Technical Feasibility of Compressed Air Energy Storage (CAES) Utilizing a Porous Rock Reservoir

Final Report

March 2018

Report Number DOE-PGE-00198-1

Prepared by

Pacific Gas & Electric Company

San Francisco, CA 94105

Authors
Michael Medeiros, Robert Booth, James Fairchild, Doug Imperato, Charles Stinson, Mark Ausburn, Mike Tietze, Saeed Irani, Alan Burzlaff, Hal Moore, James Day, Ben Jordan, Trent Holsey, Doug Davy, Kevin Plourde

For the United States Department of Energy under Contract DOE-OE0000198, Executed December 2009

And, the California Public Utilities Commission under Decision 10-01-025, Executed January 2010

And, the California Energy Commission under Grant Award PIR-12-001, Executed July 2013

Principal Investigator

Michael Medeiros, Program Manager, Pacific Gas & Electric Company, mjml@pge.com

Acknowledgments

We would like to acknowledge the many organizations and individuals who contributed their time and unique expertise to the overall Compressed Air Energy Storage (CAES) Study effort and in creating the basis for this final report. These included PG&E contractors Worley Parsons, MHA Petroleum Consultants, Irani Engineering, Vox Planning, CH2M Hill, Hal Moore Energy Consulting Services, Bluewater Energy Solutions, Day Carter Murphy LLP, King Island Gas Storage, Robert Booth, James Fairchild, Doug Imperato, and Charles Stinson. As well, we would like to acknowledge Lawrence Berkeley National Labs and the public agencies of San Joaquin County and the City of Lodi for their contributions and support. Reviewing and editing by Jonas Weisel are also gratefully acknowledged.

Citation

Medeiros, M, Booth, R, Fairchild, J, Imperato, D, Stinson, C, Ausburn, M, Tietze, M, Irani, S, Burzlaff, A, Moore, H, Day, J, Jordan, B, Holsey, T, Davy, D, Plourde, K. 2018. Technical Feasibility of Compressed Air Energy Storage (CAES) Utilizing a Porous Rock Reservoir, Final Report. DOE-PGE-00198-1. Pacific Gas & Electric Company, San Francisco, CA, March 2018.

Legal Disclaimer

Abstract

Pacific Gas & Electric Company (PG&E) conducted a project to explore the viability of underground compressed air energy storage (CAES) technology.

CAES uses low-cost, off-peak electricity to compress air into a storage system in an underground space such as a rock formation or salt cavern. When electricity is needed, the air is withdrawn and used to drive a generator for electricity production.

The project screened potential sites in California and selected two locations: King Island, near Stockton, and East Island in San Joaquin County. All necessary rights were acquired at both sites to conduct tests and develop a CAES facility. Core drilling provided information on reservoir rock properties, caprock properties, reservoir pressure, and reservoir fluid. Results found the conditions at the King Island site to be more favorable than East Island. Air injection testing at King Island produced data on flow dynamics, rock mechanics, and other factors. Finally, the project team developed a conceptual engineering design for a CAES facility and reservoir infrastructure, and analyzed the environmental impacts and permitting requirements.

To determine the interest and qualifications of potential third parties, the project issued a Request for Offer (RFO), which required applicants to describe their technical qualifications to develop, construct, own, operate, and maintain a CAES facility at the King Island site, and to estimate their costs for participation in the project. Offers were received, but the best offer was not economically competitive with alternative storage technologies.

The project demonstrated the technical feasibility of using an abandoned natural gas reservoir for storing high-pressure compressed air for a 300-MW-by-10-hour CAES facility. The reservoir at the King Island site was shown to be capable of accommodating the flow rates and pressures necessary for the operation of the facility. However, the estimated high cost of a CAES facility will have to be addressed in the context of the cost of alternative energy storage technologies.

Table of Contents

Appendices

Appendix 3A, Attachment 1, Cache Slough Site Selection and Attachments.

Appendix 3A, Attachment 2, Crossroads Site Selection and Attachments.

Appendix 3A, Attachment 3, McMullin Ranch Site Selection and Attachments.

Appendix 3A, Attachment 4, Merrill Avenue Site Selection and Attachments.

Appendix 3A, Attachment 5, Perkins Lake Site Selection and Attachments.

Appendix 3A, Attachment 6, Putah Sink Site Selection and Attachments.

Appendix 3A, Attachment 7, Tracy Site Selection and Attachments.

Appendix 3A, Attachment 8, West Thornton Site Selection and Attachments.

Appendix 3A, Attachment 9, Willow Slough Site Selection and Attachments.

Appendix 3A, Attachment 10, Zamora Site Selection and Attachments.

Appendix 3A, Attachment 11, 111019, Screening CAES Model GIPtoWVol.pdf.

Appendix 3A, Attachment 12, 120127, Evaluation Summary Composite.xls.

Appendix 3A, Attachment 13, 120822, Evaluation Summary Composite.xls.

Appendix 3A, Attachment 14, CAES High Level Review.docx.

Appendix 3A, Attachment 15, CAES Reservoir Size Determination.pdf.

Appendix 3A, Attachment 16, East Islands Cultural Final No Records.pdf.

Appendix 3A, Attachment 17, East Islands BCA Final.pdf.

Appendix 3A, Attachment 18, King Cultural Final No Records.pdf.

Appendix 3A, Attachment 19, King Island BCA Final.pdf.

Appendix 3A, Attachment 20, Master List.xlsx.

Appendix 3A, Attachment 21, PG&E CAES Gas Screening Model, November 2011.

Appendix 4A, Attachment 1, SmartCAES Suggested Arrangement.pdf.

Appendix 5A, Attachment 1, AMMs and Mitigation Measures.docx.

Appendix 5A, Attachment 2, CAES CoreRecom—East and King.pdf.

Appendix 5A, Attachment 3, Core Analysis Requirements.xls.

Appendix 5A, Attachment 4, Core Description Morais 2-16-20 Apr 2013.pdf.

Appendix 5A, Attachment 5, CoreSummary Piacentine 2-27 rev 26 June 2013 final.docx.

Appendix 5A, Attachment 6, East Island, Reservoir Characterization and Analysis of Suitability for CAES.pdf.

Appendix 5A, Attachment 7, East Island Cultural Final No Records.pdf.

Appendix 5A, Attachment 8, East Island Map.

Appendix 5A, Attachment 9, East Island BCA Final.pdf.

Appendix 5A, Attachment 10, East Islands Drilling Program.docx.

Appendix 5A, Attachment 11, EM513082PG Piacentine 2-27 Geochem Final 4-29-13.pdf.

Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf.

Appendix 5A, Attachment 13, King Island Map.

Appendix 5A, Attachment 14, King Island Cultural Final No Records.pdf.

Appendix 5A, Attachment 15, Kings Island BCA Final.pdf.

Appendix 5A, Attachment 16, MORIAS 16-2 RDT Transient Pressures.pdf.

Appendix 5A, Attachment 17, Morais 16-2 Well Summary Report, 4-15-2013.pdf.

Appendix 5A, Attachment 18, PG&E EQ Interim Action Memorandum King-East-Cache.pdf

Appendix 5A, Attachment 19, PGE MORAIS 16-2 612-0397.pdf.

Appendix 5A, Attachment 20, PGE PIACENTINE 2-27 612-0396.pdf

Appendix 5A, Attachment 21, Piacentine 2-27 Drilling Program.docm.

Appendix 5A, Attachment 22, Piacentine 2-27 Well Summary Report.pdf.

Appendix 5A, Attachment 23, PIACENTINE 2-27 RDT Survey Pressures.doc

Appendix 5A, Attachment 24, Summary logging and coring program 2Fields ACTUAL.xls.

Appendix 6A, Attachment 1, Final Tech Memo for CAES, Reservoir Characterization and Full Field Development Model.pdf.

Appendix 6A, Attachment 2, Flammability characteristics of combustible gases and vapors Bureau of Mines.pdf.

Appendix 6A, Attachment 3, Limiting Oxygen – Impacts on Flammability.pdf.

Appendix 6A, Attachment 4, Methane LFL as function of progress.pdf.

Appendix 6A, Attachment 5, USBM-680 Investigation of Fire & Explosion.pdf.

Appendix 7A, Attachment 1, Electric Transmission.

Appendix 7A, Attachment 2, WP Conceptual Design Addendum Alt ATS.

Appendix 7A, Attachment 3, WP Conceptual Design Addendum Alt ECF Site.

Appendix 7A, Attachment 4, WP Conceptual Design ATS.

Appendix 7A, Attachment 5, WP Conceptual Design ECF.

Appendix 7A, Attachment 6, CAES Final Tech Memo FINAL 25 Sept 2015 Rev 0 Full.

Appendix 7A, Attachment 7, King Island Progress Report 01-29-2014 FullField.pdf.

Appendix 7A, Attachment 8, King Island Progress Report 09-03-2014 FullField Case 3B1.pdf.

Appendix 7A, Attachment 9, King Island Progress Report 09-10-2014 FullField Case 4B1.pdf.

Appendix 8A, Attachment 1, Final Environmental Assessment Appendices.pdf.

Appendix 8A, Attachment 2, Final Environmental Assessment.pdf.

Appendix 8A, Attachment 3, Finding of No Significant Impact.pdf.

Appendix 8A, Attachment 4, KICP Appendix 5.3E SWCA GeoTest 2012.pdf.

Appendix 8A, Attachment 5, KICP Appendix 5.3F CompTest 05.31.2013.pdf.

Appendix 8A, Attachment 6, KICP Appendix 5.3G Subsurface Testing KICP Compression.pdf.

Appendix 8A, Attachment 7, ESLPA Final Volume 1 Document.pdf.

Appendix 8A, Attachment 8, ESLPA Final Volume 2 Appendices.pdf.

Appendix 9A, Attachment 1, CAES Offer Form.

Appendix 9A, Attachment 2, CAES Term Sheet.

Appendix 9A, Attachment 3, Resource Adequacy Only Term Sheet.

Appendix 9A, Attachment 4, Capacity Storage Term Sheet.

Appendix 9A, Attachment 5, RFO Protocol.

Figures

Tables

Chapter 1
Executive Summary

1.1 INTRODUCTION

In coming years, Pacific Gas & Electric Company (PG&E) is facing a substantial increase in renewable generation and will need to continue investigating promising technologies that could provide operational flexibility for power grid scheduling.

To help meet this need, PG&E launched a project to explore the viability of underground compressed air energy storage (CAES) technology.

CAES is an energy storage and generation technology. The technology uses low-cost, off-peak electricity to compress air into a storage system. When electricity is needed, the air is withdrawn and used to drive a generator for electricity production. The compressed air may be stored in several types of underground media, which include saline porous rock formations, depleted gas or oil fields, and salt caverns. For California, CAES could play a particularly significant role in integrating intermittent renewable resources and balancing supply and demand.

PG&E's CAES project was planned to proceed in three phases: (1) project definition and compliance; (2) plant construction, commissioning, and operation; and (3) plant monitoring and technology transfer. This report describes the work undertaken in Phase 1.

The key objectives of the overall project, along with evaluating commercial and economic feasibility, were to:

1. Verify the technical performance of advanced CAES technology using a porous rock formation as the underground storage reservoir.
2. Integrate intermittent renewable resources by using the CAES plant to provide ramping/regulation to steady the power fluctuations from load and intermittent renewables.
3. Confirm use of the CAES plant to provide emergency spinning/non-spinning reserve (synchronous and non-synchronous).
4. Confirm use of the CAES plant to perform Volt-Amperes Reactive (VAR)/voltage support.

1.2 PROJECT DEVELOPMENT

The development of the CAES project followed seven steps:

1. Identification of underground storage reservoir
2. Site control
3. Core drilling
4. Air injection testing
5. CAES plant design
6. Environmental impacts
7. Commercial and economic feasibility

1.2.1 Identification of Underground Storage Reservoir

Initially the project team identified a site for the CAES project in a depleted gas field in the Buttonwillow area of California. However, after further review and analysis, the site was eliminated due to low reservoir pressure, a reservoir size that would have required higher development costs, and existing wells that may not have been properly abandoned and would require high remediation costs.

Subsequently PG&E sought to determine the best viable site by initiating a reservoir screening process. This process included geological factors such as reservoir size, permeability, porosity, depth/pressure, reservoir thickness, remaining reserves, and trapping mechanism. Screening also considered historical factors (number and type of wells, age of wells, and abandonment history) and environmental issues (land-use zoning, proximity to sensitive areas, and local community issues). In addition, the project team developed a cost evaluation model to assist in tracking the economic pros and cons of various reservoir locations.

The screening process led to the selection of two sites, which were judged to have the best potential for CAES development: King Island, near Stockton, California, and East Island, in San Joaquin County.

1.2.2 Site Control

Once the two possible reservoir sites were identified, PG&E began efforts aimed at obtaining site control at the two locations. These efforts included the acquisition of all the rights necessary to conduct the testing (core drilling and air injection) and to allow for the development, construction, and operation of a CAES facility. Discussions were undertaken with the various third-party holders of the rights to the properties required for the Energy Conversion Facility (ECF), well-pad facilities, and all required linears (air pipeline, water pipeline, etc.).

1.2.3 Core Drilling

To this point, the two sites at King Island and East Island had been modeled with publicly available, and not always complete, data. To obtain high-quality, targeted data, PG&E elected to drill one core well into each reservoir for the purpose of obtaining core samples, which could be analyzed in the laboratory for specific reservoir properties. These core samples improved the geological database and provided information on reservoir rock properties, caprock properties, reservoir pressure, and reservoir fluid. Based on test results, the horizontal, vertical, and caprock permeability of the King Island well were found to be favorable and more viable than the East Island well.

1.2.4 Air Injection Testing

Air injection test was subsequently conducted at the King Island reservoir to prove the feasibility of utilizing a depleted natural gas reservoir for a CAES application.

The air injection testing program provided important data regarding how the reservoir responded to air injection, in terms of flow dynamics, rock mechanics, and the percentage of native gas in the withdrawal stream. A reservoir developed for a CAES project is expected to perform essentially the same as an underground natural gas storage reservoir, except for the effects of injected air on the reservoir. The air could change rock properties over time, which in turn could affect the reservoir's effectiveness in storing compressed air. A testing program, therefore, was needed to answer the questions that regulators, developers, operators, and potential financial participants may have in regards to the reservoir.

The air injection testing built an air bubble of approximately 500 million standard cubic feet (MMscf). A series of injection and withdrawal tests were conducted to mimic the expected operation of a fully developed project. The test results were then utilized to help forecast the operational and economic performance of the project.

1.2.5 CAES Plant Design

PG&E developed a conceptual engineering design for a CAES facility and the reservoir infrastructure at the King Island site.

To develop this design, the project team evaluated two technologies: GTCAES and SMARTCAES™. GTCAES utilizes a conventional gas turbine's exhaust thermal energy to heat the compressed air. It is a modified Brayton cycle similar in configuration to a combined-cycle power plant. SMARTCAES™ utilizes two turbo-expanders in series on a single shaft driving an electric generator to generate electricity. In a reheat recuperative configuration, the waste heat from the low-pressure turbo-expander is captured to heat the compressed air prior to the high-pressure combustors, raising the temperature to 1000ºF before entering the HP turbo-expander, which exhausts to the LP combustors, increasing the temperature above 1600ºF and expanding to the recuperator.

The evaluation led to the choice of SMARTCAES™. Analyses were then conducted to compare wet versus dry cooling for the air compression plant and a compression cycle of 6 versus 12 hours. Conceptual designs were then formulated and costs estimated for the Energy Conversion Facility and the Air Transmission System.

1.2.6 Environmental Impacts

An analysis was conducted of the federal, state, and local environmental considerations and permitting requirements for the surface facilities (Energy Conversion Facility, well pads, pipelines, and major electrical systems) and the reservoir (including the injection/withdrawal wells and ancillary equipment). These considerations included air quality, biological resources, cultural resources, geological hazards and resources, hazardous materials handling, land use, noise, paleontological resources, public health, socioeconomics, soils, traffic and transportation, visual resources, waste management, water resources, and worker health and safety.

1.2.7 Commercial and Economic Feasibility

A Request for Offer (RFO) process was conducted in 2015 and 2016 to determine the interest and qualifications of potential third parties to develop, construct, own, operate, and maintain a CAES facility, and to seek associated bids. The RFO process and its results were intended to assist PG&E in determining the technical capabilities of independent market participants to undertake the development of a CAES facility in California; to provide the market's perspective on the cost of developing, owning, and operating a CAES facility; and to allow PG&E to analyze the value of the CAES facility for grid operations based on the offerings provided.

On June 1, 2016, PG&E received the offers for the CAES RFO and began the process of performing the market valuations of the proposed projects. In general terms, the best offer received was not competitive with the executed storage contracts from PG&E's 2014 storage RFO.

PG&E subsequently held discussions with the bidder of the most attractive CAES offer to understand why the capital cost implied by the bid price was significantly greater than what was estimated in the conceptual engineering and cost estimates performed for the project. The bidder revealed that the bid price was high due to a combination of factors, including: contractual financial impacts if the project operates at low availability; higher material costs due to the potential for corrosion; uncertainty in major equipment costs in 2024 (given the expected on-line date); inability of major equipment vendors to provide performance guarantees given the uncertain composition of the withdrawal air stream; incomplete knowledge of the underground characteristics of the reservoir (reservoir performance was based on test results from one well), and the resulting uncertainty over the number of reservoir wells needed for the project; operating schedule risk associated with the Buyer having the right to dispatch the project, but management of methane and oxygen depletion in withdrawal air depends upon the timing of injection and withdrawals; and permitting risk (including jurisdictional uncertainties).

