours

Note that the term $t_p/(t_p + \Delta t)$, where Δt=1 hr, appears in the log term. This term is usually assumed to result in a negligible contribution and typically is taken as 1 for large t. However, for relatively short injection periods, as in the case of a drill stem test (DST), this term can be significant.

Radius of Investigation

- The radius of investigation, r_i, is the distance the pressure transient has moved into a formation following a rate change in a well.

- There are several equations that exist to calculate the radius of investigation. All the equations are square root equations based on cylindrical geometry, but each has its own coefficient that results in slightly different results, (See Oil and Gas Journal, Van Poollen, 1964).

- Use of the appropriate time is necessary to obtain a useful value of r_i. For a falloff time shorter than the injection period, use Agarwal equivalent time function, Δt_e, at the end of the falloff as the length of the injection period preceding the shut-in to calculate r_i.

- The following two equivalent equations for calculating r_i were taken from SPE Monograph 1, (Equation 11.2) and Well Testing by Lee (Equation 1.47), respectively:

$$r_i = \sqrt{0.00105\frac{k \cdot t}{\phi \cdot \mu \cdot c_t}} \equiv \sqrt{\frac{k \cdot t}{948 \cdot \phi \cdot \mu \cdot c_t}}$$

Effective Wellbore Radius

- The effective wellbore radius relates the wellbore radius and skin factor to show the effects of skin on wellbore size and consequently, injectivity.

- The effective wellbore radius is calculated from the following:

$$r_{wa} = r_w e^{-s}$$

- A negative skin will result in a larger effective wellbore radius and therefore a lower injection pressure.

Reservoir Injection Pressure Corrected for Skin Effects

- The pressure correction for wellbore skin effects, ΔP_{skin}, is calculated by the following:

$$\Delta P_{skin} = 0.868 \cdot m \cdot s$$

where, m = slope of the semilog straight line, psi/cycle
s = wellbore skin, dimensionless

- The adjusted injection pressure, P_{wfa} is calculated by subtracting the ΔP_{skin} from the measured injection pressure prior to shut-in, P_{wf}. This adjusted pressure is the calculated reservoir pressure prior to shutting in the well, $\Delta t=0$, and is determined by the following:

$$P_{wfa} = P_{wf} - \Delta P_{skin}$$

- From the previous equations, it can be seen that the adjusted bottomhole pressure is directly dependent on a single point, the last injection pressure recorded prior to shut-in. Therefore, an accurate recording of this pressure prior to shut-in is important. Anything that impacts the pressure response, e.g., rate change, near the shut-in of the well should be avoided.

Determination of the Appropriate Fluid Viscosity

- If the wastestream and formation fluid have similar viscosities, this process is not necessary.

- This is only needed in cases where the mobility ratios are extreme between the wastestream, $(k/\mu)_w$, and formation fluid, $(k/\mu)_f$. Depending on when the test reaches radial flow, these cases with extreme mobility differences could cause the derivative curve to change and level to another value. Eliminating alternative geologic causes, such as a sealing fault, multiple layers, dual porosity, etc., leads to the interpretation that this change may represent the boundary of the two fluid banks.

- First assume that the pressure transients were propagating through the formation fluid during the radial flow portion of the test, and then verify if this assumption is correct. This is generally a good strategy except for a few facilities with exceptionally long injection histories, and consequently, large waste plumes. The time for the pressure transient to exit the waste front is calculated. This time is then identified on both the log-log and semilog plots. The radial flow period is then compared to this time.

- The radial distance to the waste front can then be estimated volumetrically using the following equation:

$$r_{waste\,plume} = \sqrt{\frac{0.13368 \cdot V_{waste\,injected}}{\pi \cdot h \cdot \phi}}$$

where, $V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
$r_{waste\ plume}$ = estimated distance to waste front, ft
h = interval thickness, ft
φ = porosity, fraction

- The time necessary for a pressure transient to exit the waste front can be calculated using the following equation:

$$t_w = \frac{126.73 \cdot \mu_w \cdot c_t \cdot V_{waste\,injected}}{\pi \cdot k \cdot h}$$

where,
t_w = time to exit waste front, hrs
$V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
h = interval thickness, ft
k = permeability, md
μ_w = viscosity of the historic waste plume at reservoir conditions, cp
c_t = total system compressibility, psi^{-1}

- The **time should be plotted on both the log-log and semilog plots** to see if this time corresponds to any changes in the derivative curve or semilog pressure plot. If the time estimated to exit the waste front occurs before the start of radial flow, the assumption that the pressure transients were propagating through the reservoir fluid during the radial flow period was correct. Therefore, the viscosity of the reservoir fluid is the appropriate viscosity to use in analyzing the well test. If not, the viscosity of the historic waste plume should be used in the calculations. If the mobility ratio is extreme between the wastestream and formation fluid, adequate information should be included in the report to verify the appropriate fluid viscosity was utilized in the analysis.

Reservoir Thickness

- The thickness used for determination of the permeability should be justified by the operator. The net thickness of the defined injection interval is not always appropriate.

- The permeability value is necessary for plume modeling, but the transmissibility value, kh/μ, can be used to calculate the pressure buildup in the reservoir without specifying values for each parameter value of k, h, and μ.

- Selecting an interval thickness is dependent on several factors such as whether or not the injection interval is composed of hydraulically isolated units or a single massive unit and wellbore conditions such as the depth to wellbore fill. When hydraulically isolated sands are present, it may be helpful to define the amount of injection entering each interval by conducting a flow profile survey. Temperature logs can also be reviewed to evaluate the intervals receiving fluid. Cross-sections may provide a quick look at the continuity of the injection interval around the injection well.

- A copy of a SP/Gamma Ray well log over the injection interval, the depth to any fill, and the log and interpretation of available flow profile surveys run should be submitted with the falloff test to verify the reservoir thickness value assumed for the permeability calculation.

Use of Computer Software

- To analyze falloff tests, operators are encouraged to use well testing software. Most software has type curve matching capabilities. This feature allows the simulation of the entire falloff test results to the acquired pressure data. This type of analysis is particularly useful in the recognition of boundaries, or unusual reservoir characteristics, such as dual porosity. It should be noted that type curve matching is not considered a substitute, but is a compliment to the analysis.

- All data should be submitted on a CD-ROM with a label stating the name of the facility, the well number(s), and the date of the test(s). The label or READ.Me file should include the names of all the files contained on the CD, along with any necessary explanations of the information. The parameter units format (hh:mm:ss, hours, etc.) should be noted for the pressure file for synchronization to the submitted injection rate information. The file containing the gauge data analyzed in the report should be identified and consistent with the hard copy data included in the report. If the injection rate information for any well included in the analysis is greater than 10 entries, it should also be included electronically.

Common Sense Check

- After analyzing any test, always look at the results to see if they "make sense" based on the type of formation tested, known geology, previous test results, etc. Operators are ultimately responsible for conducting an analyzable test and the data submitted to the regulatory agency.

- If boundary conditions are observed on the test, review cross-sections or structure maps to confirm if the presence of a boundary is feasible. If so, the boundary should be considered in the AOR pressure buildup evaluation for the well.

- Anomalous data responses may be observed on the falloff test analysis. These data anomalies should be evaluated and explained. The analyst should investigate physical causes in addition to potential reservoir responses. These may include those relating to the well equipment, such as a leaking valve, or a channel, and those relating to the data acquisition hardware such as a faulty gauge. An anomalous response can often be traced to a brief, but significant rate change in either the test well or an offset well.

- Anomalous data trends have also been caused by such things as ambient temperature changes in surface gauges or a faulty pressure gauge. Explanations for data trends may be facilitated through an examination of the backup pressure gauge data, or the temperature data. It is often helpful to qualitatively examine the pressure and/or temperature channels from both gauges. The pressure data should overlay during the falloff after being corrected for the difference in gauge depths. On occasion, abrupt temperature changes can be seen to correspond to trends in the pressure data. Although the source of the temperature changes may remain unexplainable, the apparent correlation of the temperature anomaly to the pressure anomaly can be sufficient reason to question the validity of the test and eliminate it from further analysis.

- The data that is obtained from pressure transient testing should be compared to permit parameters. Test derived transmissibilities and static pressures can confirm compliance with non-endangerment (Area Of Review) conditions.