Given the lack of competitive bids, the bidders were notified on August 2, 2016 that they did not make the short list, and the RFO was closed.

1.3 CONCLUSION AND RECOMMENDATIONS

The project demonstrated the technical feasibility of using an abandoned natural gas reservoir for storing high-pressure compressed air for a 300-MW-by-10-hour CAES facility. The reservoir can accommodate the flow rates and pressures necessary for the operation of the facility, but some design and operational constraints will have to be properly managed. The estimated high cost of a CAES facility will also have to be addressed in the context of the cost of alternative energy storage technologies.

The key findings of the project include:

- The air injection and withdrawal cycles must be carefully scheduled to avoid having excessive concentrations of methane in the withdrawal air stream.

- Withdrawal air from the initial cycles of the King Island reservoir is expected to be depleted in oxygen and unable to support normal operation in the CAES Energy Conversion Facility system.

- Additional wells will be needed to remove water from the reservoir during the building of the air bubble.

- Alloyed or coated steels may be needed in well materials to withstand corrosive well water.

- A CAES project at the King Island reservoir is not currently economically competitive with alternative storage technologies.

To further assess and manage the risks that come with a CAES project using a depleted natural gas reservoir reservoir, the following additional development work is recommended:

- Obtain additional core samples to help to assess the variability of key reservoir attributes (e.g., permeability, distribution of oxidizable minerals and potential precipitates) over the full extent of the reservoir.

- Complete additional I/W wells at other locations in the reservoir and then conduct additional tests to better characterize full-scale operations with respect to methane and oxygen content in the withdrawal air; produced water chemistry and the potential for scaling and corrosion; and, precipitation of iron oxide or other solids and their impacts on reservoir porosity and permeability.

- Test the Energy Conversion Facility combustor over the range of expected concentrations of methane and oxygen in the withdrawal air, and make modifications to improve the combustor's stability, emissions, and turndown capabilities. This should enable the Energy Conversion Facility equipment vendor to provide more expansive performance guarantees to a potential CAES project developer.

- Evaluate the cost and performance of adiabatic CAES technology (i.e, air compression, storage and expansion, but without firing of natural gas fuel). For projects in California, there is an energy resource "loading order" policy that provides a higher priority to investment in energy efficiency, demand response, renewable energy and distributed generation than investing in fossil fueled power plants. Given this preference, adiabatic CAES technology may be preferred over conventional CAES technology.

- Evaluate, develop and test methods for removing methane from the reservoir withdrawal air. Methane removal will be more difficult for adiabatic CAES projects because, unlike conventional CAES projects, they will not be able to use the relatively simple solution of burning it in the Energy Conversion Facility combustor.

Chapter 2
Introduction and Overview

2.1 INTRODUCTION

Compressed Air Energy Storage (CAES) is an energy storage and generation technology. The technology uses low-cost, off-peak electricity to compress air into a storage system. When electricity is needed, the air is withdrawn and used to drive a generator for electricity production.

Pacific Gas & Electric Company (PG&E) has undertaken a project to demonstrate the viability of an advanced underground CAES technology and to develop best practices to accelerate the technology's market readiness in the United States. The project was planned to proceed in three phases: (1) project definition and compliance; (2) plant construction, commissioning, and operation; and (3) plant monitoring and technology transfer.

This report describes the work undertaken in Phase 1.

Chapter 2 provides an introduction and overview to the report. Section 2.2 explains how the CAES technology works. Section 2.3 explores how CAES can contribute to management of California's power grid. Section 2.4 reviews the background to PG&E's CAES project. Section 2.5 outlines the project's scope. Section 2.6 reviews Phase 1 of the project and the contents of this report.

2.2 WHAT IS CAES?

CAES plants use electricity to compress air into an air storage system. When electricity is needed, air is withdrawn from the storage system, heated by a gas-fired burner, and run through an expansion turbine to drive an electric generator (see Figure 2-1).

In a conventional gas-fired turbine, nearly two-thirds of the energy produced by the turbine is consumed by its compressor. By comparison, a CAES plant uses compressed air to provide the air needed during the generation process, conserving natural gas. CAES plants use about 35% of the gas of a combustion turbine (CT) and thus produce about 35% of the emissions per kWh generated by a CT.

The compressed air may be stored in several types of underground media, which include saline porous rock formations, depleted gas or oil fields, and salt caverns. The air may also be stored in above-ground vessels or air pipelines.

Only two CAES plants have been built to date: a 290-MW, 4-hour unit in Huntorf, Germany, built in 1978 and expanded to 330 MW in 2008, and a 110-MW, 26-hour unit in McIntosh, Alabama, built in 1991. Both plants use underground salt caverns as the storage media.

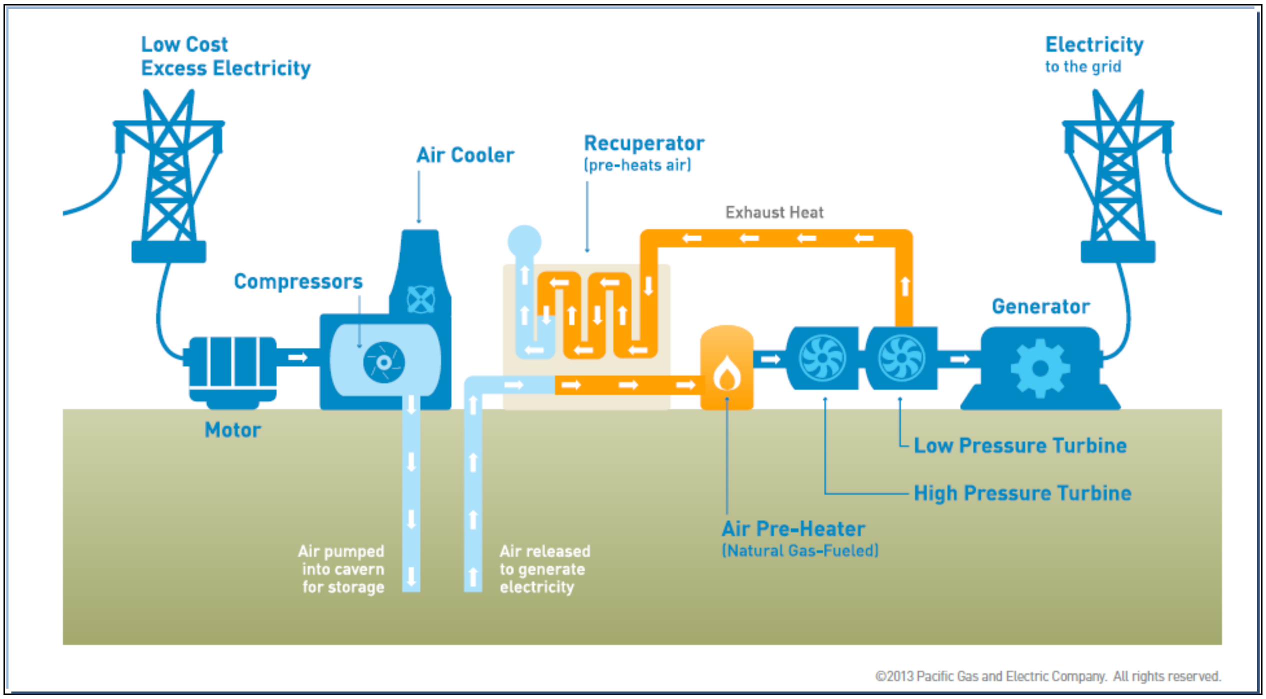


Figure 2-1 CAES System Using Underground Reservoir as Storage Medium

2.3 THE ROLE OF CAES IN MANAGING A GREEN GRID

2.3.1 Integrating Renewable Resources, Balancing Load

CAES technology offers many possible benefits, especially as utilities purchase increasing amounts of intermittent, renewable generation to meet internal goals and/or regulatory mandates.

The majority of new, renewable generation comes from two main sources: wind and solar generation. Both of these clean sources of energy are dependent on availability (the wind blowing, the sun shining), which dictates their ability to generate. For utilities with these resources in their generation mix, two issues make CAES technology a potentially valuable addition to the grid:

1. While advances in modeling have greatly increased the accuracy of predicting the generation profile of a wind and/or solar resource, sudden changes in the availability of the wind and/or sun can lead to dramatic swings in generation output (up or down).
2. Because these resources are typically dispatched as “must-take” resources (i.e., when the wind and/or sun are available, these resources produce energy onto the system that must be taken), the output may not always match system load conditions at any given time.

As an energy storage technology, CAES has the potential to address both these issues by integrating intermittent resources and helping to balance load. Grid-scale energy storage technologies could increase the reliability and “dispatchability” of the nation’s energy supply. The smart grid of the future will need energy storage to integrate intermittent renewables, provide ancillary services, manage peak demand, and relieve transmission and distribution congestion.

2.3.2 Managing Daily Load on California's Future Power Grid—the "Duck Curve"

For California, CAES could play a particularly significant role in integrating intermittent renewable resources and balancing supply and demand. California has one of the highest renewable energy mandates in the nation. In October 2015, Governor Jerry Brown signed Senate Bill 350, which requires utilities to deliver 50% of their electricity from renewable resources by 2030. Additionally, SB 32 was signed in September 2016, which set into law the statewide greenhouse gas emissions reduction target to 40% below 1990 levels by 2030.

With these initiatives in mind, the California Independent System Operator (CAISO) is including a special study in the 2016-2017 Transmission Planning Process to investigate different portfolio scenarios for meeting the state's 50% RPS goal and the potential impact renewables may have on future grid operation.

Energy storage is one type of flexible resource among many technologies that California is considering to help integrate an increased level of renewables on the grid. Energy storage, which is a form of flexible capacity, can help to address challenges from higher renewables penetration, but its cost-effectiveness as an integration solution is still unclear. Weather-sensitive intermittent resources, such as wind and solar, increase the requirement of flexible capacity to manage forecast deviations, the variability of generation and large ramping events, and the likelihood of multi-hour over generation situations when variations in generation are not aligned with customer demand.

To maintain reliability, CAISO must continuously match the demand for electricity with supply on a second-by-second basis. Historically, the ISO directed conventional, controllable power plant units to move up or down with the instantaneous or variable demand. With the growing penetration of renewables on the grid, higher levels of non-controllable, variable generation resources are present. Because of that, the ISO must direct controllable resources to match both variable demand and variable supply.

To understand the changing grid conditions in the coming years, CAISO performed a detailed analysis to see how real-time electricity net demand changes as policy initiatives are realized. In this analysis, CAISO developed "net load curves" to represent the variable portion of the load that the ISO must meet in real time. "Net load" is calculated by taking the forecasted load and subtracting the forecasted electricity production from variable generation resources—wind and solar. The net load curves capture the forecast variability.

The ISO created curves for every day of the year from 2012 to 2020 to illustrate how the net load following need varies with changing grid conditions. Figure 2-2 shows a net load curve for one day in the spring for the years 2012 to 2020. The curve shows the megawatt (MW) amounts that the ISO must follow on the y-axis over the hours of the day on the x-axis. Due to its shape, the curve is commonly known as the "duck curve."

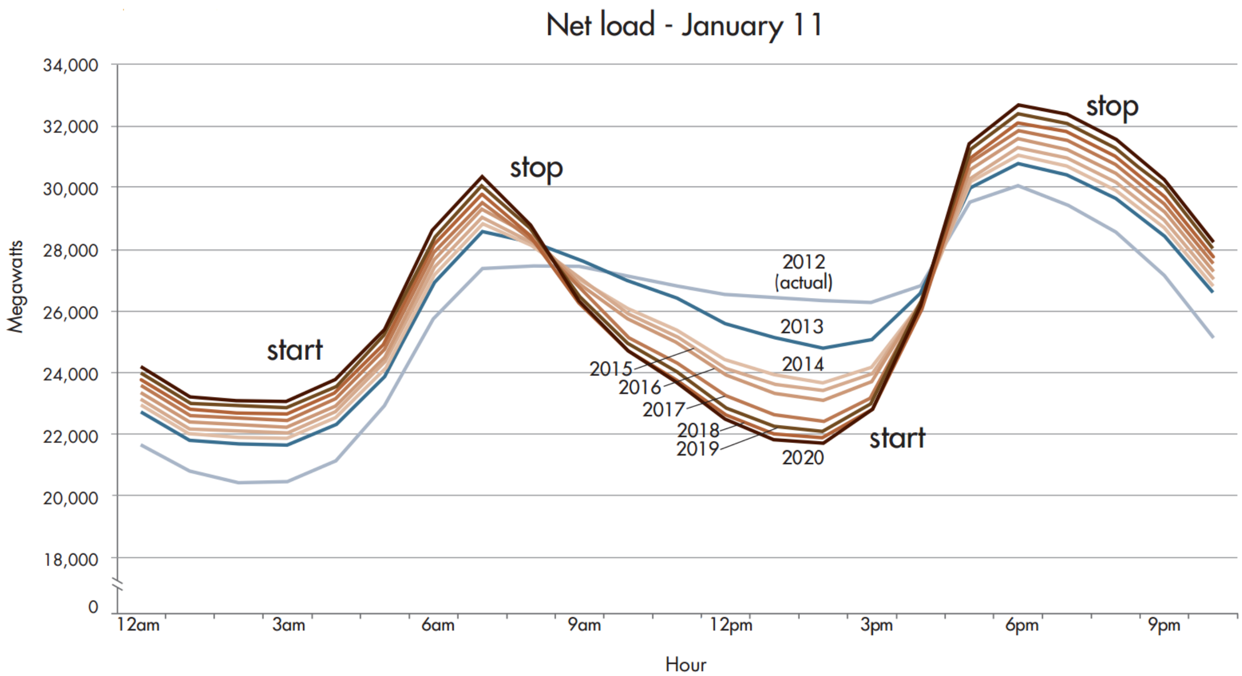


Figure 2-2 CAISO Net Load Curve for January 11 (California ISO 2015b)

The curve in Figure 2-2 reveals four distinct ramp periods:

- The first ramp of 8,000 MW in the upward direction (duck's tail) occurs in the morning starting around 4:00 a.m. as people wake up and go about their daily routine.
- The second ramp, in the downward direction, occurs after the sun comes up around 7:00 a.m. when on-line conventional generation is replaced by supply from solar generation resources (producing the belly of the duck).
- As the sun sets starting around 4:00 p.m., and solar generation ends, the ISO must dispatch resources that can meet the third, and most significant, daily, ramp (the arch of the duck's neck).
- Immediately following this steep 11,000 MW ramp up, as demand on the system deceases into the evening hours, the ISO must reduce or shut down that generation to meet the final downward ramp.

One key issue to emerge is "overgeneration," which occurs when more electricity is supplied than is needed to satisfy real-time electricity requirements. As shown in Figure 2-3, the risk of overgeneration occurs in the middle of the day.

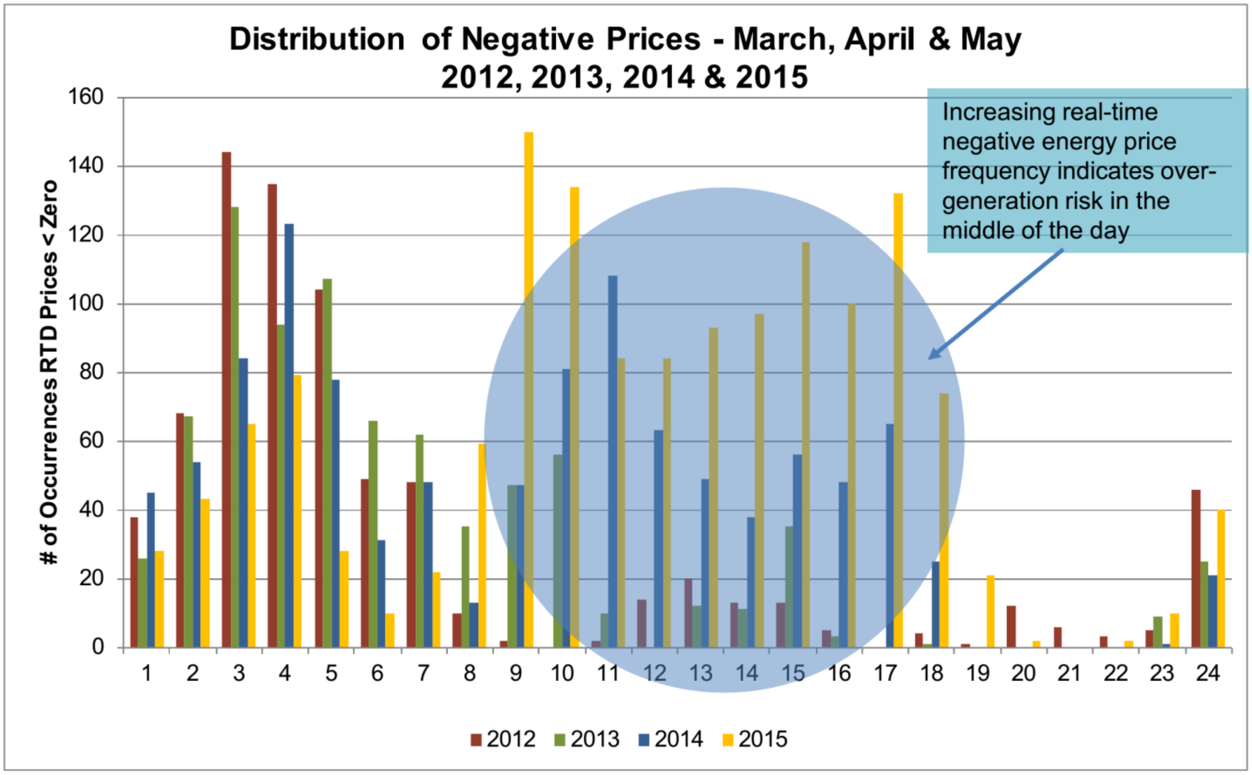


Figure 2-3 Overgeneration Occurring in the Middle of the Day (California ISO 2015a)

2.3.3 Overgeneration

A study conducted in 2013 by Energy and Environmental Economics (E3) highlights the risk of overgeneration associated with a rise in the renewable portfolio standard (RPS) in California from 33% to 50% (Energy and Environmental Economics 2013). This study finds that "overgeneration is pervasive at RPS levels above 33%, particularly when the renewable portfolio is dominated by solar resources. This occurs even after thermal generation is reduced to the minimum levels necessary to maintain reliable operations." Figure 2-4 shows how the generation mix affects the power grid throughout a 24-hour period in April 2030, with 33% RPS, 40% RPS, and 50% RPS. These graphs show the bulge of overgeneration in the middle of the day.

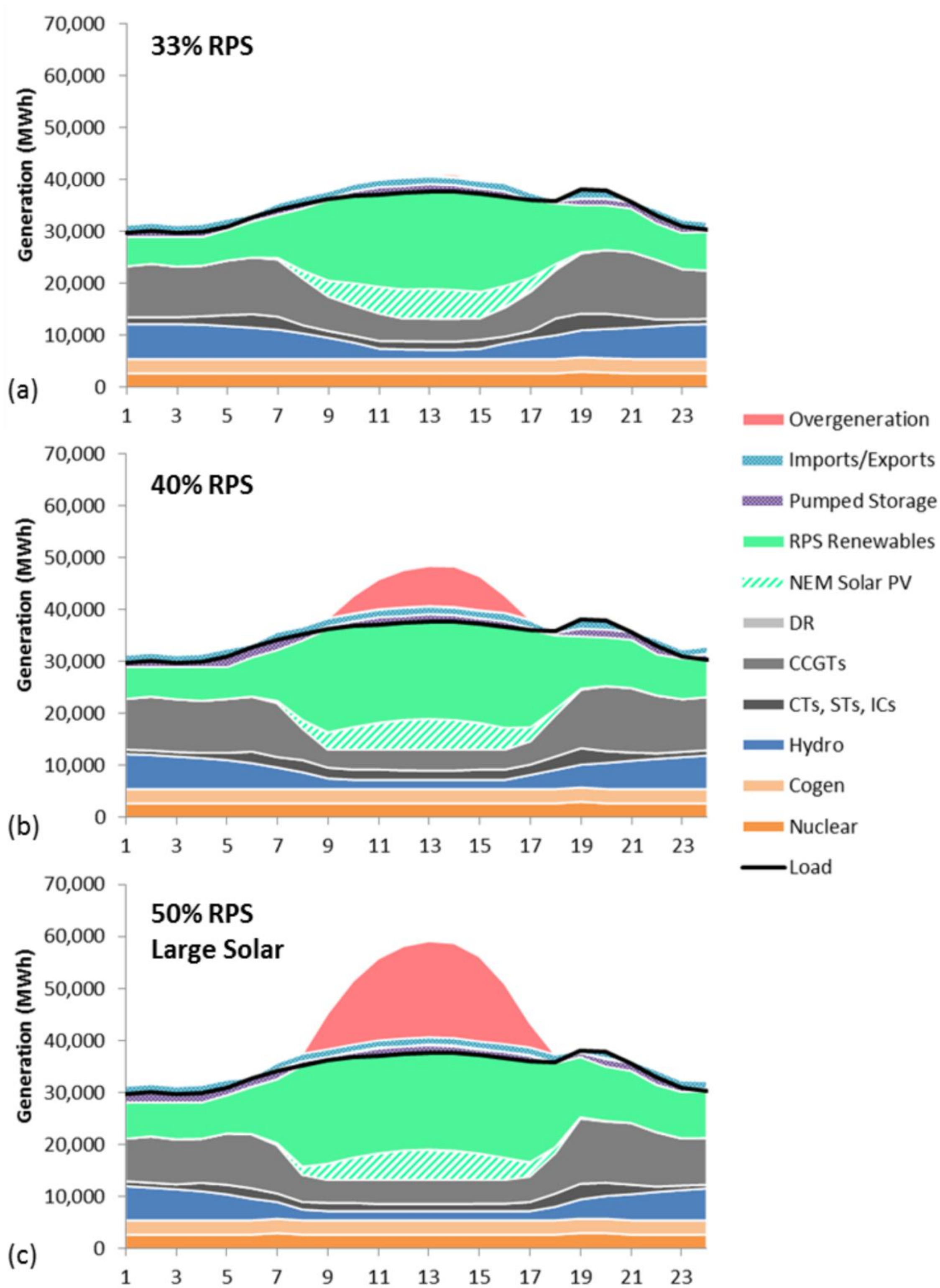


Figure 2-4 Generation Mix Calculated for April Day in 2030 with (a) 33% RPS, (b) 40% RPS, and (c) 50% RPS Large Solar Portfolios Showing Overgeneration (courtesy Energy and Environmental Economics 2014).

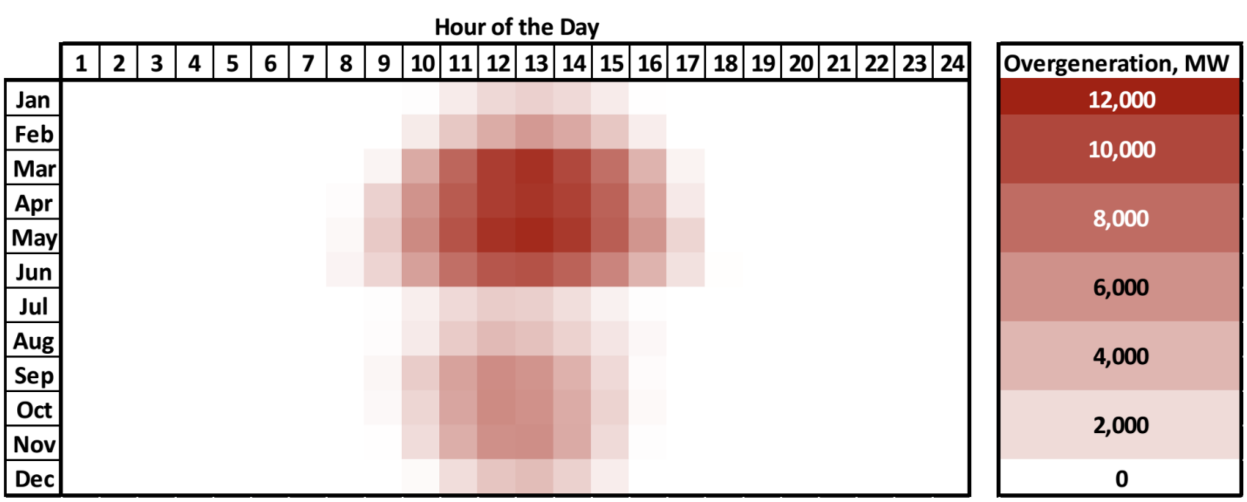
Table 2-1, which is also reproduced from the E3 report, summarizes the potential overgeneration in 2030 for the scenarios identified above. Table 2-2 shows the distribution of average hourly overgeneration by month and hour.

Table 2-1 Overgeneration Statistics for 33%, 40%, and 50% RPS Large Solar Scenarios (Energy and Environmental Economics 2014)

Overgeneration Statistics	33% RPS	40% RPS	50% RPS Large Solar
Total Overgeneration			
GWh/yr.	190	2,000	12,000
% of available RPS energy	0.2%	1.8%	8.9%
Overgeneration frequency			
Hours/yr.	140	750	2,000
Percent of hours	1.6%	8.6%	23%
Extreme Overgeneration Events			
99th Percentile (MW)	610	5,600	15,000
Maximum Observed (MW)	6,300	14,000	25,000

In scenarios with higher renewable resource penetration, this study indicates that the number of annual hours of overgeneration jumps from 1.6% to 23%, with the potential maximum megawatts in any given hour increasing from 6,300 to 25,000.

Table 2-2 Average Hourly Overgeneration by Hour/Month in 50% Large Solar Scenario (Energy and Environmental Economics 2013)



Whether or not these scenarios come to fruition, they highlight the need to take such possibilities into account when designing a facility that is flexible to operate under various scenarios.

2.3.4 The Contribution of CAES to Future Grid Management

According to CAISO, operating the future power grid in California will require flexible resources that have the capabilities to sustain upward and downward ramp, respond for a defined period of time, and change direction quickly. Importantly, too, due to the potential for overgeneration, the future power grid will require resources that can store energy or modify its use. This could be the role that new CAES resources would play in future grid management.

PG&E is California's largest public utility, operating one of the nation's cleanest energy portfolios and an industry leader in smart grid development. Facing a substantial increase in renewable generation in coming years, PG&E foresaw the need to investigate promising technologies that could modernize the nation's electric grid and provide operational flexibility.

Development of new CAES resources would continue PG&E's tradition in energy storage technology. PG&E has long recognized the important flexibility provided by large, grid-scale bulk energy storage systems. PG&E's Helms pumped storage facility, built in 1984, supplies 1,200 MW or approximately 7% of peak resource needs in California. This facility flattens out load variations on the grid, permitting PG&E's Diablo Canyon Nuclear Power Plant and other thermal power plants that provide baseload electricity to continue operating at peak efficiency. In addition, Helms helps control electrical network frequency and provide the following ancillary services: Regulation Up and Down, and Spinning/Non-spinning Reserves.

2.4 PG&E CAES PROJECT BACKGROUND

In August 2009, PG&E submitted a proposal to the United States Department of Energy (DOE), as part of its Smart Grid Demonstrations program (Funding Opportunity Announcement Number DE-FOA-0000036). This initial proposal, entitled "Advanced Underground Compressed Air Energy Storage", proposed a phased approach to building and validating the first underground compressed air energy storage (CAES) plant in California. The project would study the feasibility of a CAES plant of up to 300 MW, with 10 hours of storage, utilizing a porous rock formation as the underground storage reservoir.

The final award of $25 million of American Reinvestment and Recovery Act (ARRA) funding from the DOE was equally matched with another $25 million in December 2010 by a California Public Utilities Commission (CPUC) decision. Subsequently, in July 2013, the California Energy Commission (CEC) authorized a grant of $1 million for the project, reducing the CPUC's contribution by a like amount and keeping the total project costs at $50 million.

With the funding in place and agreement between all parties as to the project scope, work on the CAES Feasibility Study began in earnest in 2011. The project's objective was to demonstrate the viability of advanced, underground CAES technology and to develop best practices to accelerate the technology's market readiness in the United States. If all three phases are completed, the project will establish the costs and benefits of CAES, verify its technical performance, and validate system reliability and durability, at a scale that can be readily adapted and replicated around the country. The key objectives of the overall project, along with evaluating commercial and economic feasibility, were to:

1. Verify the technical performance of advanced CAES technology using a porous rock formation as the underground storage reservoir.
2. Integrate intermittent renewable resources by using the CAES plant to provide ramping/regulation to steady the power fluctuations from load and intermittent renewables.
3. Confirm use of the CAES plant to provide emergency spinning/non-spinning reserve (synchronous and non-synchronous).
4. Confirm use of the CAES plant to perform Volt-Amperes Reactive (VAR)/voltage support.

As envisioned, the project would drive measureable benefits such as reduced greenhouse gas emissions, improved grid reliability and flexibility, and lower electric power system costs.

2.5 PG&E CAES PROJECT SCOPE

The project was divided into three discrete phases:

1. **Phase 1 – Project Definition and NEPA Compliance:** This phase consisted of site selection, geologic verification, National Environmental Policy Act (NEPA) compliance, permit filing preparation, engineering, and a Request for Offers (RFO). The Phase 1 activities, analysis, and findings are the items covered by the work funded by the DOE, CPUC, and CEC, and are the subject of this Final Technical Report. Subsequent phases would be subject to the technical and economic results of the Phase 1, PG&E senior management approval to proceed, and CPUC approval of the need for the project and the reasonableness of the future costs of the project.
2. **Phase 2 – Plant Construction, Commissioning, and Operation:** This phase, which would be funded separately, would consist of CPUC approval, CEC approval, a California Independent Systems Operator (CAISO) System Impact Study, and plant construction, commissioning, and operation.
3. **Phase 3 – Plant Monitoring and Technology Transfer:** This phase would consist of two years of plant monitoring, data gathering, and analysis. White papers and publications would be issued, informing the DOE and stakeholders on the project.

Phase 1 was funded by the DOE grant and the matching funds from the CPUC and CEC. Phase 2, and subsequently Phase 3, would be subject to a Go/No-Go decision, subject to the Phase 1 results, including: identification of subcontractors and bidders, technical and economic feasibility, PG&E management acceptance and CPUC approval for full cost recovery, and other regulatory approvals and permits as necessary.

2.6 PG&E CAES PROJECT—PHASE 1

The contents of this report are organized in a manner that matches the development process followed by PG&E in seven steps:

1. Identification of underground storage reservoir
2. Site control
3. Core drilling
4. Air injection testing
5. CAES plant design
6. Environmental impacts
7. Commercial and economic feasibility

When possible, work was planned in sequential order, but as with many development projects, tasks and work were often undertaken in parallel.

2.6.1 Identification of Underground Storage Reservoir

Identification of the underground storage reservoir upon which a CAES facility could be developed was the first task. When the conceptual scope of the project was first contemplated, a depleted gas field in the Buttonwillow area of California was initially identified. However, after further review and analysis, the site was eliminated for three main issues:

1. **Low reservoir pressure.** At a pressure of approximately 1,000 pounds per square inch (psi), this reservoir pressure translates into maximum flowing pressures available at the surface during withdrawal of 800 psi or less, and declining from there throughout the withdrawal cycle. The surface equipment will require higher pressures to operate at full capacity (e.g., 950 psi or higher).
2. **Reservoir size.** At a volume of 30 billion cubic feet (BCF) (or greater), this size of reservoir would require building and maintaining a very large air bubble without any added generation capacity. This requirement would translate into higher development costs with very little incremental benefit.
3. **Existing wells.** The site was discovered in 1926, after which 85 wells were drilled in the area. Most of the field development occurred during the 1930s and 1940s, including abandonment of many wells. Well standards and record-keeping during these periods were far less rigorous than current practices. As a result, a much higher risk exists that wells were not properly abandoned and would require high remediation costs to re-abandon those wells in order for the reservoir to maintain its ability to store air for CAES.

After the Buttonwillow site was rejected, PG&E sought to locate another viable site. **Chapter 3, entitled "Reservoir Screening and Site Identification"**, describes in more detail the approach that PG&E developed and utilized to identify reservoirs that could work based on the requirements for CAES. As Chapter 3 discusses, the reservoir must also have a high likelihood to be successfully developed—i.e., consideration must be given to environmental factors as well as other key siting factors identified in Chapter 3. A good reservoir that may not receive a permit for construction and operation cannot deliver the expected important benefits.

The screening process led the project team to the selection of two sites—King Island and East Islands—which were judged to have the best potential for CAES development.

2.6.2 Site Control

Once the two reservoirs with the expected geological characteristics for CAES and with the highest probability of being developed were identified (based on technical, environmental, and economic factors), site control efforts began. As outlined in **Chapter 4, entitled "Site Control"**, site control efforts can be challenging and much more complicated than when securing site control for a traditional power facility. Chapter 4 discusses legal, commercial, and technical issues that need to be considered when siting a CAES facility.

PG&E made a strategic project decision to identify and gain site control for CAES development at not just one site, but to gain actual geological data/information from multiple sites before deciding on one site for a future air injection test and potential development. This decision was guided by two main issues:

1. **Creating Options** – PG&E reviewed other projects that focused all their efforts on one site only to determine that, based on actual testing of that one site, it contained fatal flaws and/or could not be utilized for CAES. Conducting geological testing at multiple sites would increase the probability that at least one site would have sufficient geological properties that would work for a CAES development. If the geology at all sites proved sufficient, then the best site to meet the project objectives could be selected.
2. **Time** – Related to and in conjunction with the first point, if site control was acquired for only one site and if the testing for that site proved it was unsuited for CAES, the site control and permitting effort would have to be re-started for another site. Given the time required for site control and permitting, and given that funding for this project had a "hard stop", the decision was made to acquire site control and perform initial geologic testing at multiple sites, to ensure a successful project within the given time constraints.