APPENDIX F – Region 9 Step Rate Test Policy

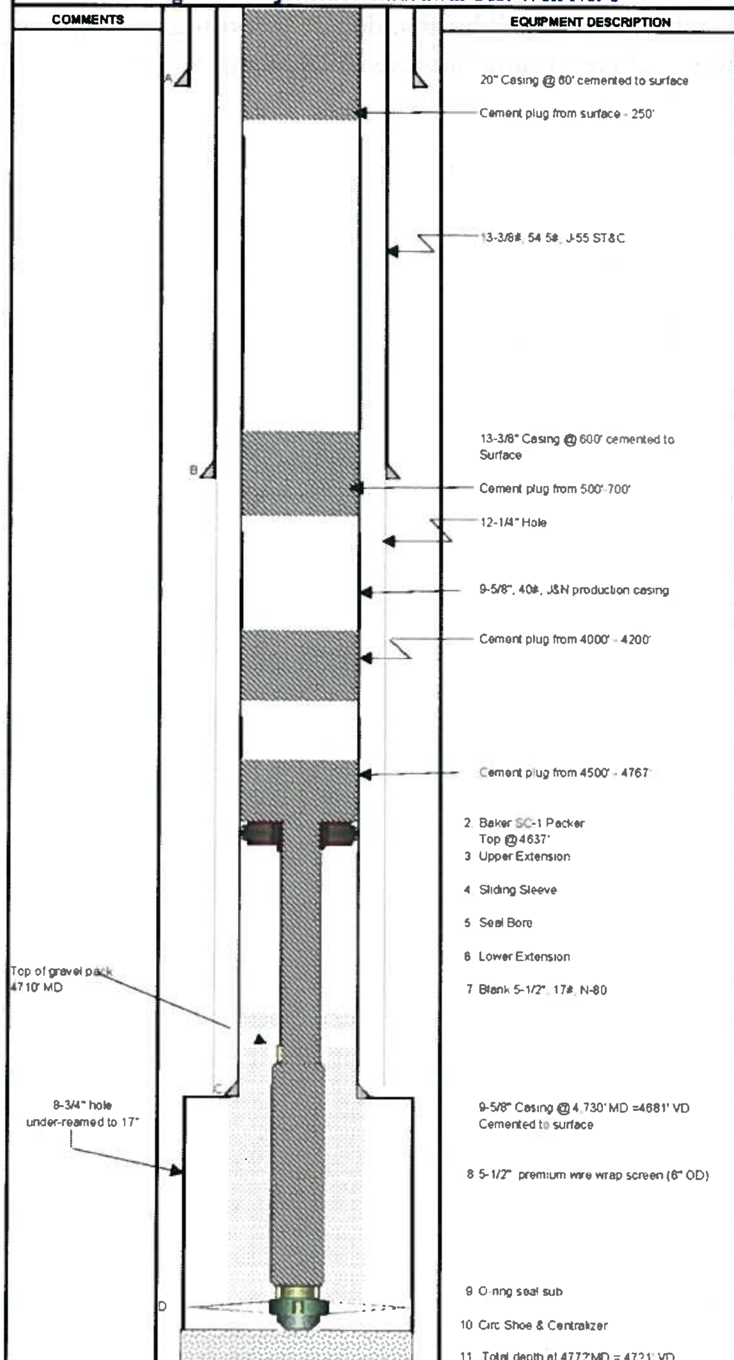
For reference please refer to:
Society of Petroleum Engineers (SPE) Paper #16798,
Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure
(This paper may be obtained from the SPE)

APPENDIX G - Plugging and Abandonment Plans

Upon completion of injection activities the well(s) shall be abandoned according to State and Federal regulations to ensure protection of Underground Sources of Drinking Water.

Proposed Abandonment Schematic

King Island Injection-Withdrawal Test Well No. 1



PBTD	4772'	MD	4721'	TVD
TD	4772'	MD	4721'	TVD

Completed

File

J:\Project Active\WorleyParsons PGE CAES\Task 3 7 4_3 7 7 & 3 7 8 UIC Permit\Permit Application\Final Permit Application Changes\Attachment Q\P&A Programs\Attachment Q3\[King Island Test Well No 1 WBD abandonment xls]Actual WBD

PG&E
WELL COMPLETION DIAGRAM

FIELD	NA		
WELL #	King Island I-W Test Well No 1		
Ground MSL -6'			
KB	6'		
LOCATION	Sec 27, T 3N, R 5E, MDB&M		

DIRECTIONAL DATA

MAX ANGLE	20	THRU ZONE	4772'
KOP	3465'	HOLE TYPE	Directional
BH Location	Vertical	255' N & 215' E	

SURFACE EQUIPMENT

TREE	3" 3M
SWAB CAP SIZE & THRD	8rd EUE lift thread
TOP TREE FLANGE	5" 3M
TUBING SPOOL FLANGE	11" 3M

TUBING DETAIL

	1st or LS	SS or Btm of Taper
SIZE	5-1/2"	
WEIGHT	15 5#	
GRADE	J-55	
DEPTH	4637'	
THREAD	LT&C	
NEW/USED	NEW	
COATING	None	
SCSSV	None	
Min I D	4 825"	

	O D (in)	I D (in)	LENGTH (ft)	DESCRIPTION
1	5-1/2"	4 825"	4637'	5-1/2", 15 5#, J-55
2	8"	5"	5'	Baker SC-1 Packer
3	5 5"	4 892	6'	Upper Extension
4	5 81"	4 892	2'	Baker Model S Sliding Sleeve
5	5 56"	4 892	1'	Baker Seal Bore
6	5 56"	4 892'	17'	Lower Extension
7	5 5"	4 892	38 00	Blank 5-1/2", 17#, N-80
8	6"	4 892	62'	51/2" Wire wraped screen
9	5 5"	1 813"	2 71	O-ring seal sub
10	5 5"	N/A	1 80	shoe
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				

CASING DETAIL

#	SIZE	WGHT	GRADE	THRD	DEPTH
A	20"	53#	NA		0' - 60'
B	13-3/8"	54 5	J-55	LT&C	0' - 600'
C	9-5/8""	40#	J&N	LT&C	0' - 4,702'
D	5-1/2"	17#	N-80	LT&C	4637'-4772'
E					
F					
G					
H					
I					
J					
K					
L					
M					
N					

Prepared By	Saeed Irani	Date	January 2, 2014
Updated By	Saeed Irani	Date	January 2, 2014
		Printed on	April 16, 2014

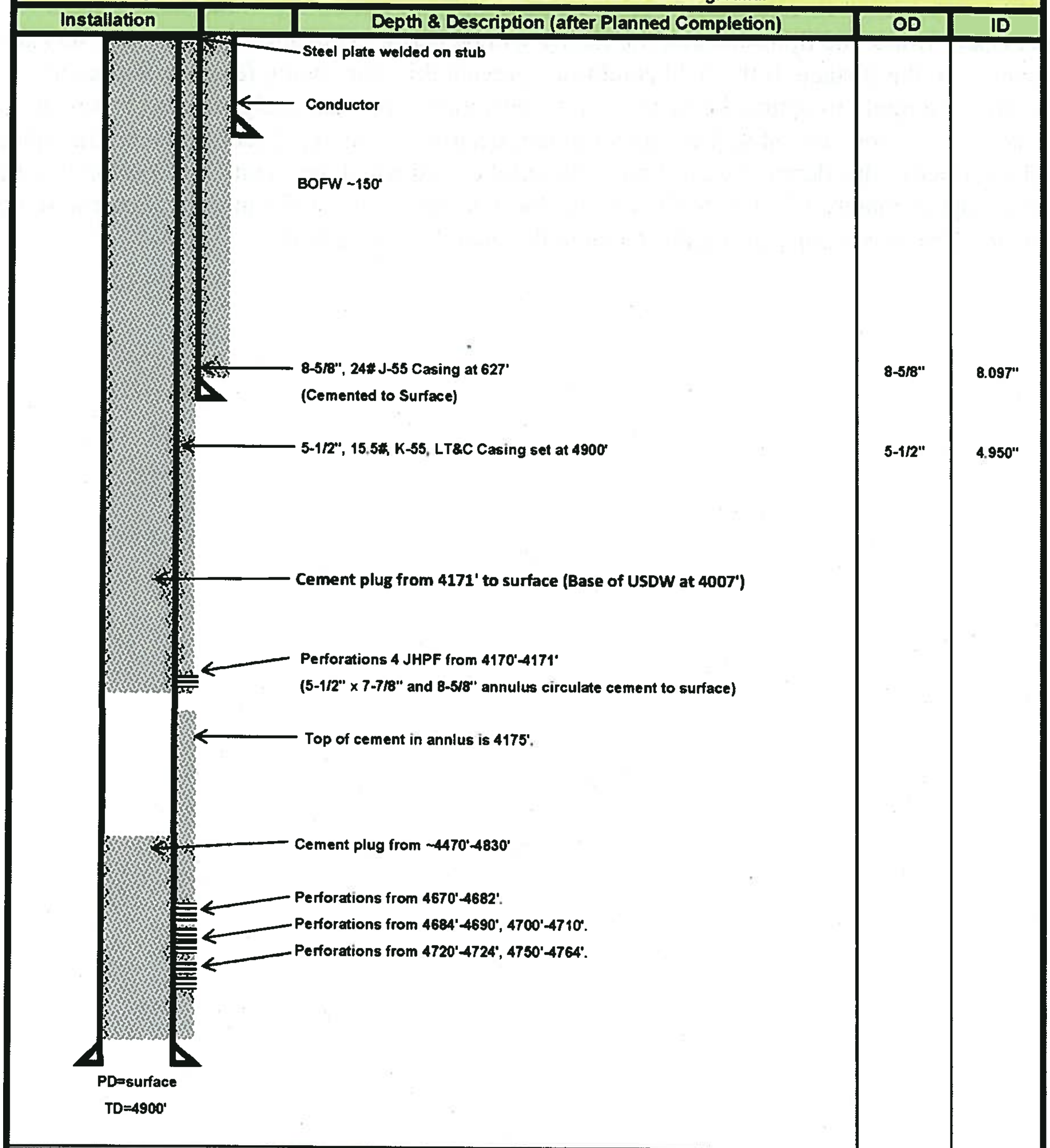
Piacentine 1-27

Three scenarios are provided to address the potential situations which may arise as a result of the Permittee striving to meet the EPA requirement for the placement of at least 200 feet of cement across the base of USDWs, and if possible, to circulate cement in the annulus to the surface.

Circulating cement to the surface from 100 feet below the USDW may prove difficult. As a contingency option, three different scenarios for cementing the casing to the surface were developed. Under the first scenario, the casing will be perforated from 4,170 to 4,171 feet and cemented to the surface. If the field conditions prevent this from being feasible, the second scenario will apply in which the casing will be perforated approximately 100 feet below the surface casing, and cement will be squeezed to the surface. Finally, if cement cannot be squeezed to the surface at this depth, the third scenario will be used which will consist of perforating the casing approximately 100-150 feet below the base of freshwater, and squeezing cement to the surface. The three scenarios are presented in the next three diagrams.