2.6.3 Core Drilling

Further evaluations of the two sites at King Island and East Islands were deemed necessary to refine the data such that a more robust analysis of the potential risks and opportunities could be performed. These evaluations included the drilling of one core well into each reservoir for the purpose of obtaining core samples, which could be analyzed in the laboratory for specific reservoir properties.

Chapter 5, entitled "Core Drilling, Completion, Logging, and Analysis", reviews the permitting and construction requirements associated with drilling a core well to retrieve a geological sample of the reservoirs. This chapter also discusses the types of tests conducted, the rationale for those tests, and the results of those tests at each site.

2.6.4 Air Injection Testing

The results of the core drilling allowed PG&E to make a decision to move forward with an air injection test at one of the two sites—the King Island reservoir. An air injection test, would:

1. Prove the feasibility of utilizing a depleted natural gas reservoir for a CAES application.
2. Collect sufficient data that could be used to replicate a full-scale operation, thereby minimizing some of the technical and financial risk associated with a full-scale project development.

A test of this magnitude and importance required substantial planning to ensure it was executed correctly. **Chapter 6, entitled "Air Injection Testing and Analysis"**, discusses the objective of the test; design considerations for the test including its safe operation; a description of and the rationale for the various tests to be conducted; permitting requirements; the design, construction, and operation of the temporary facility to conduct the test; and a discussion of the test results and what those results mean for the technical viability of utilizing a depleted natural gas reservoir for a CAES project.

2.6.5 CAES Plant Design

Once a decision was made to move forward with an air injection test at the King Island site, work on a preliminary engineering design for the CAES plant began. A few threshold items needed to be decided before the engineering work could begin in earnest:

1. **Selection of a CAES Technology.** Initial consideration was given to a new CAES configuration known as "Advanced CAES," or alternately "GTCAES." This configuration, yet to be employed, would utilize gas-fired combustion turbines for part of the generation output; exhaust heat would be captured and utilized to heat the reservoir air used in the expansion process to complete the CAES cycle in this configuration. The other approach is to use an updated, enhanced configuration of the current CAES equipment by Dresser Rand known as "*SMART*CAES™".
2. **Cooling Methodology.** With the potential availability of reclaimed water for cooling purposes, should the facility utilize wet cooling or dry cooling?
3. **Compression Sizing.** The size of the compression equipment influences the amount of time needed to inject a certain amount of air into the reservoir. Given system conditions, how much compression should be included in the conceptual design?

Chapter 7, "CAES Plant and Reservoir Design", looks at these items and questions. Chapter 7 looks at design considerations for the development of the King Island reservoir. It also considers the bi-directional air pipeline that would deliver air to the reservoir from the compressors and then from the reservoir back to the Energy Conversion Facility (ECF) for use in the generation process. Based on the design, the estimated costs are summarized.

2.6.6 Environmental Impacts

As with any energy project, consideration for the environmental impacts of the construction and operation must be evaluated. As discussed in Chapter 3, these factors were considered when selecting a reservoir for the project to ensure that the reservoir not only had the geological characteristics necessary for a CAES project, but that it also had the characteristics to indicate it could be permitted and operated according to environmental factors.

Chapter 8, "Environmental Siting, Licensing, and Permitting Analysis", reviews the various factors that would be considered for two distinct components of the project: 1) Surface Facilities and 2) Reservoir. Somewhat unique, the CAES project would require the approval of two main agencies: the California Energy Commission (CEC) for the development and operation of the surface facilities, and the U.S. Environmental Protection Agency (EPA) for the reservoir development and operation. The conclusion of this analysis is that the project could be permitted with minimal impacts.

2.6.7 Commercial and Economic Feasibility

In addition to determining the technical feasibility of utilizing a depleted natural gas reservoir as the storage medium for CAES, a key element of the CAES Feasibility Study was to determine the commercial and economic feasibility of the project. While studies conducted in support of the Chapter 7 provided an estimate of the costs, an RFO seeking competitive bids from third parties with an interest in developing, constructing, and operating the facility would provide a market test as to both the commercial and economic feasibility of the project. **Chapter 9, "Request for Offer (RFO) Process and Results"**, discusses the RFO, including the type of information sought, the process, a summary of the bids, and a summary of the economic evaluation.

2.6.8 Conclusions and Recommendations

Lastly, **Chapter 10, "Conclusions and Recommendations"**, outlines a few conclusions based on the research and information gathered as part of this feasibility study, and identifies recommendations for additional development work to further assess and manage the risks that come with a CAES project.

References

California ISO. 2015a. "Briefing on the Duck Curve and Current System conditions, Clyde Loutan, Market Surveillance Committee Meeting, General Session, July 15, http://www.caiso.com/Documents/Briefing_DuckCurve_CurrentSystemConditions-ISOPresentation-July2015.pdf

California ISO. 2015b. "Fast Facts: What the Duck Curves Tells Us About Managing a Green Grid," California Independent System Operator. https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

Energy and Environmental Economics. 2014. "Investigating a Higher Renewables Portfolio Standard in California." https://ethree.com/public_projects/renewables_portfolio_standard.php.

Chapter 3
Reservoir Screening and Site Identification

3.1 INTRODUCTION

The reservoir and site screening process sought to find a reservoir/site that met three objectives: 1) had suitable reservoir characteristics to allow its use as a storage medium for air, 2) matched the technical and operational requirements of the surface generation equipment, and 3) ranked as high as possible on various siting and environmental criteria. The project team, thus, aimed not simply to study the feasibility of utilizing a depleted natural gas reservoir for air storage, but to locate a reservoir/site that, if it was determined to be technically and economically feasible, would allow for the future development of the facility. Therefore, a comprehensive review of various reservoirs and sites needed to look beyond the feasibility study, and consider whether the reservoir/site had other features that would also allow for its successful development.

Siting a compressed air energy storage (CAES) project is unlike siting conventional energy projects. For example, while a new natural-gas-fired combined cycle plant can be sited at multiple locations as long as certain criteria are met (available land, reasonable proximity to electric, gas, and water interconnects, etc.), a CAES project is dependent upon and tied to the reservoir. The reservoir is key; ensuring that the reservoir has the type of properties required for a CAES project while also meeting other requirements (as will be further discussed), is critical to the project's viability. Thus, PG&E spent considerable effort in analyzing the available reservoirs and other siting factors in an effort to find a reservoir with the right mix of geological, environmental, and siting characteristics (as detailed later in this chapter) with the goal being a facility that can successfully be permitted, built, and operated while providing operational benefits and value to California's customers.

This chapter provides a step-by-step outline of the screening and siting process. It reviews the geological, historical, and environmental factors considered during evaluation. Other lesser factors considered in the process include suitability for energy conversion facilities and the complexity of ownership. A final section describes the cost evaluation model used to assist in tracking the economic pros and cons of various reservoir locations.

3.2 OVERVIEW OF SCREENING AND SITING PROCESS

PG&E developed a process that would allow for the qualitative and quantitative evaluation of numerous reservoirs and the associated siting factors with the goal of narrowing the list to five to ten sites upon which site control efforts would concentrate. Meeting the U.S. Department of Energy (DOE) objective (determining the feasibility of utilizing a depleted underground natural gas reservoir to develop a CAES facility of 300 MW with up to 10 hours of storage) drove the surface plant requirements, which, in turn, drove the reservoir requirements, including certain "must-have" criteria.

Figure 3-1 illustrates the process that PG&E employed. The funnel shape in this figure has a large opening, allowing many potential reservoirs to enter the process. Within the funnel are various screens that "filter" out reservoirs that may not meet the criteria identified. The bottom of the funnel is very thin in comparison to the opening. If the bottom of the funnel represents the core drilling and air injection phases of the project, then the goal was to sufficiently screen the various candidate reservoirs so that up to three sites proceeded to the core drilling and then one of those sites made it to the air injection test.

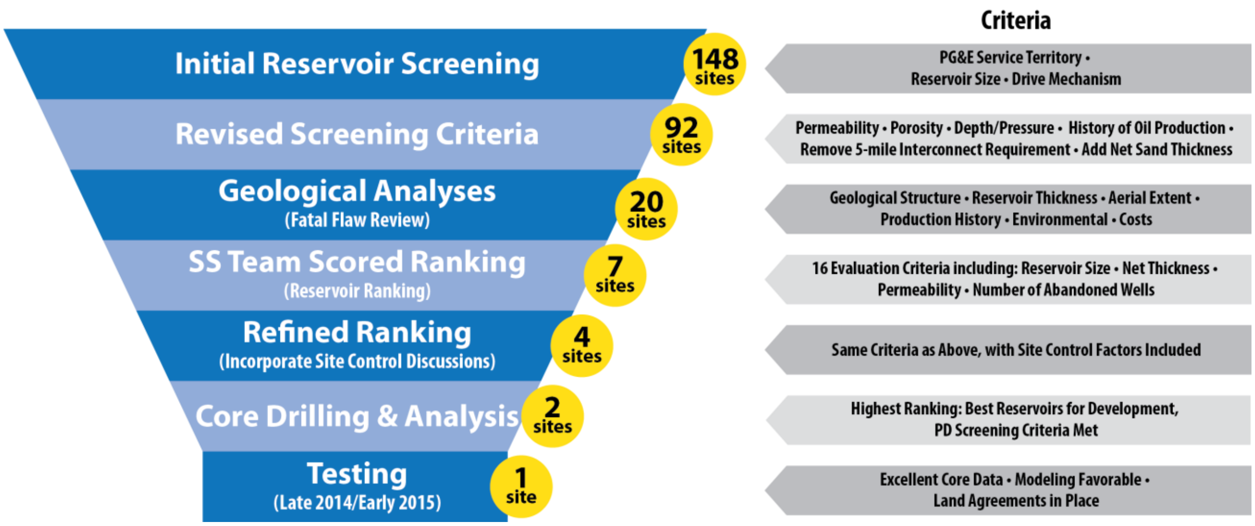


Figure 3-1 CAES reservoir screening process

3.2.1 Nine-Step Reservoir Screening Process

The reservoir screening process consisted of the following nine steps.

Step 1: Compile project team.
Recognizing that the selection of the reservoir/site would require different functional expertise, PG&E compiled a team from the following areas to participate in the reservoir screening and selection process:

- Land environmental management
- Environmental policy
- Environmental justice
- Government relations
- Gas transmission and storage
- Power plant design and engineering
- Legal
- Third-party subject-matter experts (SMEs) in the areas of geological and reservoir engineering

Step 2: Impose five-mile screen.
Utilizing a geographic information system (GIS), PG&E developed a list of gas reservoirs that were within five miles of both 230-kV electric transmission lines and gas transmission facilities in PG&E's service territory and all of Kern County. (Figure 3-2 is a map of potential gas fields in northern California.)
Based on the initial analysis, 70 reservoirs made the initial list.

Step 3A: Research public records to develop a list of reservoirs that meet initial criteria.
The California Division of Oil, Gas and Geothermal Resources (DOGGR) oversees the drilling, operation, maintenance, plugging, and abandonment of oil, natural gas, and geothermal wells (http://www.conservation.ca.gov/DOG/Pages/Index.aspx). The DOGGR publishes a set of summaries for most of the oil and gas fields in the state. The publications typically include a map, cross section, type log, and data that identify the field discovery date and the initial reservoir conditions.

For the reservoirs identified in Step 2, the project team gathered data, screened fields, and **eliminated** reservoirs based on the following criteria (see Section 3.3, "Reservoir Technical Screening," for a more detailed discussion of reservoir characteristics):

- Reservoir cumulative gas production was less than 10 billion cubic feet (Bcf).
    - Based on the project objective (300 MW, 10 hours of storage), the initial estimate was that at least a 10-Bcf field would be required.
- Field has a history of more than minor oil (condensate) or has, as evidenced by water production records, a strong water drive mechanism.
- Porosity was less than 15%.
- Permeability was less than 400 millidarcys (mD).
- Production records were available for less than 50% of the wells.
- Fields could not withstand a working pressure of at least 1,200 pounds per square inch (psi).
- Reservoirs were currently in production.

Applying the criteria to the original list of 70 reservoirs resulted in a list of 15 reservoirs. The most common reason(s) that some of the 70 fields were eliminated was either due to the field cumulative production data indicating that the field was too small or that the field had a significant number of active wells. A few fields were too shallow, and thus the pressure would be too low. Permeability data was not available for many of the fields; therefore, permeability was not a deciding factor in eliminating fields from consideration.

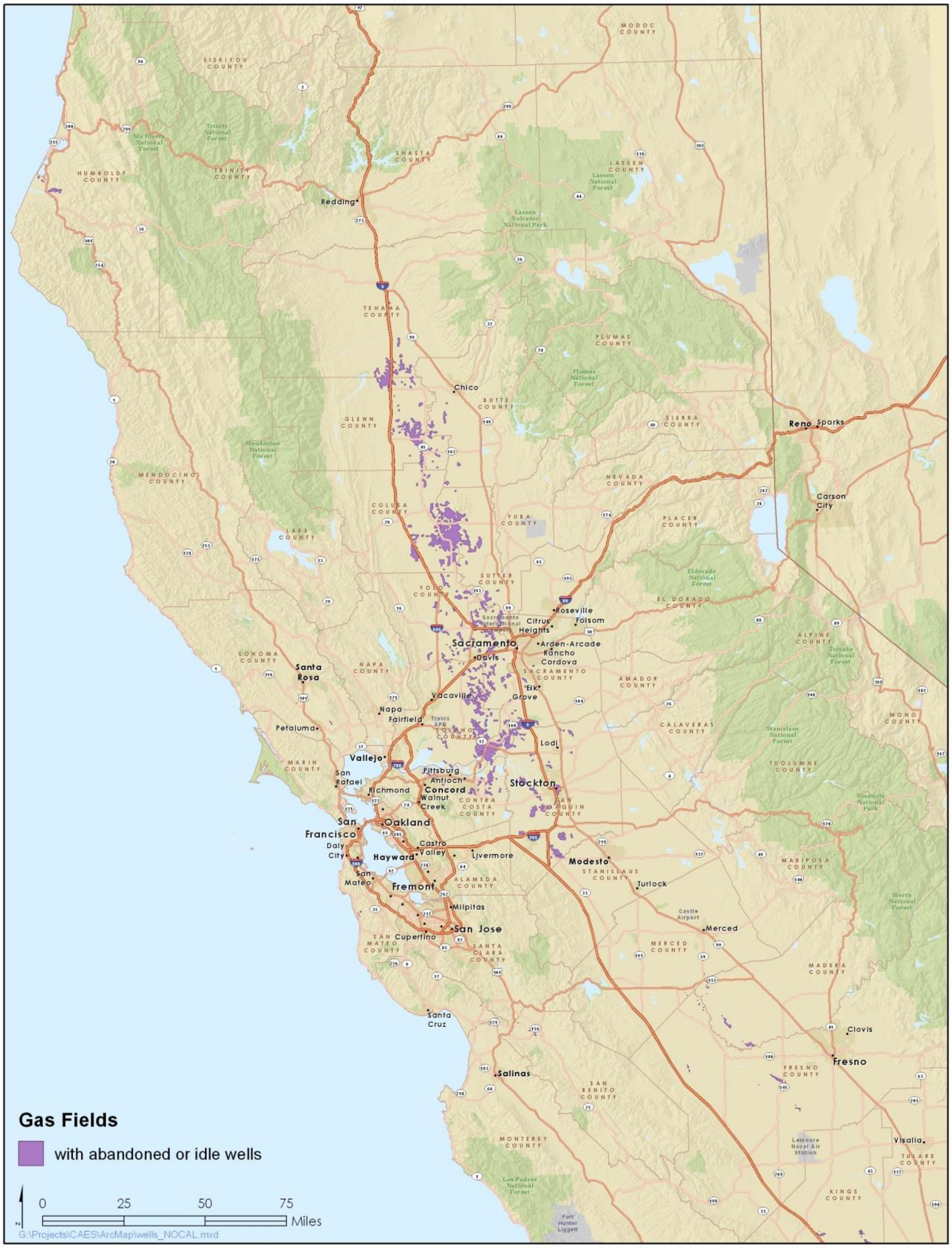


Figure 3-2 **Potential gas fields in northern California**

Step 3B: Re-visit criteria (Go/No-Go); repeat Steps 1 and 2.

During the investigation, PG&E continually re-evaluated its process and the criteria. Through those discussions, four criteria were re-visited and revised, necessitating PG&E to go back to Steps 1 and 2. Those four criteria were:

1. Recognizing the overarching importance of the reservoir and that the five-mile limit may have eliminated potential reservoirs that may have been just outside the limitation, PG&E eliminated the five-mile criteria as part of the initial screening. The interconnection cost impact, based on the distance to the point of interconnection, was accounted for in the cost model (see Section 3.6 for a discussion of the cost model).

2. In 2011, PG&E's internal market evaluation team indicated that the monetary value of storage may flatten out after the fourth consecutive hour of generation. PG&E applied an initial rule of thumb that a 300-MW x 10-hour CAES facility would utilize 1 Bcf of air per day, thus requiring a 10 Bcf reservoir. Therefore, the minimum reservoir size for a 300-MW x 4-hour storage facility was reduced to 4 Bcf.