Piacentine 1-27 (API No. 077-20484) Abandonment WBD Scenario No. 1
San Joaquin, California
Sec 27, T 3N, R 5E

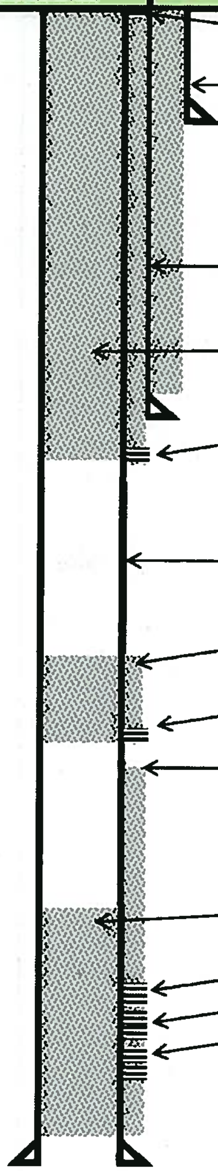
Location: Section 27, T 3N, R 5E, San Joaquin, California.
Elevation: -6.5' ground, +6.5' KB. All the measurements are from KB which is 13' above ground.



Prepared by Irani Engineering 4/5/2014

Piacentine 1-27 (API No. 077-20484) Abandonment WBD Scenario 2
San Joaquin, California
Sec 27, T 3N, R 5E

Location: Section 27, T 3N, R 5E, San Joaquin, California.
Elevation: -6.5' ground, +6.5' KB. All the measurements are from KB which is 13' above ground.

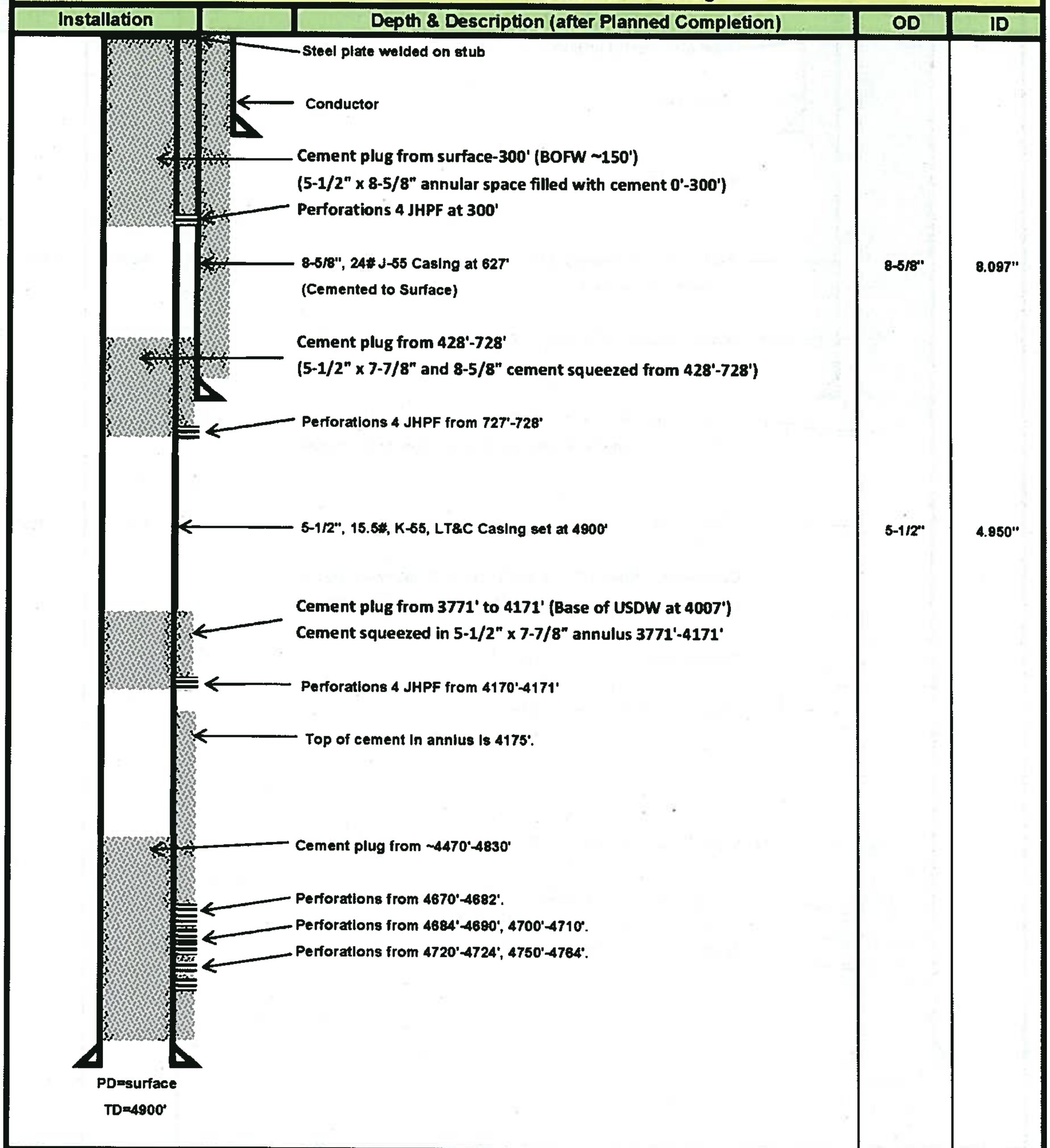


Installation		Depth & Description (after Planned Completion)	OD	ID
		Steel plate welded on stub		
		Conductor		
		BOFW ~150'		
		8-5/8", 24# J-55 Casing at 627' (Cemented to Surface)	8-5/8"	8.097"
		Cement plug from surface to 728'		
		Perforations 4 JHPF from 727'-728' (5-1/2" x 7-7/8" and 8-5/8" annulus circulate cement to surface)		
		5-1/2", 15.5#, K-55, LT&C Casing set at 4900'	5-1/2"	4.950"
		Cement plug from 3771' to 4171' (Base of USDW at 4007') Cement squeezed in 5-1/2" x 7-7/8" annulus 3771'-4171'		
		Perforations 4 JHPF from 4170'-4171'		
		Top of cement in annlus is 4175'.		
		Cement plug from ~4470'-4830'		
		Perforations from 4670'-4682'.		
		Perforations from 4684'-4690', 4700'-4710'.		
		Perforations from 4720'-4724', 4750'-4764'.		

Prepared by Irani Engineering 4/5/2014

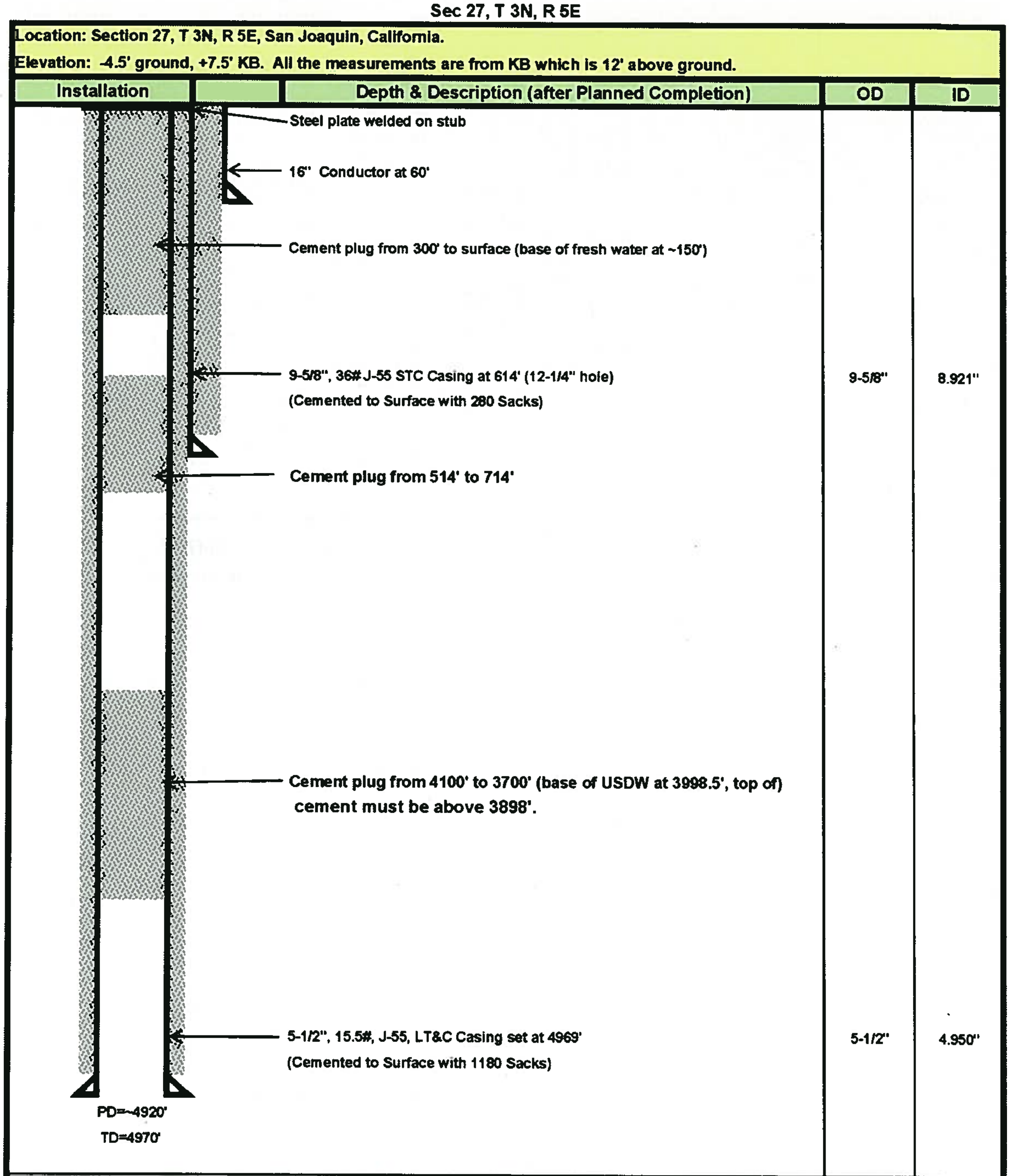
Piacentine 1-27 (API No. 077-20484) Abandonment WBD Scenario 3
San Joaquin, California
Sec 27, T 3N, R 5E

Location: Section 27, T 3N, R 5E, San Joaquin, California.
Elevation: -6.5' ground, +6.5' KB. All the measurements are from KB which is 13' above ground.