3. Almost all reservoirs will demonstrate some form of water drive over time if the reservoir is in contact with an aquifer. A pure volumetric reservoir that does not experience some form of encroachment is very rare, because the pressure is reduced below the native equilibrium. This phenomenon may take years and may not be evident during primary production, but it can become a significant factor over the long term. The operating cycle of the CAES project is so short that water drive should not be a factor during operation. During development, one should assume that water has encroached into the reservoir as described above, and it will need to be displaced to re-create the necessary reservoir pore space.

   The reservoirs being considered had been produced for many years, and in some cases, had been abandoned or idle for several years. One must assume that the reservoir pore space is filling up with water, and in most cases the space would be completely full at the time of starting the CAES development. This effect is natural following production because, where an aquifer exists at a given pressure and the reservoir pressure is reduced due to production, the reservoir is going to achieve a new equilibrium and re-pressurize as the water encroaches. This process usually results in some amount of water production late in the life of a gas reservoir as it becomes depleted.

   Therefore, the active water drive criterion was eliminated from the screening criteria. As will be seen in Section 3.3.1, "Drive Mechanism," water drive does have some ramifications to the development of the full field air bubble.

4. In addition to the changes outlined above, a new criteria was added:
   - Net sand thickness should be 20 feet or higher. This important characteristic will improve the likelihood of achieving the very high deliverability rates required for the CAES project.

Step 4: Prioritize sites based on reservoir technical information and subject-matter expertise.
A list of approximately 92 reservoirs was created based on the addition of the new criteria. An analysis and review of the reservoir data produced the following results (see Appendix 3A, Attachment 20, Master List.xlsx):

- 18 “Yes” sites
- 36 “Maybe” sites
- 38 “No” sites

PG&E’s team of subject-matter experts then reviewed the list to determine if potential fields had been missed or mischaracterized. A priority list of 20 reservoirs was developed.

Step 5A: Conduct analysis of top sites.
Prior to moving into more detailed reservoir, environmental, and cost screening, PG&E conducted a high-level analysis of the 20 reservoirs identified in Step 4. The purpose was to discover any fatal flaws in the reservoirs that may not have been identified up to this point of the process.

This analysis (see Appendix 3A, Attachment 14, CAES High Level Review.docx) resulted in the elimination of 11 reservoirs. Further review resulted in adding three sites to the remaining sites for a total of 12 reservoirs.

Detailed geological analysis was then conducted on the top sites. This analysis was done in parallel with Step 5B, the environmental screening. Summary reports were developed of PG&E’s findings for 10 of the 12 sites, including the detailed geological studies (see Site Selection Close-out Reports, Appendix 3A, Attachments 1 through 10). The other two sites, East Island and King Island, are discussed in more detail in Chapters 5 and 6.

Step 5B: Conduct environmental, environmental justice, and development reviews.
Once the 12 sites were selected for detailed analysis, a screening then occurred to determine what potential environmental and developmental issues may arise, what the potential effects would be, how they could be addressed, and if any fatal flaws existed that would affect the sites’ potential for development should these sites be selected as part of the feasibility study.

The following environmental attributes were evaluated in no particular order (see Section 3.4 for a more detailed discussion of various environmental characteristics):

- Identification of surface landowner(s)
- Identification of location and distance of nearest inhabited structures to reservoir
- Identification of air district and permit requirements, including price of offsets
- Distance to nearest scenic highway
- Distance to wetlands
- Distance to airport or private airstrip
- Distance to flood zones
- Designation of land use, such as important federal and Williamson Act status or other conservation status
- Presence of sensitive species habitat or less than high-value Habitat Conservation Plan (HCP) habitat

Based on the evaluation, sites were assigned a Red, Amber, or Green rating. The rating was subjective and based on the expertise of the environmental team performing the evaluation.

- Red = Fatal flaw; major hurdles to develop.
- Amber = Environmental issues identified; issues may be manageable, but could lead to long, costly permitting and development effort.
- Green = Good site. Issues may have been identified but manageable.

Additionally, certain development features were also evaluated during this phase. These attributes include in no particular order (see Section 3.5, "Other Siting Factors," for a more detailed discussion of these items):

- Energy Conversion Facility (ECF) Development
- Site Control – Complexity of Ownership Structure
- Other Considerations

Step 6: Develop cost tool and provide preliminary ranking of sites based on estimated costs to develop and operate.

- In preparation for gathering more detailed, site-specific data (see Steps 5A and 5B), PG&E developed a cost model (see Section 3.6, "Cost Model," for a more detailed review of this analysis) to provide another tool for evaluating various reservoirs in relation to one another.
- The cost model evaluated specific cost factors (reservoir and surface development and related operational impacts)
    - Cost model incorporates economic factors when comparing reservoirs/sites.
    - Cost model assists with identifying various cost drivers for each site.
    - Cost model ensures that feasibility acknowledges market economics.

Steps 5A, 5B, and 6 were not static analyses. The project team continued to gather new information, re-visit old information, and update the analyses to ensure the most current data was being gathered and included in the evaluation.

Step 7: Develop list of top seven sites.

After reviewing the various sites, the project team reduced the top 12 sites to the top 7. PG&E's reservoir and storage operation subject-matter experts then ranked each reservoir based on 16 factors. Each factor was weighted based on the team's evaluation of the characteristic's importance to an air storage application.

The subject-matter experts then reviewed the known information and jointly developed a score for each factor and each reservoir. The experts applied weighting factors to the individual scores, added the totals together, and calculated a reservoir score.

Subsequent to this analysis and based on the progress of the site control discussions, PG&E continually re-evaluated sites; the project team eliminated sites and added a couple of sites. A final ranking was completed based on the information available. The results of the first and final reservoir evaluation are included in: Appendix 3A, Attachment 12, 120127 Evaluation Summary Composite.xls and Appendix 3A, Attachment 13, 120822 Evaluation Summary Composite.xls

Step 8: Conduct landowner outreach and site control negotiations; refine list as more information becomes available.
Based on the top sites identified, PG&E commenced landowner outreach and site control negotiations (see Chapter 4 for a more robust discussion of the site control efforts). As information was learned during these conversations (land restrictions, compensation requests, etc.), the information was updated in the cost model to ensure the site ranking remained current.

Step 9: Obtain site control.
PG&E's initial goal was to obtain site control at up to three sites to conduct the geological core drilling effort; obtaining the geological cores was critical to obtaining real data on the reservoir. The information would then be utilized to model the reservoir and determine which reservoir to select for an air injection test and possibly development for a full-scale CAES project.

PG&E's goal of testing up to three sites was somewhat based upon the short duration of the feasibility study and the uncertainty associated with the reservoir data. In other words, if PG&E tested only one site and the geology was different from what was understood based upon publically available data, and the site was not compatible for a CAES project, PG&E would need to re-start the site control and permitting efforts required. With the restrictions on the funding source (i.e., the DOE sponsor funds would not be available after September 30, 2015), and with the various project tasks that would need to be completed, the decision was to mitigate the project risks and test multiple sites.

3.2.2 Conclusion

Developing a structured process for evaluating different reservoirs is important; the process should be flexible enough to: 1) account for new information as it becomes available, and 2) update the screening criteria as needed. The focus needs to be on the reservoir. However, the screening process must also evaluate other factors (environmental and siting, for example) to identify fatal flaws or costly fixes that either make it very difficult for the reservoir to be developed or make it cost-prohibitive when compared to other potential storage or non-storage solutions that provide similar electricity products/services.

As identified in Chapter 5 (Core Drilling and Analysis), PG&E tested two reservoirs as a result of the reservoir screening and site control process. Both reservoirs exceeded two of the critical geological criteria established (permeability greater than 400 mD and porosity greater than 15%) and are excellent candidates for use in developing a CAES facility.

3.3 RESERVOIR TECHNICAL SCREENING

The reservoir requirements for a CAES project utilizing a depleted gas reservoir are very similar to those for a typical underground natural gas storage project. When fully developed, the CAES reservoir will be expected to deliver air to the surface at very high rates and at sufficient pressure to support the operating requirements of the power generation equipment. Likewise, the reservoir needs to be able to sustain high injection rates to allow the reservoir to be re-pressurized and improve the operating flexibility of the facility.

This section discusses the key geological and historical factors in evaluating depleted natural gas reservoirs for CAES development suitability. The geological factors include those items that are descriptive of the physical characteristics of the reservoir and surrounding formations. In other words, the geology is what nature has provided. Producing gas reservoirs in California are almost exclusively sandstone formations, as opposed to reservoirs made up of carbonate material in other gas-producing regions in the United States. The discussion of geological aspects in Section 3.3.1 focuses solely on sandstone reservoirs.

The historical aspects include the man-made intervention with the reservoir such as the drilling of exploratory and production wells, the production of gas from not only the reservoir of interest, but other formations nearby, and the plugging and abandonment of wells.

Much of the geological and historical information necessary for reservoir screening was available through the California Department of Geothermal and Geological Resources (DOGGR). DOGGR maintains a data base of geological, well, and production information, most of which is available online. Regulations require exploration and production companies to file basic well log and production information with DOGGR. Additional information, such as 3D seismic and certain well logs, may be available directly from the designated operating company records if they are willing to provide this data.

3.3.1 Geological Factors

PG&E considered 10 geological factors in determining the suitability of a site for a CAES facility: reservoir size, permeability, porosity, depth/pressure, reservoir thickness, remaining reserves, trapping mechanism, number of producing horizons, drive mechanism, and geological complexity.

Reservoir Size

Size is evaluated both for the volume of the reservoir as well as the aerial extent of the reservoir's footprint. The volumetric capacity of the reservoir is a critical component of any underground storage project. In particular, with a CAES project, a range of reservoir capacities could provide optimal performance. Reservoirs that are too small would not have enough volume to sustain withdrawal operations to meet the project objective, would require frequent recharge, and would cause large pressure swings during withdrawal. Reservoirs that are too large would require building and maintaining a much larger air bubble, increasing both development and operating costs. Ultimately, the size of the reservoir is dependent on the storage and operational needs of the system and the value that it can derive.

Aerially, the size of the reservoir is important from a development standpoint. More compact reservoirs require less infrastructure to fully develop than those spread across a broader area.

- **Measurement Techniques.** Documentation of the production history and volume of gas produced generally provides a good basis from which to estimate the ultimate reservoir volume, measured in billion cubic feet (Bcf). Determination of how much of the original reservoir volume will be usable for underground storage is dependent on whether the reservoir is determined to have experienced water drive (discussed later in Section 3.3.1, under "Drive Mechanism") or not.

Determination of the aerial footprint requires an understanding of the reservoir geology based on available information.

- **Criteria for CAES.** Analysis determined that reservoirs with an air storage capacity as small as 4 Bcf could be used. This analysis included reservoir modeling work completed early in the project (see Appendix 3A, Attachment 21, PG&E CAES Gas Screening Model, November 2011) and the evaluation by the subsurface subject-matter experts. The smaller reservoirs, however, may not be able to support the project objective of a 300-MW facility with 10 hours of storage. An upper limit of 20 Bcf was established to limit the time necessary to build an adequate air bubble, which would have an impact on the overall development cost. Regarding the aerial size, qualitatively smaller footprints in relation to their volume were considered more desirable due to less infrastructure requirements, specifically for fewer well sites and a smaller gathering system.

Permeability

Permeability is a measurement of the ability of a gas or liquid to flow through the reservoir rock, measured in millidarcys (mD). The higher the permeability, the greater the ability for the rock matrix in the reservoir to support very high flow rates to a well or system of wells within the reservoir. The permeability is typically not uniform throughout the reservoir and varies both horizontally and vertically. A sandstone formation capable of trapping and producing gas can contain many layers of rock that were deposited over time and that have very different permeability characteristics. Where porosity (discussed below) is the measurement of the space between sand grains, permeability is the measurement of how well those spaces can interact with one another and allow a fluid or gas to flow through the rock.

- **Measurement Techniques.** Unlike some other reservoir characteristics, permeability cannot be measured directly using open hole logs from previously drilled wells. Typically, core samples from the reservoir are required to be analyzed in the laboratory to determine actual vertical and horizontal permeability. A variety of tests are often run at varying conditions (i.e., confining pressure, water saturation) to obtain a better representation of the actual *in-situ* permeabilities. In the absence of actual core data, attempts are often made to qualitatively assess the permeability based on gas production data and other available information.
- **Criteria for CAES.** Early modeling work was completed to evaluate the impact of permeability and reservoir thickness together (Kh) on reservoir performance (see Appendix 3A, Attachment 15, CAES Reservoir Size Determination.pdf). Permeability ("K") is measured in mD, and reservoir thickness ("h") is measured in feet. That study evaluated varying "Kh" along with other reservoir properties (water saturation, reservoir pressure, etc.) and determined that high values of "Kh" (greater than 9,000 mD-ft) would be required to support the high deliverability requirements of a CAES project. For

example, a reservoir of 30 feet average thickness would require permeability of at least 300 mD. While it may be physically possible to achieve the necessary flow rates with lower permeability reservoirs, the increased number of wells required could prove to be cost-prohibitive.

Porosity

Porosity is the volume of void-space (which may hold fluids) divided by the total or bulk volume of the earth material, including the solid and void components. Sandstone reservoirs have the ability to contain gas and liquid in the space between the sand grains. The higher the porosity, the greater the volume capacity of the rock for holding a gas or liquid for a given volume of rock. In other words, high porosity means more space exists to hold or store gas within the rock. Generally, high porosity is associated with high permeability. The specific relationship between these two properties varies from reservoir to reservoir and has been the subject of considerable study (Nelson, 1994).

- **Measurement Techniques.** Porosity can be obtained indirectly from open hole well log interpretations or directly from core analysis. Several types of logs can be used to determine porosity, including acoustic logs (sonic) and nuclear-based logs such as neutron-density. Some of these logs may be available from the DOGGR website (DOGGR, n.d. Online Well Record, OWR) or directly from the current field operator. Calculations of porosity by these techniques can be reasonably accurate when compared to actual measurements obtained from a core sample.
- **Criteria for CAES.** Porosities as low as 15% were considered. However, porosities in excess of 30%, were deemed preferable. The general increase in permeability with higher porosity yields better reservoir performance. The aerial extent of the reservoir is smaller with high porosity rock, which provides for lower development costs (see discussion in “Reservoir Size” above).

Depth/Pressure

For reservoirs that exhibit a normal hydrostatic gradient, which is true for most reservoirs in northern California, the original pressure is dictated by depth (0.433 psi/ft of depth) (Schlumberger, n.d.). Due to this relationship, depth and reservoir pressure were evaluated as a single criteria. Less expensive wells can be drilled into the shallower reservoirs, but this advantage can be offset, at least partially, by needing more wells to achieve the same deliverability due to the lower operating pressure. Based on recently approved gas storage projects in California, storage reservoirs are often permitted to operate at higher-than-original discovery pressure (CPUC, n.d.). Reservoir pressures of up to 0.7 psi/ft of depth can be acceptable if the reservoir-bounding features (caprock, underlying aquifer, etc.) are capable of handling the higher pressure during the intended operation. Operating at higher pressures provides for a greater storage volume and higher deliverability. The potential for a reservoir to be operated at a higher operating pressure was also taken into account.

- **Measurement Techniques**. The depth to the top of the producing reservoir can be determined from the open hole logs filed with DOGGR. Original discovery pressures, as measured at the wellhead, are reported to DOGGR with the well completion data and are available from its website (DOGGR, n.d. Online Production and Injection, OPI). Wellhead pressures are also reported periodically with the production data.

- **Criteria for CAES.** Based on the early indications of operating pressure requirements for the CAES surface equipment, the acceptable range included depths as shallow as 3,000 feet, with initial pressures of approximately 1,200 psi, and as deep as 6,000 feet with pressures of over 2,500 psi.

Reservoir Thickness

Reservoir thickness is typically expressed as gross, net, or average thickness. It requires an understanding of all three to fully understand how the reservoir may perform in a storage operation. *Gross thickness* is the measurement of the reservoir sand from the highest point in the reservoir structure to the gas/water contact that typically defines the lower limit of the reservoir without regard to the quality of rock within this interval. *Net thickness* is derived from log interpretations and takes into account those layers within the sand body that are not good quality reservoir rock, such as interbedded shales or low porosity sandstones. A high net-to-gross ratio indicates that fewer vertical permeability barriers exist and the various strata within the reservoir are likely better connected. *Average thickness* is often reported, but can be somewhat misleading as to whether it is the average gross, net, or something else. A high average reservoir thickness, when compared with the gross thickness, could mean that the reservoir is rather blocky in shape, as opposed to a low average figure, which may mean a broad, flatter configuration.

- **Measurement Techniques.** Determining all three of these measurements of thickness requires an interpretation of the well logs by a qualified geologist in conjunction with an understanding of the reservoir structure. The well logs provide data at only single points within and around the reservoir. Therefore interpolation between data points and extrapolation across the entire geological structure are required to define the thicknesses at various points in the reservoir. The relative accuracy of this interpretation can be checked by comparing the reservoir volumetric calculations against the known gas production data.
- **Criteria for CAES.** Based on the modeling of “Kh” discussed under “Permeability” above and the experience of the underground storage subject-matter experts, a minimum average reservoir thickness of 20 feet was adopted. No limits were set for gross or net, although higher net percentages are more desirable due to better interaction within the reservoir (discussed above). Reservoirs thinner than 20 feet are difficult to develop for the high withdrawal capacity necessary for an underground storage project such as CAES.

Remaining Reserves

The gas reservoirs evaluated by PG&E for CAES storage were at various stages of primary depletion. Some of the reservoirs had been depleted to the extent practicable, and all wells had been plugged and abandoned. Others were in the latter stages of primary production, with some amount of commercially producible gas remaining in the reservoir. All depleted gas reservoirs have some amount of residual gas remaining. The remaining gas may be a very small percentage of the original gas volume, as in the case of a depletion drive reservoir, or relatively high for active water drive reservoirs (drive mechanisms discussed below). CAES projects require identifying the remaining native natural gas and determining the development and operational opportunities to address it. Therefore, understanding the volume and nature of that residual native gas is an important consideration.

- **Measurement Techniques.** Field/well and historical production data can be analyzed to estimate the original gas-in-place (OGIP), from which the volume of total production can be subtracted to yield an estimate of the remaining native natural gas.
- **Criteria for CAES.** The lower the volume of residual gas remaining, the better from a CAES operational standpoint. Over time, native gas will tend to mix with the injected air, and as that mixture is withdrawn, concentrations of natural gas above a limit of approximately 4% is potentially combustible (note, this requires a source of ignition). Due to the potential hazards of these higher gas concentrations within certain areas of the reservoir, various development and/or operational strategies would need to be employed to ensure the safety of the combined withdrawal stream.

Trapping Mechanism

Many types of geological trapping mechanisms are found in producing gas reservoirs, including:

- Anticlinal structures – a simple dome-type reservoir, over-laid by caprock
- Fault traps – porous formations trapped up against an impermeable fault zone
- Stratographic traps – a lateral lessening of permeability due to erosion or lithological changes forming a barrier
- Pinch-outs – a thinning of the rock formation at the edges of the reservoir
- Various combinations of these mechanisms

Some of these trapping mechanisms are more suitable for underground storage development than others (see the discussion of "Geological Complexity" below).

- **Measurement Techniques.** If sufficient geological and well control data are available, the trapping mechanism can be determined by a geological interpretation. Also helpful in this determination are regional geology and an understanding of the formation that makes up the subject reservoir and other reservoirs in the area.
- **Criteria for CAES.** Simple structures such as anticlines or fault traps are easier to develop and operate than complex structures. The more complex the reservoir becomes, the more likely it is to require additional wells (and added cost) because of the difficulty in placing them optimally in the reservoir and the more difficult the reservoir is to operate due to communication barriers within the reservoir. Complex reservoirs are also more difficult to model and predict performance once they are developed. This difficulty could lead to performance risk, which would need to be covered by additional costs/contingencies to the project.

Number of Producing Horizons

Some gas fields have multiple producing formations at differing depths that may or may not be connected in some way. If these formations are in depth proximity to each other, they may have been produced together. In this case, the gas has been commingled, and the performance of each producing horizon cannot be determined from the production records. In this case, the actual size of each reservoir cannot be easily determined. Even if the production of each zone has been isolated, it may require development of multiple zones to achieve the optimal volume requirement for a CAES project. Well design and placement are more difficult, increasing the risk that more injection/withdrawal wells will be required, which in turn increases the development cost.

- **Measurement Techniques.** Log correlation from well to well is the primary method of determining the number of discrete producing horizons. In some cases, a horizon may have been penetrated by multiple wells, and in other cases, the reservoir may be so small that it was detected with only one well. Each well can potentially penetrate multiple horizons, leading to the question about commingling of gas during production.
- **Criteria for CAES.** Ideally the reservoir has a single producing formation; if not, then having well-defined formations will lend some certainty to the reservoir size and ease of development. The complexity of interpreting the geology and having an effective CAES development increases with the number of potential storage horizons.

Drive Mechanism

During primary production, two different types of drive mechanism may be experienced and have an impact on how the reservoir will behave during storage operations. The first type of drive mechanism is depletion drive, where the pressure of the reservoir is reduced proportionately as the gas is produced. The reservoir acts as a fixed volumetric tank, and the pressure decreases to a point where it is no longer economically feasible to continue to produce the remaining gas. Depletion drive reservoirs generally have very high gas recovery ratios in the 80 to 90% range.

The second type of drive mechanism is water-drive, where the gross reservoir volume is decreased due to water entering the reservoir as the pressure is reduced as a result of gas production. The encroaching water tends to keep the reservoir pressure higher throughout the production period than a depletion drive reservoir. For very active water drive reservoirs, the abandonment pressure will be very close to the original discovery pressure. Water-drive reservoirs tend to have much lower gas recovery factors. Depending on the degree of water drive, recovery factors can be as low as 50%.

- **Measurement Techniques**. A review of the production history data can determine if the production drive mechanism is water or depletion drive. Plots of pressure vs. produced volume are relatively linear for depletion drive, with little or no water production history, versus limited pressure declines for water-drive reservoirs and typically a history of significant water production. A general assessment of the degree of water drive can be made from the production pressure profile and water production history. The pressure profiles of the production history for both types of reservoirs and an understanding of the degree of water drive are important in creating models of how the reservoir will behave in a storage mode.

- **Criteria for CAES**. Early in the site screening and selection process the PG&E team had a preference for depletion drive reservoirs. Later, however, analysis determined that, due to the very short injection/withdrawal cycles typical for a CAES facility, either type of drive mechanism would be acceptable. As a result, the screening did not set a strong preference for a particular drive mechanism, although weak water drives would be preferable to strong water drives simply due to the difference in gas recovery factor and the potential impact of that on the air storage operations. Each type of drive has its advantages and disadvantages. Depletion drive with its higher gas recovery is beneficial in dealing with residual gas mixing issues, but for CAES, this would require the entire reservoir to be filled with air back to operating pressure. This requirement would result in a larger air bubble than necessary and would increase development and operational costs. Likewise, weak water drive reservoirs typically have higher gas recovery factors than those with strong water drive, which is beneficial in dealing with residual natural gas concentration issues during withdrawal operations. Weak water drive reservoirs also have higher pressures at the start of development than depletion drive reservoirs, which will allow for the bubble to be sized for the intended operation, but water encroachment issues may arise during withdrawal operations (costs associated with the handling/disposal of the produced water). Typically the injection/withdrawal cycles would be so short for a CAES facility that water encroachment should not be an issue once the bubble is in place and stabilized.

Geological Complexity

The ability of experienced geologists to accurately map a potential CAES reservoir is dependent on the amount of data available. It may be difficult to fully understand the complexity of the reservoir geology, which can involve faults or unmapped unconformities between wells, structural or stratigraphic anomalies within the reservoir, or structural features outside the reservoir that affect its drainage and water encroachment. Geological interpretations of reservoirs tend to become more complex as more data is made available. During the initial review of the available data, if the reservoir geology appears to be complex, it is likely to create a challenge during storage development.

- **Measurement Techniques**. Prior to development for a storage operation, the available data typically consists of regional geological interpretations, well logs from a limited number of exploratory and production wells drilled in and near the gas field, and possibly some amount of proprietary seismic data. Technical papers have been written about the geology of some gas fields and regions, which may also be of assistance (DOGGR, n.d., Publications).
- **Criteria for CAES.** From a CAES development and operational standpoint, the simpler the reservoir geology is, the better. Increased complexity leads to potential development risk and increased cost, as well as potential performance issues during the operational phase. The geological interpretation of complex reservoirs may change during development as more data is made available through the drilling of wells. This new information can potentially result in changes to reservoir development plans and schedule impacts while new data is being incorporated into the design.

3.3.2 Historical Factors

Well operators in California are required to file records of their well drilling, completion, and workover operations with DOGGR. Production data, including gas and water produced volumes and wellhead pressures are also filed with DOGGR. Data for production and injection for 1977 and later are made available to the industry through the DOGGR website (DOGGR, n.d. Online Production and Injection, OPI). Pre-1977 production data is available but not accessible on the website (DOGGR, 2002). The entire database provides interested parties with the opportunity to evaluate reservoir characteristics as discussed above.

Data from numerous wells drilled in California are also available at the Well Sample Repository located at California State University, Bakersfield. Its website contains the following summary of the information available (California Well Sample Repository, n.d.):

> "On this website, you can find extensive catalogs that contain information about the thousands of oil, gas, water and core wells from California that are in our collection. There are tens of thousands of entries in our catalogs that list available core, cuttings, well logs, and paleo samples."

In addition to the geological factors discussed in Section 3.3.1, four types of historical data from prior exploratory and development work are important to consider for a CAES development, including number and type of wells in the reservoir, age of the wells, abandonment history, and availability of additional data.

Number and Type of Wells in the Reservoir

The number of wells that penetrate the reservoir of interest and their present status and condition are important factors for any kind of storage development. Previously drilled wells must be evaluated as to their condition and potential to provide a pathway for leakage from the reservoir. The amount and location of casing cement, the type of casing still in place, the rework history, and other factors need to be analyzed carefully to determine the risk that they represent to the storage operation.

- **Measurement Techniques.** A qualified drilling engineer should review available well records to determine those wells that present the greatest risk to the development and require some form of remedial mitigation. This information may include abandonment of idle non-producing wells and re-abandonment of wells representing high risk to the reservoir integrity as discussed below. This knowledge is also important when considering site control efforts for full development; depending on the ownership structure, it may require the developer to secure rights from multiple entities to gain approval to re-enter various wells in order to re-abandon them.
- **Criteria for CAES.** The greater the number of wells, the greater the potential is for problems, additional development costs, and permitting complexities. No specific criteria were established, but qualitatively, preference was given to reservoirs with fewer well penetrations.

Age of the Wells

Older wells create higher risks of failure and potential leakage from a reservoir. During the 1960s and 1970s, significant improvements were made in cementing technology and procedures to ensure good quality cement bond between the casing and the native formation; these improvements provide an excellent pressure seal for the reservoir and reduce the likelihood for leakage. Wells drilled prior to this period are suspect for providing that same quality of casing cement and represent higher risk, in the form of land rights, permitting, and costs for the storage development. The integrity of the steel casing will also degrade over time.

- **Measurement Techniques**. Well records indicate the age of the well, and the type and location of any cement used in completing the wells for production. The records also note any subsequent re-works of the well or remedial cementing, such as squeeze jobs, where cement is pumped into the annular space between the casing and the formation. In some instances, casing bond logs are available and can be evaluated for the overall quality of the casing cement in place.
- **Criteria for CAES**. This is a qualitative measure, where reservoirs with newer wells were given higher ranking than those with older wells, in particular those wells older than 1960. Pre-1960s wells need to be evaluated very carefully, with the assumption that they may need to be re-worked to ensure the necessary integrity of the storage reservoir. Wells drilled after 1960 should be evaluated as well, paying particular attention to the well records for remedial cementing, indicating problems with the primary casing cement.

Abandonment History

Many of the wells located within the reservoirs of interest have been abandoned, either at the time of drilling or after some period of production. Abandonment records were evaluated for:

- Location of the abandonment plugs
- Type and amount of cement, or other abandonment material for each plug
- Abandonment procedures
- Year the well was abandoned
- Notations of any foreign material (junk) left in the hole at the time of abandonment

The combination of these factors is critical to assess the integrity of the abandoned well and the risk that it may pose to a storage development. Wells that are suspect will likely require further evaluation during the reservoir development phase to ensure that they will not create a leakage path from the reservoir.

- **Measurement Techniques**. Well records available from DOGGR provide a good history of the abandonment data. These records need to be evaluated by a qualified drilling engineer to assess the risk associated with each abandoned well.
- **Criteria for CAES**. Newer abandonments utilizing modern techniques with no foreign material left in the well are best. Older abandonments are less desirable and may require physical evaluation, increasing the development cost. Wells with questionable

abandonments, especially those with foreign material left within the casing, can create significant remediation challenges.

Availability of Additional Data

Oftentimes data may be available for a reservoir of interest that is not available from the DOGGR website. These data may include:

- Seismic data (2D or 3D) from private brokers or owners of the data
- Geological interpretations
- Open and cased hole logs that are not required to be filed with DOGGR
- Core data and the physical core samples
- Bottomhole pressure data

These data can often be found in the well operator's files. During the evaluation phase for a potential storage reservoir, the operator may provide access to these data as long as proper confidentiality arrangements are made. The ability to review these data can be very helpful in providing a better quality evaluation of the storage capacity and operating characteristics of the reservoir.

- **Measurement Techniques.** The best way to assess the extent of the data files is to ask the current well operator for their records associated with the well of interest and to work with them to structure an arrangement where that data can be used for further reservoir evaluation.
- **Criteria for CAES.** More data provides for better understanding of the nature and capability of a potential CAES reservoir. It can eliminate surprises and/or, at a minimum, provide some indication as to the general risk and costs associated with developing the field.

3.4 RESERVOIR ENVIRONMENTAL SCREENING

3.4.1 Screening Process and Methodology

PG&E screened potential gas reservoirs for proximity to sensitive environmental areas and communities. This screening primarily utilized PG&E's extensive GIS database and was supplemented with aerial photography, independent research, and professional judgment. Initial environmental screening was conducted for the reservoir area, 0.25 mile and 0.5 mile buffers around reservoirs, within potential power plant locations, and along potential linear routes. Potential for direct and indirect effects were identified based on desktop analysis. The preliminary environmental screening identified potential high-risk environmental issues, informed permitting strategy, and in several cases determined reservoirs had insurmountable permitting issues, eliminating them from further consideration. Remaining reservoirs were considered permittable with varying degrees of avoidance or mitigation measures.

Initial Screening—Environmental Factors

Initial screening included the following environmental factors (which are described in more detail in Section 3.4.3, "Initial Screening – Environmental Factors"):

- Land Use
    - Land-use designation and zoning
    - Jurisdiction/surface and subsurface ownership
    - Legally protected areas or other land-use restrictions
    - Scenic highway/resources
    - Airport/approach patterns
    - Important Farmland and Williamson Act status
    - Water (flood zones, wetlands, and vernal pools)
    - Proximity to known hazmat sites
- Proximity to Sensitive Areas/Species
    - Biological species and habitat (Listed federal and state sensitive species, suitable habitat, critical habitat)
    - Wildlife connectivity corridors and linkages
    - Planned conservation areas
    - Existing conservation areas
- Local Community
    - Demographics (i.e., population, density, socioeconomic status)
    - Sensitive receptors (i.e., schools, hospitals, daycare facilities)
    - Nearby regulated facilities and transportation emission sources

Note that cultural resources were not included in the preliminary environmental screening process because that information was considered confidential and was only available from Information Centers on a site-specific request basis. Instead PG&E determined that cultural resource information would be collected and assessed during the detailed environmental screening of the short-listed sites described in Section 3.4.4.

Screening of Short-Listed Sites—Environmental Factors

Based on the initial locational, geotechnical, and environmental screening results, the top reservoirs were short-listed for more detailed environmental screening. The primary reasons sites were eliminated during the initial screening process for environmental reasons were that the field was too close to vernal pools or waterfowl refuges or had conservation easements on the property. Additional environmental screening factors of the short-listed reservoirs included the following (which are described in more detail below in Section 3.4.4, "Screening of Short-Listed Sites – Environmental Factors"):

- Biological species surveys, consultation with federal and state wildlife agencies, and outreach to environmental organizations
- Cultural Resources Information Center searches, field surveys, and tribal outreach
- Abandoned/historic gas wells in proximity to residential or other developed areas

Detailed biological and cultural field surveys and initiation of site control were conducted on four of the five short-listed reservoirs (see the Site Close Out reports for King Island, East Island, Cache, and Zamora for the biological and cultural field surveys conducted for each site; see Appendix 3A, Attachments 1, 10, 16, 17, 18, and 19).

3.4.2 Assumptions

The geologic reservoir site selection process was initiated concurrent with the early development of the preliminary engineering design for the power plant and well field configuration. The following assumptions were utilized for the environmental screening of geologic reservoirs for both a temporary testing site and a permanent CAES project:

- **Surface Disturbance for a Permanent Plant**. Initially, a minimum 40-acre surface area was assumed for both the permanent power plant and well field over the reservoir. As potential reservoirs/locations were identified, preliminary assessments were made and refined. It became clear that the substantially greater environmental issues associated with a power plant sited over the reservoir (in addition to landowner concerns) could become a limiting factor in permitting a project at certain reservoirs. As such, PG&E considered the separation of the wells and power plant site by up to five miles, with the well field remaining over the reservoir and connected by an air pipeline to an approximately 20-acre power plant site (as detailed in Section 3.5.1, "Energy Conversion Facility").
- **Surface Disturbance for Temporary Compression Testing Project**. The temporary compression surface disturbance associated with the Air Injection Test was assumed to include a 2-acre well pad centered over the top of the geologic formation and a temporary power supply line. The compression testing project was assumed to utilize existing access roads.
- **Proximity to Electric/Gas Interconnects.** Since the project will need to connect to existing power lines to both flow the generation into the grid and power the air compressors, and since natural gas is needed to reheat the air as it is withdrawn from the reservoir, connections to the nearest suitable lines are required. For the nominal 300-MW production, it was assumed, based on development of other power plants of approximately the same output, that a 230-kV line would be the appropriate connection. At this juncture, analysis did not determine whether the existing line had sufficient capacity available either for an additional 300 MW of generation or the compressor load; a future Generation Interconnect and System Impact Study conducted by the California Independent System Operator (CAISO) would address this issue.