Prepared by Irani Engineering 4/5/2014

Piacentine 2-27 (API No. 077-20736) Abandonment WBD
San Joaquin, California
Sec 27, T 3N, R 5E



Prepared by Irani Engineering 1/2/2014

APPENDIX H – Operations, Testing and Monitoring Plans

ATTACHMENT H

Operating Data

CONTENTS

H.1 REQUIREMENTS

The operating data to be submitted for all injection wells to be covered under the requested permit includes the following:

- Average and maximum daily rate and volume of the fluids to be injected;
- Average and maximum injection pressure;
- Nature of annular fluid; and
- Source and analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness, of injection fluids.

Because the requested permit will include the proposed monitoring wells also, the above information will also be provided for these wells, to the extent applicable.

H.2 INJECTION RATE, VOLUME AND PRESSURES OF FLUIDS TO BE INJECTED

The proposed compression testing program will involve the injection of oxygen-depleted air[1] over a period of approximately 65 days to build an "air bubble" approximately 500 million standard cubic feet (MMscf) in size and conduct a series of injection, flow and shut in tests while observing the reservoir response. Based on the results of testing with oxygen-depleted air, a short test involving the injection of ambient air may be conducted if certain decision criteria are met, including stringent safety criteria. The total duration of the compression test will not exceed approximately 90 days. The size of the proposed air bubble is between 3 and 4 percent of the estimated original gas in place in the King Island gas reservoir (13.8 BSCF).

The compression testing program is divided into five phases as presented below in Table H-1.

TABLE H-1: SUMMARY OF COMPRESSION TESTING PROGRAM PHASING AND ACTIVITIES

Test Phase		Test Activity	Approximate Duration[1]
1	Bubble Building	Oxygen-depleted air injection	44 days
		Injection fall-off test (FOT)	2 days
2	Bubble Equilibration Period	Shut-in / FOT	2 days
		Multi-rate injection test	1.5 days
		Shut-in / FOT	3 days

[1] A membrane separation system will be incorporated into the air compression train at the surface and used to remove oxygen from the injection stream. The oxygen content of the air will be depleted to approximately to less than 5 percent by volume. The surface equipment used to deliver compressed air to the injection well is further described in Attachment K.

Test Phase		Test Activity	Approximate Duration [1]
3	Withdrawal/Injection Cycle Testing	Well clean-up	4 hours
		Shut-in / Equilibration	2 days
		Isochronal test (flow after flow)	8 hours
		Shut-in / FOT	2 days
		Series 1 oxygen-depleted air injection/ withdrawal/shut-in cycling	3 ½ days
		Shut-in / Equilibration	4 days
		Series 2 oxygen-depleted air injection/ withdrawal/shut-in cycling	3 ½ days
4	Preliminary Data Evaluation and Post-Test Equilibration	Shut in, evaluate data, decision regarding further testing with ambient air (optional)[2]	7 days
5	Additional Testing with Ambient Air	Additional testing using ambient air, if conducted[2]	11 days

Notes:
1. Actual durations of the test phases may change somewhat based on the equipment mobilized and equipment performance under field conditions.
2. The reservoir will be blown down during Phase 4 and after Phase 5 to decrease pressures and the volume of the air bubble to the extent it is feasible to do so.

Reservoir and well performance tests will be performed during the compression test. The purpose of the tests is to evaluate both Injection/Withdrawal Well and reservoir performance properties. The timing of the tests during the compression testing program schedule is shown on Figure H-1. The well performance tests are described in Table H-3.

TABLE H-2: OVERVIEW OF PLANNED WELL AND RESERVOIR PERFORMANCE TESTS

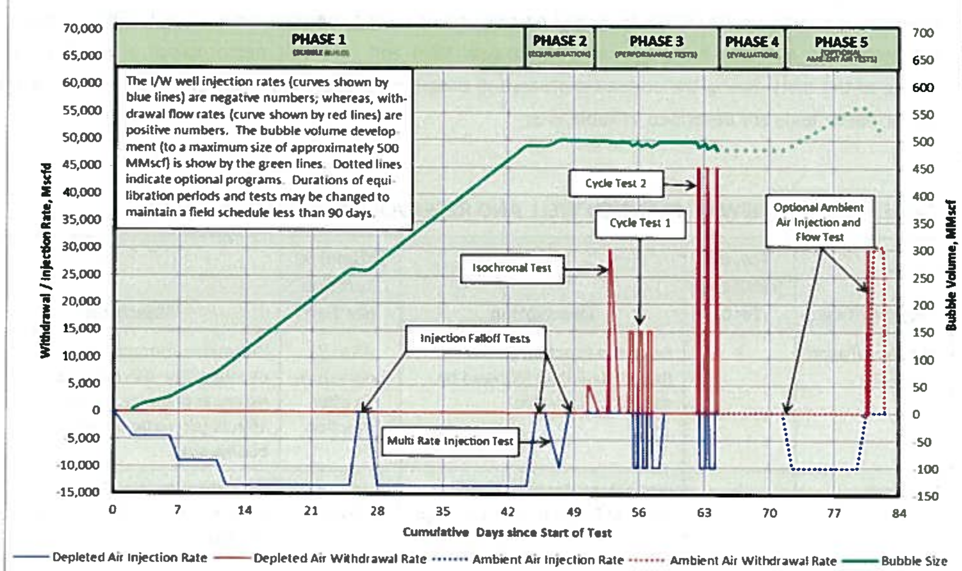
Type of Test	No. of Individual Tests	Description	Estimated Duration per Test	Objectives
Injectivity/Falloff Test (FOT)	3	Extended injection period (bubble building) followed by short shut-in period	48 to 72 hours shut-in after injection	Determine formation permeability, skin damage, reservoir pressure, boundary effects (air-water contact) and bubble size.
Multi-rate Injection Flow Test	1	Increasing rates of 4, 7 and 10 MMscfd for 10 to 12 hours each	Up to 36 hours	Determine air injection flow potential and wellbore effects (friction)

Type of Test	No. of Individual Tests	Description	Estimated Duration per Test	Objectives
Isochronal Test	1	Flow after flow with increasing rates (4 rates x 1 hour each) up to 45 MMscfd	<1 day	Determine air flow potential, absolute open flow, skin damage and rate dependent skin
Interference Tests	2	Monitor pressure response in monitoring well (1-27) to long term injection rate changes in I/W well	12 hours after rate change	Determine formation continuity, areal average transmissivity and storativity
Injection/ Flow Cycle Tests	2 or 3 [1]	Monitor pressure response, water production and native gas production during repeated injection and withdrawal cycles	3-4 days	Determine reservoir response to simulated short term CAES operation, especially in terms of native gas production

Notes:
MMscfd = million standard cubic feet per day
1. An additional injection and flow test using ambient air may be conducted after completing testing with oxygen-depleted air.

A graph depicting the scheduled phases of the compression testing program and anticipated injection and flow rates is provided below in Figure H-1.

Figure H-1
King Island Compression Testing Program



Operating pressures and flow rates for the compression test program are in summarized in Table H-3, below.

TABLE H-3: COMPRESSION TEST OPERATING CONDITIONS

Operating Parameter	Measurement Location	Approximate Value
Maximum injection pressure	Well head	2,200 psig[1]
Minimum injection pressure	Well head	1,650 psig
Maximum injection pressure	Bottom hole	2,500 psia
Maximum injection flow rate	I/W well manifold	14 MMscfd
Minimum injection flow rate	I/W well manifold	4 MMscfd

Notes:
psig = pounds per square inch gauge
psia = pounds per square inch absolute
I/W = Injection/Withdrawal
MMscfd = million standard cubic feet per day
1. The maximum well head injection pressure will be set as a high pressure limit in the operating control system that cannot be exceeded.

The maximum bottom-hole injection pressure during operation of the proposed Injection/Withdrawal Well will not exceed 2,500 psi (2,200 psi wellhead pressure). This pressure will be maintained using a high pressure shut down interlock connected to the wellhead pressure sensor and incorporated into the operating control system for the injection equipment, as described in Attachment K. This maximum pressure is expected to be well below the formation parting pressure. Actual injection pressures are expected to be closer to 2,350 to 2,465 psig as determined by injection modeling.[2]

EPA requires that the Maximum Available Injection Pressure (MAIP) for an injection well be based on the verified pressure gradient minus a factor of safety, usually at least 10 percent. To that end, a step rate test will be conducted as described in Attachment I. According to the available literature, breakdown pressures measured during squeeze cementing operations may be considered as a guideline to estimate the fracture gradient until site-specific data are available. The reported breakdown pressure gradient for wells in the San Joaquin Valley between depths of 3,000 and 5,000 feet is 0.70 psi/ft (California Department of Conservation Division of Oil and Gas, 1984). A fracture gradient of 0.67 psi/foot, or approximately 3,150 psi at a depth of 4,700 feet at the proposed Injection/Withdrawal Well, was therefore estimated to be consistent with the MAIP for the Injection/Withdrawal Well, and is considered a reasonable preliminary estimate of the minimum fracture gradient. Therefore, the proposed maximum injection pressure is below the anticipated MAIP at the site.