  For the natural gas supply, the nearest gas transmission line was assumed to have sufficient capacity. Gas distribution feeder mains and gas distribution pipelines typically could not provide the volume and pressure required for the facility. However, if the size and operating pressure of the nearest transmission line might not support the needs of the power plant, the nearest larger-diameter transmission pipeline was also included in the assessment. Routes for both gas and electric lines, also referred to as "linears," were identified; routes were selected that minimized the distance, followed existing land-use patterns and roadways where possible, and avoided potentially sensitive land uses where practicable.

- **Noise**. Sensitive noise receptors within 0.25 mile of the temporary well drilling or compression testing site, or permanent power plant site were noted. The 0.25 mile buffer was used on the assumption that potentially substantial noise mitigation would likely be required to meet local noise ordinances or standards for sensitive receptors within this distance from the power plant.

3.4.3 Initial Screening–Environmental Factors

Land Use

The existing land uses surrounding the power plant site and along the linears were identified using Google Earth aerial images. The surface area of the majority of reservoirs evaluated was in active row crop production in rural areas. The proximity of the power plant site and linears to farm residences, agricultural buildings, and other development was noted, as described below.

Land-Use Designation and Zoning

County and city planning documents (general plans and zoning maps are available on-line for applicable cities/areas) were reviewed to determine the existing general plan designation and/or zoning classification for the power plant site as a means of gauging local development policies. Although the majority of the sites were designated and zoned for some type of agricultural activity, power production facilities were often allowed by zoning regulations in most non-residential zoning districts, subject to issuance of a land-use permit.

Jurisdiction/Surface and Subsurface Ownership

Using Google Earth and PG&E GIS resource layers, PG&E reviewed ownership to determine private versus public versus non-governmental organizations (NGOs) for both the power plant site and the gas and electric connections. Where ownership was other than private, PG&E determined the agency or jurisdiction controlling the property and noted it for further evaluation and/or outreach. The assumption was that obtaining site control from private land owners versus public agencies or NGOs would be simpler, due to the procedural and administrative limitations typically associated with the latter.

Legally Protected Areas or Other Land-Use Restrictions

Using a combination of ownership information from the county assessor files, PG&E GIS, and local planning documents, PG&E determined the conservation easements and other land-use restrictions (e.g., areas of critical environmental concern) in the vicinity of the reservoir, power plant site, and the gas and electric connections. Where protected areas were present on or near the project facilities, PG&E assessed whether those facilities would be consistent with planning efforts and planned conservation areas based on the specific resources to be protected and associated management practices. Depending on the extent of protected areas and proximity to project facilities, and types of land-use restrictions, these factors could require substantial mitigation, or in several cases, make the reservoir unsuitable for project development.

Scenic Highway/Resources

Using General Plans, PG&E searched for state-designated scenic routes and locally designated scenic routes in the vicinity of the power plant site and along the electric transmission line route as a gauge of the scenic quality or sensitivity of the area. No scenic routes were noted in the vicinity of any evaluated power plant sites or associated linears.

Airport/Flight Approach Patterns

With the power plant stacks assumed to be up to 150 feet above the ground, local plans and Google Earth aerial images were reviewed for proximity of the power plant site to airports. In addition, the 230-kV power line towers were assumed to be up to 120 feet tall, which would also potentially affect air traffic. If the Federal Aviation Regulations (FAR) Part 77 (FAR, Federal Aviation Regulations, n.d.) notification requirements were applied to the proposed power plant stacks and power line towers, power plant stacks greater than 15,200 feet and transmission structures greater than 12,200 feet from the end of a runway longer than 3,200 feet would not penetrate the imaginary surface extending from the end of a runway, and would not require submittal of Federal Aviation Administration on form 7460-1, Notice of Proposed Construction or Alteration. Where practicable, these distances were applied to the electric transmission line routing; no power plant sites would have affected a runway imaginary surface. In addition, the California Energy Commission (CEC), the lead agency for California power plant siting and licensing, has identified heat plumes from power plant stacks as potential hazards to air traffic. In the Russell City Energy Center License Amendment 1 approval (CEC, California Energy Commission, 2007), the CEC required power plant operators to implement various measures to discourage pilots from flying over the power plant, add obstruction marking to the stacks, and update various aeronautic/pilot publications marking the power plant location.

Important Farmland and Williamson Act Status

The California Department of Conservation assigns the definitions for Prime Farmland, Farmland of Statewide Importance, Unique Farmland, Farmland of Local Importance, and Urban Built-up Land. Prime Farmlands and Farmlands of Statewide Importance are considered the most valuable and are often protected by local regulations. PG&E used local planning documents (e.g., general plans, specific plans, and zoning ordinances) and PG&E GIS layers to determine the farmland status. While developing a power plant site on Prime or Statewide farmland was not considered a significant obstacle to permitting the project, mitigation for the loss of the farmland would likely be required. Farmland status is not typically a factor in siting linear facilities.

Williamson Act contracts between local governments and private landowners restrict specific parcels of land to agricultural or related open-space use. In return, landowners receive property tax assessments that are much lower than normal because they are based on farming and open-space uses as opposed to full market value. Power plants are typically not considered compatible uses, but gas pipelines and electric transmission lines are considered compatible uses. Contract cancellation is possible through the local land-use permitting process and has occurred regularly throughout California in permitting renewable power development. However, the landowner is required to pay a cancellation fee equal to 12.5% of the cancellation valuation (unrestricted fair market value) of the property.

Water (Flood Zones, Wetlands, and Vernal Pools)

Using Federal Emergency Management Agency (FEMA) maps, local planning documents, GIS, and Google Earth aerial photography, PG&E determined the presence of flood zones, wetlands, and vernal pools. The screening process avoided wetlands and vernal pools where practicable. Where these sites were not practicable to avoid, potentially significant impacts could render the reservoir unsuitable for project development. Location of the power plant site within the 100-year flood zone was noted and, depending on flood water depth, could be addressed by engineering solutions. PG&E reviewed Google Earth images of the area surrounding the power plant site to determine the proximity to wastewater treatment facilities, as a preferred source of power plant cooling water.

Proximity to Known Hazmat Sites

The State of California, local agencies, and developers use the Hazardous Waste and Substances Sites (Cortese) List to comply with the California Environmental Quality Act (CEQA) requirements for providing information about the location of hazardous materials release sites. The California Environmental Protection Agency (EPA) provides annual updates to the Cortese List. The California Department of Toxic Substance Control (DTSC) is responsible for a portion of the information contained in the Cortese List, and other state and local agencies also contribute data. PG&E reviewed DTSC's EnviroStor database, which is found on the Cortese List website, for the proximity of any known sites in the vicinity of the power plant site. Project features were not affected by any hazmat sites.

Proximity to Sensitive Areas/Species

To minimize impacts to habitat and species, a preference was given to degraded and or previously disturbed areas, such as low-value agricultural lands, for siting the project. However, the availability of disturbed and degraded lands was not always found in proximity to the potential gas reservoirs. The surface area of some of the reservoirs located in rural areas overlapped with known habitat and/or conservation areas to varying extents. For this reason, sites were screened for potential presence of species and wildlife habitat.

Using Google Earth, aerial images, and PG&E GIS data, PG&E identified habitat, species, and existing and planned conservation areas on the surface extent of the geologic reservoir, the land surrounding the power plant site, and along the gas and electric connections. . Potential project issues with these land uses are the noise and human activity associated with the initial well drilling and periodic well maintenance, and power plant construction and operations. Proximity of the reservoir and power plant site to large areas of conservation lands and species habitat was considered a major constraint to development, primarily due to increased complexity in permitting and potential stakeholder concerns in those areas and the need for the wells to be located directly above the reservoir. To identify the least-conflict sites for development, early in the screening process, PG&E consulted state and federal wildlife agencies—the California Department of Fish and Wildlife (CDFW) and the U.S. Fish and Wildlife Service (USFWS)—and environmental stakeholders (such as members of the Central Valley Joint Venture*, a coalition of agencies and private conservation organizations) to obtain initial feedback on potential project sites.

Biological Species and Habitat (Listed Federal and State Sensitive Species, Suitable Habitat, Critical Habitat)

Using PG&E's GIS system, which includes all publically available resource information, as well as other pertinent resources, PG&E determined the potential for the project area to support habitat for rare species and sensitive habitats (e.g., special-status species, waters of the United States, and other sensitive biological resources). The evaluation considered special-status species listed in the U.S. Fish and Wildlife (USFWS) species list and those reported in the California Natural Diversity Database (CNDDB) to occur within a 5-mile radius of the project area (e.g., giant garter snake and Swainson's hawk). Additionally, screening also considered special-status species not specifically included in the USFWS species list or CNDDB records due to their known geographic range and/or the presence of potential habitat (e.g., white-tailed kite, loggerhead shrike). The key issues with most of these species are the potential for direct take during project construction, as well as the loss of habitat from the permanent facilities. PG&E presented federal and state wildlife agencies and environmental stakeholders with candidate sites during initial screening and provided input regarding environmental considerations and project permitting for potential locations.

Wildlife Connectivity Corridors and Linkages

A network of connected wild lands is essential to the continued support of California's diverse natural communities in the face of human development and climate change. In 2010, the California Department of Fish and Wildlife and the California Department of Transportation (Caltrans) produced a statewide assessment of essential habitat connectivity (California Department of Fish and Wildlife and California Department of Transportation, 2010), with a goal to identify large remaining blocks of intact habitat or natural landscape and model linkages between them that need to be maintained, particularly as corridors for wildlife. PG&E screened each potential reservoir on the Essential Connectivity Map (see Figure 3-3) for proximity to natural habitat blocks that support native biodiversity (Natural Landscape Blocks) and areas essential for ecological connectivity between them (Essential Connectivity Areas). While proximity to these areas was not considered the sole basis for a reservoir to be determined unsuitable for project development, this screen indicated other possible constraints to development, such as presence of protected lands or sensitive species.

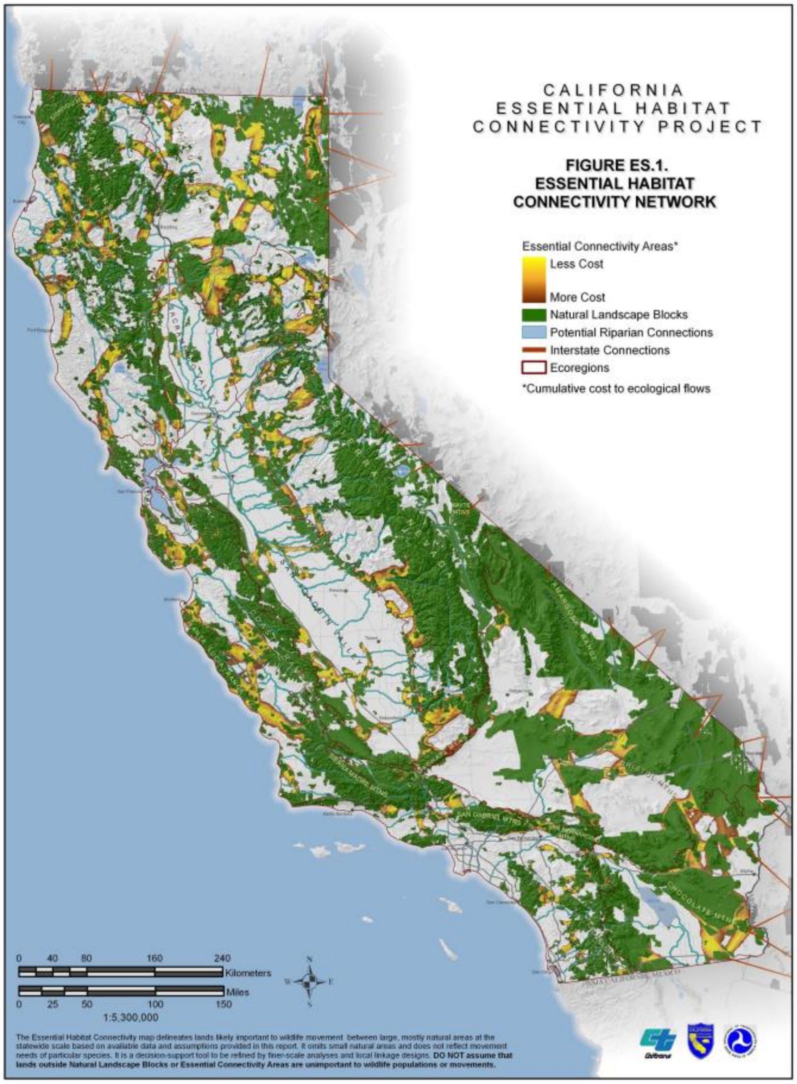


Figure 3-3 California Essential Habitat Connectivity Project—Essential Connectivity Map

Planned Conservation Areas

PG&E evaluated reservoirs for consistency with local and state planned conservation areas, such as restoration opportunity areas for the Bay Delta Conservation Plan (BDCP) (Bay Delta Conservation Plan, n.d.), a comprehensive conservation strategy aimed at protecting dozens of species of fish and wildlife, while permitting the operation of two of California's biggest water delivery projects. Compatibility with planned conservation areas helped gauge the level of support from the environmental community and wildlife agencies for the CAES project. For example, the BDCP proposes restoration of 65,000 acres of freshwater and brackish tidal habitat as primary mitigation for a state water transfer project. Screening evaluated reservoirs for compatibility with BDCP planned restoration actions, including the establishment of "Restoration Opportunity Areas" (ROAs) within the Delta area to guide siting for habitat restoration projects.

While proximity to these areas was not the sole basis for a reservoir to be considered unsuitable, this screen indicated other possible constraints to development, such as project design and agency and stakeholder concerns with development of an energy facility in an area targeted for conservation. For the few reservoirs located within BDCP ROAs, project development would need to include added design features to withstand potential inundation (or separation of the power plant from the well field). These types of project accommodations (elevated structures for example) would add costs to the project and could meet with permitting resistance and/or require mitigation measures that affect the project cost and/or operation.

Existing Conservation Areas

PG&E evaluated reservoirs for compatibility with existing and/or designated state and local conservation areas, conservation land owned by NGOs, Audubon Important Bird Areas, and high-value Habitat Conservation Plan areas (HCP) (such as the Kern County Valley Floor HCP, see Figure 3-4) (Kern County, 2006). HCPs allow landowners to receive a federal permit, known as an incidental take permit, in exchange for providing protections for endangered and threatened species. Compatibility with existing conservation areas helped gauge the level of support from agencies; the environmental community identified potential species concerns, and permitting challenges early in the siting process. For example, Audubon California has identified and mapped 145 Important Bird Areas (Audubon California, n.d.) that provide more than 10 million acres of essential habitat for breeding, wintering, and migrating birds. While proximity to these areas was not the sole basis for a reservoir to be considered unsuitable, this screen indicated other possible constraints to development, such as presence of nesting birds, sensitive species, and stakeholder concerns with the project.