[2] Predicted maximum bottomhole pressures for the realistic conservative case (Sh/Kl) described in Attachment A are approximately 2,465 psi.

The average bottom-hole pressure will climb steadily during the test to approximately 2,350 to 2,465 psi, with the maximum being achieved when the air bubble achieves its maximum size. Pressures during the start of injection may also be near the upper end of this range as pore water is initially displaced from the area immediately surrounding the well; however, this will be mitigated by using lower injection rates during the initial bubble building period.

The average injection rate will be approximately 14 MMscfd during bubble building, and 10 MMscfd during subsequent testing, including testing with ambient air, if conducted.

After completion of the compression test, the proposed Injection/Withdrawal Well will be shut in and will not be utilized for injection or flow without first notifying the United States Environmental Protection Agency (EPA). The air bubble left in place in the reservoir will be no greater than approximately 0.5 Bscf. The actual volume will depend on how much air is vented during Phase 4 and 5 of the compression test. If the well will be utilized in the future for injection as part of the proposed CAES program, a separate Underground Injection Control (UIC) permit application will be submitted to cover this future use.

H.3 NATURE OF ANNULAR FLUIDS

In order to protect the Injection/Withdrawal Well and Piacentine 1-27 monitoring well from potential migration of formation fluids up the well bore, and provide an additional protection against the possible intrusion of formation fluids, air, or withdrawn air mixed with formation water and natural gas into Underground Sources of Drinking Water (USDW), the annulus of these wells will be isolated using a tubing and packer system and filled with a water solution containing 4 % KCl mixed with a corrosion inhibitor and a biocide. The annular fluids in these wells will be kept pressurized to near 100 psi by injecting a nitrogen blanket in the uppermost portion of the annulus. Note that annular pressures in the Injection/Withdrawal Well may change as a result of temperature changes during injection and withdrawal of hot air. Annular pressure-temperature changes will be evaluated to verify whether they are due to thermal effects or represent a well failure. The expected magnitude of potential pressure changes due to thermal effects will be calculated prior to the beginning of injection operations and further evaluated early during the injection process. If necessary, the annular pressure will be maintained by pumping additional pressurized nitrogen into the headspace above the annular fluid, or by bleeding off nitrogen. Such adjustments and the resulting pressure changes will be recorded.

In order to distinguish annular pressure-temperature changes due to thermal effects versus well failure, the following is considered. The well annulus will be a closed system, monitored for pressure at the wellhead. As such, the nitrogen blanket on the annular fluid will behave according to Boyles Law and changes in pressure due to thermal effects can be estimated as follows:

$$\frac{P1 \times V1}{T1} = \frac{P2 \times V2}{T2}$$

Where P is pressure measured in psi(atmospheric), or psia, and T is measured in degrees Rankin

For example, with 4,500' of fluid in the annulus and 100' of nitrogen blanket, a temperature increase of 40 degrees Fahrenheit in the entire system would increase an initial wellhead pressure of 100 psia to 136 psia. This is caused by two changes in the system: the increased temperature increases the volume of the fluid slightly, and the volume of the nitrogen blanket is compressed in addition to responding to direct temperature effects. A smaller nitrogen blanket would experience a proportionately larger pressure increase.

Normal fluctuations in pressure, both up and down, are expected to occur to the annulus pressure during injection and withdrawal operations due to changes in the temperature. The normal range of these fluctuations can be estimated based on the information available at the time that the annulus is filled with fluid. A leak, however, changes the relatively fixed volume of fluid in the annulus and as a result the wellhead pressures will trend down over time. While still fluctuating somewhat due to thermal effects, in the event of a leak, pressures would never return to the previous equilibrium pressure. It is the long term trend, not the short term pressure fluctuations that would indicate an issue with the integrity of the casing, tubing, or possibly a leaking tubing packer. Therefore, annular pressure measurements will be evaluated for trends that indicate a loss of fluid volume. If such a trend is identified, it would be reported to EPA within 24 hours and further investigation would be required to determine the exact cause of the annular pressure decrease.

H.4 CHARACTERISTICS OF INJECTION FLUIDS

The medium injected into the depleted gas reservoir at King Island will be air with its oxygen content depleted to a molar concentration of approximately 5 %. This depleted air will consist of the following components:

- 94 mole % nitrogen;
- 5 mole % oxygen;
- 1 mole % argon; and
- Traces of carbon dioxide and other gases.

If a decision is made to conduct injection/withdrawal testing using ambient air, the chemical makeup of the injected fluid will be as follows:

- 78 mole % nitrogen;
- 21 mole % oxygen;
- 1 mole % argon; and
- Traces of carbon dioxide and other gases.

Since air is composed mostly of nitrogen, the compressibility of oxygen-depleted air and ambient air is essentially identical. Both gas mixtures are essentially inert to the proposed tubing and well construction materials.

The main difference between the two gas mixtures is the presence of sufficient oxygen in ambient air to allow combustion if a combustible gas is present at a concentration in excess of the lower combustible limit. This is important because even a depleted gas reservoir will contain some residual gas, the injected air will mix with residual gas in the reservoir to some extent, and if air is produced from the reservoir it will contain a small amount of natural gas. Combustion would require three components, known as the three legs of the combustion triangle: fuel, oxygen, and an ignition source. Evaluations conducted for the project indicate that the methane content in the withdrawn air stream during the Phase 3 cycle tests will be very low (less than 0.2% by volume (v/v) at the end of the second cycle test). This is significantly below the lower combustible limit for methane established for the operating conditions of the compression test (4% v/v), and combustion cannot occur. Nevertheless, only oxygen-depleted air will be injected during this phase of testing, thereby eliminating a second leg of the combustion triangle for added safety. In addition, the combustible gas content of the withdrawn air stream will be monitored continuously during testing, and a safety shut down interlock will be triggered to stop withdrawal if the combustible gas concentration reaches 5%. The monitoring and control program for the compression test is discussed in additional detail in Attachment K.

Prior to a decision to proceed with injection testing using ambient air, the data from the tests conducted using oxygen-depleted air will be evaluated to assure that such a test can be conducted safely. On a preliminary basis, it is estimated that the methane concentration in the withdrawn ambient air stream could rise as high as 0.9% by volume, still well below the lower combustible limit. As with the prior tests, the combustible gas concentration in the withdrawn air would be monitored continuously; however, the safety shut down interlock would be triggered if the combustible gas concentration in the withdrawn air stream reaches 2% to provide an additional margin of safety.

The gas fraction of the withdrawal air would consist primarily of methane with very low concentrations of ethane and propane. Although these gases are potentially combustible in high enough concentrations, they are inert with respect to the well casing and tubing materials. Gas chromatography analysis of a King Island Field gas sample showed the following constituents and concentrations. A laboratory data sheet documenting this analysis is included as Attachment H-1.

TABLE H-4: SUMMARY OF GAS CHROMATOGRAPHY ANALYSIS OF KING ISLAND GAS FIELD NATURAL GAS

Component	Concentration
Methane	91.7 %
Ethane	0.129 %
Propane	18.0 ppm
Other VOCs	Not Detected
Nitrogen	8.13 %
Carbon Dioxide	0.0138 %

Flow testing of the proposed Injection/Withdrawal Well is expected to produce a relatively small amount of formation water with the withdrawn air. Total water production may vary, but is estimated to occur at an instantaneous maximum rate less than 100 barrels of water/day, and to produce less than 500 barrels in totality for the compression test. A formation water sample was collected during drilling of an exploratory core well at the site by PG&E in March and April 2013 (Piacentine 2-27) and submitted to Zalco Laboratories in Bakersfield, California for analysis of major anions and cations (with cation/anion balance), silica, total dissolved solids, hardness, alkalinity, Langlier Index, Stiff/Davis Stability Index, total suspended solids and total organic carbon. A complete laboratory analytical report is included as Attachment H-2. No water quality analysis has ever been performed on produced water from either of the production wells (Piacentine 1-27 and Citizen Green 1), and there is no opportunity to obtain a water sample from either of these wells at this time, since the Piacentine 1-27 well is currently shut-in and the Citizen Green 1 well is not producing any water. The well and tubing materials selected for the proposed well design are appropriate to inhibit corrosion from the anticipated produced water during the course of the test.

H.5 REFERENCES

California Department of Conservation Division of Oil and Gas, 1984. Evaluation and Surveillance of Water Injection Projects. Publication No. M13, pages 11-12.

ATTACHMENT I

Formation Testing Program

CONTENTS

I.1 REQUIREMENTS

The formation testing program must be designed to obtain data on:

- Fluid pressure;
- Temperature;
- Formation parting pressure and other physical characteristics of the injection zone;
- Physical, chemical, and radiological characteristics of the formation water; and
- Physical, chemical, and radiological characteristics of the injection fluids.

I.2 CORE WELL FORMATION PROPERTIES TESTING

A full range of physical, textural, mineralogical and chemical properties of the target injection zone (Mokelumne River Formation) and overlying confining zone (Capay Shale) have been determined through petrophysical analysis of conventional core, sidewall core, and wireline logs collected from a core-well drilled by PG&E at the King Island Field in March-April 2013 (Piacentine 2-27). The data derived from these efforts to date are included in Attachment C-1 (wireline logs) and Attachment G-1 (core analysis).

During the drilling of PG&E core well Piacentine 2-27, approximately 180 feet of conventional core (4" diameter) were collected from the target injection zone (primarily sands) and overlying confining unit (primarily shale). The core was transported to CoreLab where it was slabbed, photographed, described, and underwent core spectral gamma and CT scanning. Plugs collected at 1-foot intervals from the conventional core, and 22 additional sidewall cores (SWCs), were subjected to the following routine core analyses:

- Grain density;
- Porosity;
- Horizontal permeability to air;
- Fluid saturation (water); and
- V-clay.

The following additional advanced analyses were performed on a number of samples:

- Sieve analysis (15 samples);
- Vertical permeability (15 samples);
- Porosity and permeability at four confining stresses (15 samples);
- Relative permeability (5 samples);

- Critical velocity (3 samples);
- Capillary pressure (6 samples);
- Mercury injection capillary analysis (and with confining pressure) (6 samples);
- Capillary entry pressure (shale only) (3 samples);
- Geomechanical properties, including Poisson's ratio and Young's modulus (3 samples);
- Thick wall cylinder test (3 samples);
- Scanning electron microscopy and thin section analysis (15 samples); and
- Bulk and clay x-ray diffraction (XRD) (15 samples).

In addition to standard mud logging, a comprehensive wireline open hole logging program was conducted during drilling of Piacentine 2-27 to collect information regarding formation matrix and fluid properties. The log types and information derived is summarized in the table below. A downhole thermometer was used to measure the bottom-hole temperature during each logging run, which is reported on the logs.

TABLE I-1: SUMMARY OF GEOPHYSICAL LOG TYPE AND PURPOSE

Log Type	Purpose
Sidewall coring (SWC)	Reservoir parameters. Compare routine core analysis results to those from conventional core and relate to future well SWC results.
Mud Log	Lithology, rate of penetration, gas shows.
Spontaneous Potential (SP) log	Sand layer definition, formation water salinity interpretation.
Dual induction log (DIL)	Formation water salinity, hydrocarbon indicator, water/hydrocarbon saturation (with porosity measurements).
Micro-resistivity Tool (MRT)	Flushed and invaded zone resistivity, permeability indicator.
Gamma Ray (GR) log	Shale indicator. Standard and spectral GR run, which permits more accurate V-shale determination and lithological and mineralogical analysis.
Formation Density Compensated (FDC) log	Porosity measurement, water/hydrocarbon saturation (with resistivity measurements).

Log Type	Purpose
Compensated Neutron Log (CNL)	Porosity measurement, water/hydrocarbon saturation (with resistivity measurements).
Sonic log (SL)	Formation velocity, geomechanical property determination and synthetic seismograms. Can also be used for porosity determination.
Nuclear Magnetic Resonance (NMR) log	Provides porosity divided into clay-bound water, irreducible water, and movable water. Effective porosity derived by subtracting clay-bound water. Permeability measurement.
Caliper log (CAL)	Show variations in borehole size and geometry.
Electrical Micro Imaging (EMI) log	Formation texture, sedimentary features, fractures, thin-bed and lamination characterization.
Repeat Formation Tester (RFT)	Depth-discrete formation water sampling (one sample), formation water resistivity and static reservoir pressure measurement. Characterization of formation pressure above, within and below the reservoir, reservoir water chemistry evaluation.

I.3 INJECTION/WITHDRAWAL WELL FORMATION PROPERTIES TESTING

Given the extensive logging and core analysis program instituted for the core well, it is not considered necessary to collect a conventional core in the proposed Injection/Withdrawal Well, due to its close proximity to the Piacentine 2-27 core-well. However, up to 30 sidewall cores will be collected and tested for routine reservoir parameters in order to verify properties, including the following:

- Lithologic description;
- Grain density;
- Porosity;
- Permeability to air; and
- Fluid saturation (water).

For the same reason, the electric logging program in the Injection/Withdrawal Well will be a subset of the Piacentine 2-27 logging program (in terms of the types of logs run). The electric logging program will include all of the logs noted above, except NMR and EMI. In addition, as further discussed in Section I.4, the RFT tool will be used only to obtain formation pressure measurements, but not to collect water samples. The suite of logs run from the bottom of the conductor casing (60 feet) to the bottom of the surface casing interval (600 feet) will include SP, MRT, GR and CAL. The suite of logs run from 600 feet to the full depth of the boring will include these logs, and also the DIL, FDC, CNL, SL, RFT, and SWC. Mud logging will be initiated from the bottom of the conductor casing throughout the entire drilling interval. A downhole thermometer will measure the bottom-hole temperature during each wireline logging run.

I.4 FORMATION FLUID TESTING

Formation fluid physical and chemical properties were determined through analysis of an in-situ water sample collected from the Piacentine 2-27 core-well using the RFT tool, and analyzing the sample for total dissolved solids (TDS), conductivity, major anions and cations, hardness, alkalinity, Langlier Index, Stiff/Davis Stability Index, total suspended solids and total organic carbon. The results of this analysis are included as Attachment H-2. The chemistry of the subsurface formation water was further evaluated by electric and neutron-density log interpretation as discussed in Attachment E in order to assess the depth of USDW.

During completion of the proposed Injection/Withdrawal Well, a second formation water quality sample will be collected from the injection horizon during well completion, using coiled tubing and nitrogen to unload the well of drilling fluids and induce formation water flow. Produced water samples will also be collected during operation of the compression test. The initial formation water sample and three produced water samples will be submitted to a certified analytical laboratory to be analyzed as described above. In addition, the electric and neutron-density logs of the Injection/Withdrawal Well will be evaluated to assess the vertical concentration distribution of TDS in the formation water penetrated by the new well, and the results will be used to verify and update the prior analysis as needed.

Further use of the RFT tool to collect formation water samples is not proposed because our experience with formation water sampling using the RFT tool during drilling of the core well indicates that it entails significant risk of tool and borehole loss under the conditions encountered at the King Island gas field during the drilling of the Piacentine 2-27 core well. Only a single water sample was collected. The sample took approximately 4 hours to collect and it was difficult to free the RFT tool after the sample was collected; therefore, further attempts were deemed to be too risky and expensive to proceed. In our opinion, further RFT water sampling is not prudent or warranted in light of the conditions encountered and the relatively robust evaluation that has already been completed.

I.5 FORMATION PARTING PRESSURE TESTING

As discussed in Attachment H, the maximum bottom-hole pressures at the proposed Injection/Withdrawal well are anticipated to be below the Maximum Allowable Injection Pressure (MAIP). Nevertheless, a Step Rate Test (SRT) will be conducted in order to investigate the formation parting pressure. The test will be performed in general conformance with Society of Petroleum Engineers (SPE) Paper 16798, "Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure" (Singh et al., 1987). Prior to performing the SRT, a work plan will be submitted to EPA for review and approval at least 30 days prior to the test. EPA will be notified at least

10 days prior to field work. The field schedule will need to be closely coordinated with EPA because the test will be performed with the drill rig on stand-by.

In order to avoid potential damage to the Injection/Withdrawal Well and gravel pack, the test is proposed to be performed in an open borehole prior to final completion of the well. Because the upper reservoir sands are anticipated to be relatively highly permeable, an 8 ¾-inch borehole will be drilled approximately 10 feet into the Mokelumne River Formation reservoir sands, circulated clean, and filled with 4% KCL water. A wireline pressure-temperature gauge with redundant sensors and a surface readout will be lowered 5 feet into the Mokelumne River Formation to record bottom-hole pressures and temperatures during the test. The test will be performed using 4% KCl water injection in rate steps of 2 barrels per minute bpm until the fracture gradient has been established based on a change in slope of the graphed pressure response as specified in the referenced paper. If the fracture pressure cannot be reached within the limitations of feasible injection rates, the maximum pressure response and injection rate will be noted.

The tentative field procedures are presented in detail in the drilling program included as Attachment L-1 and are summarized as follows:

1. An 8 ¾-inch bit will be used to drill to total depth.
2. After completion of logging, the hole will be cemented to approximately 30 feet above the top of the Mokelumne River Formation.
3. A 12 ¼-inch bit will be used to drill out the hole and cement to the top of the Mokelumne River Formation and a 9 5/8-inch casing will be cemented to the top of the Mokelumne River Formation.
4. An 8 ¾-inch bit will be used to drill out the shoe of the 9 5/8-inch casing and drill 10 feet into the Mokelumne River Formation.
5. Open ended drill pipe will be lowered into the hole to the top of the Mokelumne River Formation and the hole will be circulated clean with 4% KCl water.
6. At least 1,000 barrels of clean filtered 4% KCl water will be mobilized to the site and placed in storage tanks near the well site. The weight and viscosity of the fluid will be measured.
7. Before the start of the SRT test, the hole will be filled with 4% KCl water until water levels are stable. Record stabilized bottom hole pressure for 1/2 hour.
8. A pressure-temperature gauge with redundant sensors and surface read out (or duplicate pressure-temperature gauges) will be lowered into the hole and secured approximately at the mid-point of the clean, open 10 foot hole in the Mokelumne River Formation below the 9 5/8-inch casing. The bottomhole pressure will be allowed to stabilize and will be recorded for at least 30 minutes.
9. Two pump trucks will be moved in and connected to the drill pipe.

10. Step rate injection will be conducted using the 4% KCl water. The first step will be conducted at 2 bpm and each subsequent step will be increased at increments of an additional 2 bpm. Constant injection rates will be maintained during each step for a period of 30 minutes.

11. The resulting injection rates and pressures will be plotted and evaluated in accordance with SPE Paper 16798. Additional step rate increases will be implemented until at least two (and preferably three) rates plot past an identified break in slope that indicates the fracture pressure has been reached.

12. If a break in slope is not evident, continue the test as long as feasible, at a minimum until a bottom-hole pressure of at least 3,200 psi has been reached.

I.6 FALL-OFF PRESSURE TESTING

Fall of testing will be conducted in general accordance with the EPA Region 9 Falloff Testing Requirements, dated August 8, 2002. At least 30 days prior to conducting the fall off tests, a brief work plan discussing the procedures and interpretation of the tests will be submitted for EPA for review and approval. EPA will be notified at least 10 days prior to field work. The data will be used to verify the reservoir characteristics used to calculate the Zone of Endangering Influence (ZEI) in Attachment A, and to update calculations regarding the ZEI as necessary. The field schedule will need to be closely coordinated with EPA because the test following the SRT will be performed with the drill rig on stand-by, and the tests using air will need to be coordinated with the pilot testing schedule.

A fall-off test (FOT) will be conducted at the end of the step rate test described in Section I.5. If possible, the final step rate will be maintained for up to twice as long as prior steps in order to make the test data easier to interpret. After completion of the step rate test, the well will be shut in, and bottom-hole pressures and temperatures will continue to be recorded for 12 hours to measure the pressure falloff prior to retrieving the wireline pressure-temperature gauge.

Fall-off pressure testing will also be conducted on the Injection/Withdrawal Well using as part of the bubble-building phase of the injection testing program (see Attachment H). The FOTs will provide data to evaluate reservoir transmissibility, permeability (based on formation thickness), skin factor, pressures (well flowing and static), as well as show the completion conditions of the well and the presence of any boundaries reached during the injection period. Bottom-hole pressures during these tests will be measured using the permanent downhole pressure-temperature gauges installed in the Injection/Withdrawal Well (described in Attachment P).

The tests will involve an injection period (producing pressure build-up) long enough to reach radial flow conditions. Likewise, pressure will be monitored during the pressure fall-off period (following pump shut-down) for duration sufficient to reach radial flow conditions and to see the effects of any boundaries reached during the injection period.

I.7 REFERENCES

Singh, P.K., R.G. Agarwal, and L.D. Krase, 1987. Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure: Society of Petroleum Engineers Paper 16798.

ATTACHMENT P

Monitoring Program

CONTENTS

P.1 REQUIREMENTS

The monitoring requirements under 40 CFR 146.13 include the following.

- Analysis of injected fluids with sufficient frequency to yield representative data;
- Installation and use of continuous recording devices to monitor injection pressure, flow rate and volume, and the pressure on the annulus between the tubing and the long string of casing;
- A demonstration of mechanical integrity pursuant to Part 146.8 at least once every five years during the life of the well; and
- The type, number, and location of wells within the AOR to be used to monitor any migration of fluids into, and pressure in, USDWs, parameters to be measured and frequency of monitoring.

Monthly reporting requirements include:

- The physical, chemical and other relevant characteristics of injection fluids;
- Monthly average, maximum and minimum values for injection pressure, flow rate and volume, and annular pressure;
- The results of other required monitoring;
- Results of mechanical integrity tests;
- Any other test of the injection well conducted by the permittee, if required by EPA; and
- Any well rehabilitation or work-over activities.

P.2 ANALYSIS OF INJECTED FLUIDS

As described in Attachment K, the injection and withdrawal flow streams will be monitored continuously by redundant oxygen and combustible gas meters, and the results recorded every 30 seconds. Summary specifications for the sensors to be used are presented in table P-1.

TABLE P-1: CHEMICAL SENSOR INSTRUMENTATION SPECIFICATIONS

Location	Equipment	Instrument Type	Model	Precision	Accuracy	Features/Remarks
I/W Manifold near Wellhead	Hydrocarbon Analyzer 1	FID on slip stream	Baseline Modcon Series 9000	± 1% full scale	± 1% full scale	Programmable automatic or manual calibration.

Location	Equipment	Instrument Type	Model	Precision	Accuracy	Features/Remarks
I/W Manifold near Wellhead	Hydrocarbon Analyzer 2	IR Detector on slip stream	Hitech Inst. IR600 series	±2 % @ span	±2.5% of f.s.d.	Complete package with in-built pump, on-board filter, temperature and pressure correction over ambient ranges.
I/W Manifold near Wellhead	Oxygen Sensor	Zirconia sensor	Sensotec Rapidox 2100ZF	± 0.5%	± 1%	Range is <1 ppm to 100% O_2. Response time 1 to 4 seconds for a 90% response to a step change in gas compositions. Calibration using 2 or 3 user selectable gas mixtures (air is default)

Notes:
Instrument model, precision and accuracy shall be as specified or equivalent
I/W = Injection/Withdrawal
RTD = Resistance Temperature Detector
FID = Flame Ionization Detector
IR = Infrared
ppm = parts per million
LCD = Liquid Crystal Display

Injection gas samples will be collected from a sampling port in the injection/withdrawal pipe manifold near the wellhead at startup and end of the initial bubble build period with oxygen-depleted air (Phase 1), and again at the startup and end of air injection, if conducted (Phase 5). Withdrawal gas samples will be collected from the sampling port at the beginning and end of each flow test sequence during Phase 3 and 5. (See Attachment H for a detailed description of the proposed injection and withdrawal tests and phases.) In addition, grab samples of injection and/or withdrawal gas will be collected weekly and screened using portable field analyzers. Additional sampling will include vent stack samples for air emissions compliance monitoring, and sampling of produced water. The planned sampling and analysis activities are summarized in Table P-2.

TABLE P-2: SAMPLING AND ANALYSIS REQUIREMENTS

Sampling Area	Sampling Location	Sampling Frequency	Sample Matrix	Sampling Method	Laboratory Analysis								Field Instrument Analysis							
					Air/ Gas			Water					Air				Water			
					Hydrocarbon Gases (C_1-C_6)	Total hydrocarbon vapors as Methane	Fixed gases (O_2, N_2, CO_2, Ar)	CAM 17 Metals	TPPH	TEPH	Major Cations/Anions	General Minerals	LEL	Total hydrocarbon vapors as Methane	O_2	H_2S	pH	Temp	Specific Conductance	Turbidity
Injection/ With-drawal Pipeline Manifold	Gas Sampling Port	Daily during injection	N_2	Grab											X					
		Daily during flow	Gas	Grab									X	X	X	X				
		At Startup, End of Bubble Build	N_2	Summa			X													
		Start/End of Flow Tests	Gas	Summa	X	X	X						X	X	X	X				
Test Separator	Water Sampling Port	At Start and End of Flow	H_2O	Spigot: Grab and Bottles							X	X					X	X	X	X
Water Storage Tank	Water Sampling Port	At Start and End of Flow	H_2O	Spigot: Grab and Bottles				X	X	X							X	X	X	X
Vent Stack	Vent Stack Sampling Port	At Start and End of Flow	Gas	Summa	X	X														

Notes:
N_2 = Oxygen-depleted air
H_2O = Water
TPPH = Total purgeable petroleum hydrocarbons, analyzed using USEPA Method 8015M
TEPH = Total extractable petroleum hydrocarbons, analyzed using USEPA Method 8015M
LEL = Lower Explosive Limit

Procedures used for the collection and handling of gas and water samples collected during the compression test are summarized below in Table P-3.

TABLE P-3: SAMPLE COLLECTION AND HANDLING PROCEDURES

Sample Type	Sample Procedures	Purging	Sample Container	Handling Procedures	Documentation
Air Grab Sample	Connect re-used Teflon Tube with Swage Lock Fitting	Purge for 3 minutes, monitor O_2 and HC content continuously, collect sample	1 liter Tedlar Bag	Purge bag and tube after sampling, store for re-use.	Field Analysis Form
Gas Grab Sample	Connect re-used Teflon Tube with Swage Lock Fitting				
Air or Gas Sample from I/W Manifold	Connect new Teflon tube with Swage Lock Fitting		1 liter Summa Canister	Chain of Custody Protocol	Sample collection log, COC, Lab Report
Compliance Gas Sample at Vent Stack	Connect new Teflon tube with Swage Lock Fitting		1 liter Summa Canister	Chain of Custody Protocol	Sample collection log, COC, Lab Report
Water Sample	Collect from spigot in clean glass beaker and decant into sample containers	Purge for 30 seconds, collect sample	Lab Supplied Bottles	Put samples on ice, Chain of Custody Protocol	Sample collection log, COC, Lab Report

Notes:
O2 = Oxygen
HC = Hydrocarbon vapor
COC = Chain of custody

P.3 MONITORING AND RECORDING OF INJECTION PRESSURES, INJECTION RATES AND ANNULAR PRESSURES

As described in Attachment K and summarized in Table P-4, the injection and withdrawal stream temperature, pressure, flow rates and volumes, and the annular fluid pressure and temperature in the Injection/Withdrawal Well will be monitored continuously and recorded every 30 seconds by a central data acquisition and control system. In addition, annular and wellhead temperature and pressure will be monitored at the Piacentine 1-27 monitoring well and recorded every 30 seconds. The Piacentine 2-27 monitoring well is cemented to the surface and not perforated. It will be used only for conducting pulsed neutron logging to assess the growth of the air bubble in the subsurface and will not experience pressure increases inside the casing. Therefore, it will not be monitored for pressure or temperature.

Monitoring of wellhead and annular temperature and pressure at the Injection/Withdrawal Well and the Piacentine 1-27 well, and downhole monitoring of pressure and temperature in the Injection/Withdrawal Well, will be continued for approximately six to nine months after the completion of the approximately 90-day compression test as described further in Section P.4.

The annular fluids in these wells will be kept pressurized to near 100 psi by injecting a nitrogen blanket in the uppermost portion of the annulus. Note that annular pressures in the Injection/Withdrawal Well may change as a result of temperature changes during injection and withdrawal of hot air. Annular pressure-temperature changes will be evaluated to verify whether they are due to thermal effects or represent a well failure. The well annulus will be a closed system, monitored for pressure at the wellhead. As such, the nitrogen blanket on the annular fluid will behave according to Boyles Law and changes in pressure due to thermal effects can be estimated as follows:

$$\frac{P1 \times V1}{T1} = \frac{P2 \times V2}{T2}$$

Where P is pressure measured in psi(atmospheric), or psia, and T is measured in degrees Rankin

For example, with 4,500' of fluid in the annulus and 100' of nitrogen blanket, a temperature increase of 40 degrees Fahrenheit in the entire system would increase an initial wellhead pressure of 100 psia to 136 psia. This is caused by two changes in the system: the increased temperature increases the volume of the fluid slightly, and the volume of the nitrogen blanket is compressed in addition to responding to direct temperature effects. A smaller nitrogen blanket would experience a proportionately larger pressure increase.

Normal fluctuations in pressure, both up and down, are expected to occur to the annulus pressure during injection and withdrawal operations due to changes in the temperature. The normal range of these fluctuations can be estimated based on the information available at the time that the annulus is filled with fluid. A leak, however, changes the relatively fixed volume of fluid in the annulus and as a result the wellhead pressures will trend down over time. While still fluctuating somewhat due to thermal effects, in the event of a leak, pressures would never return to the previous equilibrium pressure. It is the long term trend, not the short term pressure fluctuations that would indicate an issue with the integrity of the casing, tubing, or possibly a leaking tubing packer. Therefore, annular pressure measurements will be evaluated for trends that indicate a loss of fluid volume. If such a trend is identified, it would be reported to EPA within 24 hours and further investigation would be required to determine the exact cause of the annular pressure decrease.

If necessary, the annular pressure will be maintained by pumping additional pressurized nitrogen into the headspace above the annular fluid, or by bleeding off nitrogen. Such adjustments and the resulting pressure changes will be recorded. A substantial pressure loss that is unrelated to thermal effects will be assumed to be related to a leak in the well, tubing or annulus. "Normal" pressure fluctuations are expected to occur due to changes in the thermal conditions of the annulus. The magnitude of those changes will depend on the relative volumes of the fluid and nitrogen blanket in the annulus. The range of pressure fluctuations due to changing temperature conditions during operations will be recorded during the injection/withdrawal test period. Keeping in mind that the nitrogen volume will be very small compared to the annular fluid, the effect on the annulus pressure from a change in the fluid volume will be magnified considerably. For this reason a reduction by 30% of the previously recorded low pressure during operations would be considered "substantial" and require further investigation.

TABLE P-4: PRESSURE, TEMPERATURE AND FLOW SENSOR INSTRUMENTATION SPECIFICATIONS

Location	Equipment	Instrument Type	Model	Precision	Accuracy	Features/Remarks
I/W Well Wellhead	Wellhead PT Sensors	Piezoresistive Pressure Transducer	SPIDR	0.01% full scale	0.01 psi	Pressure measured by connecting oil filled steel capillary tubing; Temp via external sensor.
		Platinum Wire RTD		<0.01°F	± 001°F	
Piacentine 1-27 Well Wellhead	Wellhead PT Sensors	Piezoresistive Pressure Transducer	SPIDR	0.01% full scale	0.01 psi	Pressure measured by connecting oil filled steel capillary tubing; Temp via external sensor. Will be connected to a wireless transmitter at the wellhead.
		Platinum Wire RTD		<0.01°F	± 001°F	
Injection Pipe near I/W Well Manifold and Flow Pipe near Test Separator	PT/Flow Meter	Differential Pressure Flow Meter	ABB Totalflow Division X-series		Pressure: 0.05% of User Calibrated Spans from 20% to 100% of URL	Integral multi-variable transducer to measure differential pressure, static pressure and temperature. Module calculates flow and can store and/or transmit data. Internal battery that can be solar charged for unattended operation. Automation, control, alarming and data logging capability. Up to 180+ days of hourly /daily data records.
					Temperature:± 0.35°F over operating range from factory; ± 0.2°F repeatability over operating range after single point field calibration	

Notes:
Instrument model, precision and accuracy shall be as specified or equivalent
I/W = Injection/Withdrawal
psi = pounds per square inch
°F = degrees Farenheit
RTD = Resistance Temperature Detector
LCD = Liquid Crystal Display

P.4 MECHANICAL INTEGRITY TESTING

Prior to using the proposed Injection/Withdrawal Well for air injection, a mechanical integrity test will be performed, consisting of a Radial Cement Bond Log to be run after well completion, and a pressure test of the annular fluids between the injection tubing and the long string casing up to 2,500 pounds per square inch (psi), as described in Attachment L-1. The pressure test will be performed by pressurizing the annular fluids and holding the pressure for 30 minutes. Pressures during the test will be recorded using the annular pressure-temperature sensors and tubing head pressure gauges. A chart recorder will be used to record the pressure response. The pressure change should not exceed five percent during the 30-minute test. EPA will be notified to witness the test. In addition, the mechanical integrity of the Piacentine 1-27 monitoring well will be validated prior to the compression test by conducting a pressure test of the annular fluids and tubing pressure in that well up to 2,500 psi, in similar fashion to the Injection/Withdrawal Well. As with the Injection/Withdrawal well, the pressure change should not exceed five percent during the test. EPA may require additional mechanical integrity tests prior to allowing injection, depending on the results of the formation Step Rate Test and core testing results (Attachment I).

The integrity of the injection process will be further validated using a thermal decay log and a spinner log of the Injection/Withdrawal Well. This test is proposed to be delayed slightly beyond 60 days so as not to interrupt the relatively brief 90-day compression testing schedule. Since use of the well will be limited to the short term compression test, delaying the test for approximately 30 days will not increase the risk of well failure. Because the medium being injected is air, a tracer test is not proposed to be conducted. EPA will be provided with a work plan detailing the approach to this test at least 30 days prior to implementation.

A failure of any mechanical integrity test will be reported to EPA within 24 hours as required under 40 CFR 144.51(k)(6).

The Injection/Withdrawal Well will be used to perform injection and flow testing for a period of approximately 90 days, after which the Injection/Withdrawal Well and the Piacentine 1-27 and 2-27 monitoring wells will be shut in, and the post-test monitoring period will be initiated. The post-test monitoring period will continue for a period of 6-9 months, unless EPA determines that a longer monitoring period is required based on the final measurements at the end of the post-test monitoring period.

During the compression test, a downhole packer and tubing assembly will be installed in the Piacentine 1-27 well. The packer will be installed such that the annulus between the tubing and casing will be isolated and will only be subject to higher pressures if there is a leak in the packer or within the tubing string. The wellhead pressures (tubing and annulus) will be monitored on a daily basis, both during the compression test and the post-test monitoring period until the well is abandoned or operation/responsibility for the well is returned to the original owner. Any leakage between the tubing and casing, or through the packer, will be detectable by changes in the annulus pressures measured at the wellhead. Corrective action will be taken to determine the source of the leakage and to remediate the problem. The wellhead pressures will be included in the monthly report provided to EPA. Mechanical Integrity Testing will not be performed on the well during this time.

In addition, wellhead pressures at Citizen Green 1 will be monitored during the compression test. Static bottomhole pressure will be measured in the Citizen Green 1 only before the compression test. During the post-test monitoring period, only wellhead pressures will be monitored at this well (Citizen Green 1 will be returned to active status and therefore bottomhole pressure measurements will be difficult to obtain). As with Piacentine 1-27, this data will be recorded daily and will be included in the monthly report provided to EPA.

If at the end of the post-test monitoring period the bottomhole pressures in the Injection/Withdrawal Well are below the normal hydrostatic gradient, the Injection/Withdrawal Well will be maintained in an inactive status with monitoring and mechanical integrity testing performed every two years at a minimum in order to maintain the well in that status. If the bottomhole pressures in the Injection/Withdrawal well exceed the normal hydrostatic gradient at the end of the post-test monitoring period, the well will be plugged and abandoned in accordance with EPA requirements as described in Attachment Q. Under this circumstance, the well would not be subject to further monitoring or mechanical integrity testing.

Ownership of the Piacentine 1-27 and 2-27 monitoring wells will be turned over to the field operator after the conclusion of the post-test monitoring period. PG&E will work with the field operator to meet any EPA requirements regarding these wells after the transfer of ownership. It is assumed that if the bottomhole pressures in these wells falls below the normal hydrostatic gradient after transfer of ownership, the wells would revert back to DOGGR jurisdiction, as they are currently.

P.5 MONITORING AND REPORTING

Prior to the start of the test, bottomhole pressure measurements will be obtained from the Piacentine 1-27 well and the Citizen Green 1 well.

The following parameters will be recorded daily and reported to EPA in monthly reports until the compression test is completed:

- Injection pressure, temperature flow rate, oxygen content, and total injected volume;
- Withdrawal pressure, temperature, flow rate, combustible gas content, and total withdrawn volume;
- Shut-in pressure and temperature for the Injection/Withdrawal Well and Piacentine 1-27; and
- Wellhead tubing and annular pressure in the Injection/Withdrawal Well, Piacentine 1-27 and Citizen Green 1.

In addition, the following information will be provided:

- Injection air chemical analysis results (for fixed gases);
- Withdrawal air chemical analysis results, as applicable (for fixed gases, combustible hydrocarbons and volatile organic compounds);
- Produced water chemical analysis results and disposal documentation, as applicable;

- Monitoring wellhead pressure and temperature readings;
- Downhole temperature and pressure readings, when recorded;
- The results of Mechanical Integrity Tests;
- The results of Falloff Tests;
- The results of Step Rate Tests;
- Any shut down events; and
- Any well maintenance or work-over activities.

Because it is not practicable, monitoring of downhole pressures in Citizen Green 1 will not be performed once the well has been returned to gas production after completion of the compression test.

The reports will include an assessment comparing the measured results to design performance parameters and expected reservoir behavior.

P.6 RECORD KEEPING

Complete records from the above monitoring will be maintained by PG&E for the Injection/Withdrawal Well and compression test until at least 5 years after plugging and abandonment of the Injection/Withdrawal Well. In addition, calibration and maintenance records will be maintained for all equipment. These records will only be discarded after written notification to, and approval from, EPA.