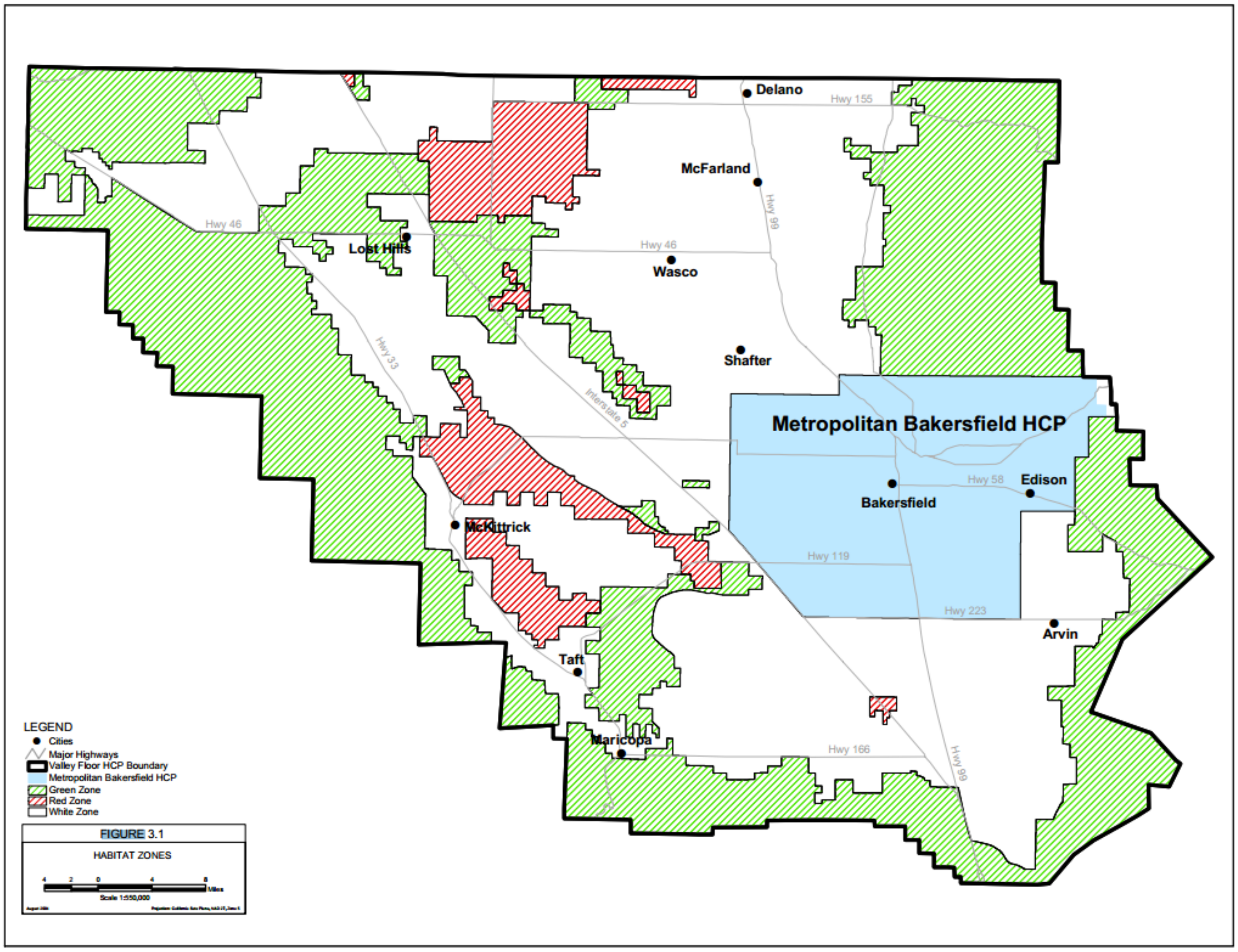


Figure 3-4 Kern County Valley Floor Habitat Conservation Plan Zones

Local Community

The local community screening included an evaluation of community demographics, sensitive receptors, and existing emission sources in relation to the gas reservoirs and the anticipated power plant location (if separated). Environmental Justice concerns (PG&E, n.d.) were identified through the assessment, and include the following.

Demographics (i.e., Population, Density, Socioeconomic Status)

PG&E identified residential land uses (and communities) using Google Earth aerial images within 0.25 mile and 0.5 mile buffers around gas reservoirs, within and surrounding the power plant site, and along the gas and electric connections. In addition, the screening used census data to identify the socioeconomic status of the local community. Reservoir locations under or within proximity to densely populated areas were considered unsuitable for project development. In sparsely populated, active agricultural and rural areas, the screening noted gas reservoir, power plant site, and gas and electric equipment proximity to residences and other development, and safety concerns were communicated to the project team.

Sensitive Receptors

Sensitive receptors include, but are not limited to, hospitals, schools, daycare facilities, elderly housing, and convalescent facilities (U.S. EPA, n.d.). In these areas, the occupants may be more susceptible to the adverse effects of exposure to toxic chemicals, pesticides, and other pollutants. Using GIS data, PG&E inventoried potential sensitive receptors in proximity to the power plant site; these receptors were mostly observed near reservoirs located under densely populated areas. The screening also identified linear routes for electric and gas infrastructure that avoided potentially sensitive receptors by 0.25 mile where practicable, with 0.25 mile the assumed proxy for appropriate setback from facilities associated with the project.

Nearby Regulated Facilities and Transportation Emission Sources

The screening inventoried emission sources (such as those from regulated facilities and transportation corridors) using data from the United States Environmental Protection Agency's Toxic Release Inventory for stationary sources. No notable observations were made in proximity to these facilities.

3.4.4 Screening of Short-Listed Sites—Environmental Factors

Biological Species Surveys, Consultation with Federal and State Wildlife Agencies, and Outreach to Environmental Organizations

PG&E completed field reconnaissance surveys and biological constraint reports for the four short-listed sites and shared this information with federal and state wildlife agencies. In addition, PG&E discussed avoidance and minimization measures (e.g., biological monitors, exclusion fencing, seasonal windows, etc.) for these sites in detail with federal and state wildlife agencies. PG&E also consulted environmental stakeholders to provide detailed input on environmental constraints and permitting approach for the short-listed sites.

Cultural and Historical Resource Information

Through the California State Historic Preservation Office, PG&E obtained cultural and historical resource information center searches, conducted field surveys, and initiated tribal outreach.

Abandoned/Historic Gas Production Wells in Proximity to Residential or Other Developed Areas

For the short-listed sites, PG&E used GIS data to inventory existing abandoned and capped wells in proximity to residences and sensitive receptors; safety concerns were communicated to the project team.

3.5 OTHER SITING FACTORS

Not all of the factors considered were neatly captured in the review of the reservoir and/or environmental factors. The following factors/issues were also considered as part of the screening process.

3.5.1 Energy Conversion Facilities (ECF)

Loosely defined, these facilities consist of all the various above-ground plant, equipment, and systems required to:

- Compress air to the required maximum reservoir pressure (compressor plant) and
- Convert the stored air into electric power at the required interconnection conditions (generation plant)

Various Energy Conversion Facility (ECF) configurations were considered, including:

- Co-locating the compressor plant and well pad facilities above or adjacent to the reservoir
- Locating all surface facilities at/adjacent to the reservoir
- Locating all ECF facilities at a separate location from the reservoir interconnected by a large--diameter air pipe; this configuration became known as the "Separation Option" (see Section 3.5.2).

3.5.2 Separation of ECF from Reservoir

At the start of the screening process, PG&E assumed that the ECF needed to be co-located with other well-field facilities above or adjacent to the reservoir. During the ownership and environmental screening process, PG&E found several reservoirs located under or adjacent to areas that were environmentally sensitive, in known flood zones, in Environmental Justice (EJ)-sensitive areas, in areas with incompatible land use, or in locales associated with landowner concerns about the use of the surface property. Subsequently PG&E conducted analysis to determine the technical and economic issues associated with bi-furcating the ECF from the reservoir. This analysis considered the following factors:

1. **Pressure Drop.** Associated with the longer air pipe runs to/from the reservoir and the corresponding increase in compressor parasitic load and decrease in generation output.
2. **Additional Capital Costs.** Associated with larger compressors, longer air pipe runs, larger pipe diameter, etc.
3. **Cost Impacts Related to Linears.** Various, primarily gas supply and "gen-tie" (generation interconnection).

The Cost Model (CM) was adapted for use in evaluating the various costs and benefits associated with various separation scenarios. The CM indicated that separation of the ECF from the reservoir can be technically and economically feasible for distances up to 3 miles or greater, depending on the potential to shorten the linear interconnections relative to the length of the air pipe. Sites that may have been eliminated (for example, due to ownership reluctance to allow an ECF on their property or other siting/development issues), were, therefore, rendered feasible. In some cases, project costs improved. For example, the higher costs associated with acquiring rights for the air pipeline and the pipeline costs itself were offset by locating the ECF closer to the electric and natural gas interconnects (thus reducing those costs). Another example was associated with floodplain issues. Some reservoirs were located slightly below sea level; being able to site ECF out of the flood zone avoided the costly civil/platform work that may have been required in a flood zone.

Figure 3-10, later in this chapter, provides a visual for looking at the benefit of separation. The figure indicates two values for King Island based on information/data known at the time of the analysis. “King Island” with a value of $12M is an estimate of the total lifecycle costs above the Base Case facility based upon the ECF being located on the reservoir. “King Island Alt” represents a scenario whereby the ECF is separated from the reservoir; as the figure indicates, the lifecycle costs improved by approximately $16M by bifurcating the ECF from the reservoir.

After consideration of the technical, economic, legal, regulatory, and other factors, PG&E determined separation of the ECF from the reservoir to be feasible and selected it as the Base Case development scenario, along with ownership of all of the associated rights and infrastructure by a common developer.

3.5.3 Site Control—Complexity of Ownership

Complexity of ownership is a combination of quantitative (cost) and qualitative (likelihood of success) factors. In many cases, the mineral rights have been severed from the surface ownership. Furthermore, the ownership of the mineral rights themselves have been severed, resulting in multiple owners of those rights (see Chapter 4, “Site Control”).

The complexity of the ownership structure manifested itself in various ways and was qualitatively and quantitatively factored into the evaluation through the following:

- **Site Control Agreement.** Type of agreement required, the owner compensation requests, and the number of owners. Given the time and effort required to negotiate each agreement, and in many cases the need to customize the agreement to address specific issues, the latter turned out to be one of the most crucial factors.
- **Alternatives.** The more flexibility to site facilities and/or conduct the various tests, the more attractive a site could be.
- **Economic and Commercial.** Actual or indicated terms from initial owner contacts were obviously important. Not surprisingly, in cases where multiple rights had to be obtained from multiple owners, the owners all would have different perspectives of the value of their rights as well as specific commercial and/or non-commercial terms that were important to them.
- **Actual Success**. In some cases, a site was eliminated based on negotiation progress/status with key owners, while other sites were able to achieve a high degree of progress with all required owners

Although more qualitative than most of the screening criteria, ownership complexity was an important screening consideration due to the direct correlation with success probability. In terms of acquisition, success ultimately would require site control of all required rights within the available timeframe. The ranking of a particular site could be improved with demonstrated progress in obtaining actual site control from various owners or by determination that the ownership structure was relatively simple (i.e., only a few relevant property owners).

3.5.4 Other Considerations

Cooling Water Supply

Due to preferences for reclaimed water conveyed in past CEC siting cases, siting opportunities where ECFs could be located near existing Waste Water Treatment (WWT) plants were favored. However, this was not a definitive screening criterion due to unknown engineering restrictions.

DOGGR Status

In some cases, DOGGR "Field Rules" were still in force for a particular reservoir. The Field Rules established by the DOGGR only apply to Class II wells (i.e., oil and gas production and injection wells). DOGGR defines Field Rules as follows on its website:

> "Pursuant to California Code of Regulations (CCR) Title 14, Division 2, Chapter 4, Section 1722 (k), the State Oil and Gas Supervisor may establish Field Rules for any oil and gas pool or zone in a field when sufficient geologic and engineering data is available from previous drilling operations. Field Rules supplement more broadly applicable statutory and regulatory requirements. Each Field Rule is specific to a field, and in many cases, specific to Areas and Zones or Pools within a field.
>
> The Division has established Field Rules for those fields where geologic and engineering information is available to accurately describe subsurface conditions. These Field Rules identify downhole conditions and well construction information that oil and gas operators should consider when drilling and completing onshore oil and gas wells."

This status afforded the significant advantage of having the wells and related facilities effectively having completed a CEQA review. This status is helpful for all drilling activities (core drilling, air testing, and any permanent field development).

Air District

The applicable air district corresponding to the project site was identified and qualitatively assessed to determine potential fatal flaws (i.e., availability of emission reduction credits, difficult permitting requirements, etc.). No fatal flaws were identified for the short-listed projects.

Flood Zones

Being located in a flood zone was generally not considered a risk during the testing phase. Its impacts to cost are more fully described in Section 3.6.

3.6 COST MODEL

The project team prepared a cost evaluation model ("Cost Model") to assist in tracking the "economic" pros and cons of various reservoir locations. The model evolved not with the intent of evaluating the absolute, cumulative cost impact of each site attribute; instead it was important to identify for each candidate site the Net Present Value (NPV) of the total lifecycle costs over the 30-year project life and then compare it to a Base Case site. Some of the factors would affect costs only during development; others would affect operation costs. For example:

- **Existing Wells.** Looked at the age of existing wells to determine potential costs associated with being required, as a result of permitting, to re-plug and abandon the wells.
- **Reservoir Pressure.** Looked at the reservoir's pressure and its potential impacts on the amount of compression power. This factor affected both the Capital Expenditure ("CAPEX") and Operational Expenditure ("OPEX") required.
- **Number of Wells Required.** Looked at, based on the then current information known regarding reservoir geology, the number of wells that would be required, which affects both the CAPEX and OPEX of the facility.

Each candidate site was assessed against each other by comparing it to a "base site." The base site was a hypothetical site based on a perceived desirable location from the standpoint of reservoir well field development, reservoir size, pressure, depth, permeability, ownership issues, environmental issues, proximity to gen-tie, and other factors deemed to be drivers of lifecycle costs.

The sites were then ranked against one another; as new information became available, the Cost Model was updated. The rankings and associated analysis provided the team with a quantitative guide during the reservoir screening process. Based on the information known at the time, the Cost Model provided insight into the cost competitiveness of each site relative to each other and relative to other market technologies.

3.6.1 Base Case Development

The project team established a CAES design or Base Case project criteria that would yield an overall well field and power block cost, and development structure that would allow for a forecasted, competitive installed cost ($/kW). A competitive cost per installed kW was determined by averaging recent California Energy Commission reported survey costs for technologies that would compete in the same markets as the CAES facility—namely, natural-gas-burning combustion turbine and combined-cycle facilities that compete in the capacity, energy, and ancillary services market. This pricing ranges from $1,400 to $1,700/kW, with heat rates ranging from 7,000 to 11,000 Btu/kWh. The Base Case scenario utilizes $1,550/kW to target CAES facility cost elements. Each site was then evaluated for each attribute to arrive at +/- cost difference at the individual attribute level; costs were then aggregated at the facility level, and sites were ranked in order of lowest to highest cost when compared to the Base Case.

The elements of the Base Case design and associated development and operations cost structure include:

- Well field and gathering system
- Power generation block
- Compression block
- Interconnects (linears) to the Energy Conversion Facility (ECF)
    - Electric
    - Natural Gas
    - Water

Table 3-1 illustrates the individual attributes and values of the Base Case site by which all sites would be compared. Table 3-2 identifies the individual attributes but only as they apply to the reservoir itself (see Section 3.3 for a more detailed description of the attributes presented in Table 3-2). Table 3-1 identifies the distinct attributes being evaluated (geologic development impacts and power facility impacts). For instance, Reservoir Pressure in Table 3-1 speaks to two specific power facility lifecycle operational impacts (i.e., impact on Plant Capacity as well as Compression Power required). Table 3-2 identifies the key geological/reservoir attributes analyzed; these attributes are factored into both the CAPEX and OPEX calculations.

Table 3-1 Base Case Evaluation Attributes and Values

CAPEX	1550 $/kW
OPEX	35 $/kW-yr
Pressure (Capacity Impact)	1600 psig
Pressure (Compression Impact)	1600 psig
Separation	0 miles
Depth (feet of drilling)	4000 feet
Permeability (mD)	400
Size (Bcf)	10
Total Land Purchase $ (including all rights)	60,000,000
Distance to Electric Interconnect – Gen-Tie	1 mile
Distance to Gas Interconnect	1 mile
Pressure at Gas Interconnect	500 psig
# of Wells Required	35
# of Wells Required (Porosity)	35
# of Wells Required (Thickness)	35
TSF Complexity - Temp Power	$400,000
Environmental Mitigation Costs	$8,000,000
Network Upgrade Costs	$3,000,000
Site Development Impact on Schedule	0 days
Floodplain Mitigation	$3,000,000

Table 3-2 Reservoir Ranking Characteristic Attributes

OGIP Size (Bcf)
Net Thickness
Reservoir Size (Acres)
Original Pressure (psig)/Depth
Drive Mechanism
Caprock Thickness (ft)
# of Traps for Storage Development
Permeability (mD)
Porosity
Remaining reserves (Bcf)
Water Saturation
Abandoned Wells
Producing/Idle Wells
Abandoned Wells w/ Issues
Age of Existing Wells (Years)
Trapping Mechanism

3.6.2 Individual Site Development

Based on known information and the site-specific characteristics, the PG&E team then began to assign values to various attributes identified in Tables 3-1 and 3-2. The Cost Model would then utilize those values and convert them to site costs. For example, if based on the known data, a reservoir was forecast to require 25 wells, the CAPEX and OPEX of those wells would be calculated and factored into the overall costs for the site. In this example, the CAPEX and OPEX of the 25 wells would be lower than that calculated in the Base Case (which assumed 35 wells). Conversely, if the site required a 3-mile electric interconnect, that attribute's cost would be higher than the Base Case (3 miles vs. 1-mile Base Case estimate).

The comparative graphs in Figures 3-5 and 3-6 offer a simple way to compare drivers of the attractiveness of each site against other sites. At a glance, users can identify trends and elements that are either common to the population of sites or unique to one individual site. The figures also provide valuable insight into the site-specific cost drivers that could be utilized in negotiations to gain more favorable access, siting, etc. that could possibly help increase the competitiveness of a specific site.

3.6.3 Attribute Evaluation–Select Examples

The following examples illustrate various attributes, how they were analyzed, and their importance to the Cost Model evaluation.

Facility Bifurcation

One interesting example has to do with the reservoir being located in a floodplain. The original Base Case scenario was that the ECF would be located on the reservoir surface property and, therefore, no bifurcation of the facility would have been necessary. However, as previously discussed, bifurcation became a necessity for many reasons. One such reason was to site the ECF out of the floodplain to avoid costly civil and potential platform/build-up requirements.

Figures 3-5 and 3-6 illustrate these drivers and the impact that the separated ECF site had on mitigating costs associated with these items. The clearest example is the floodplain attribute.

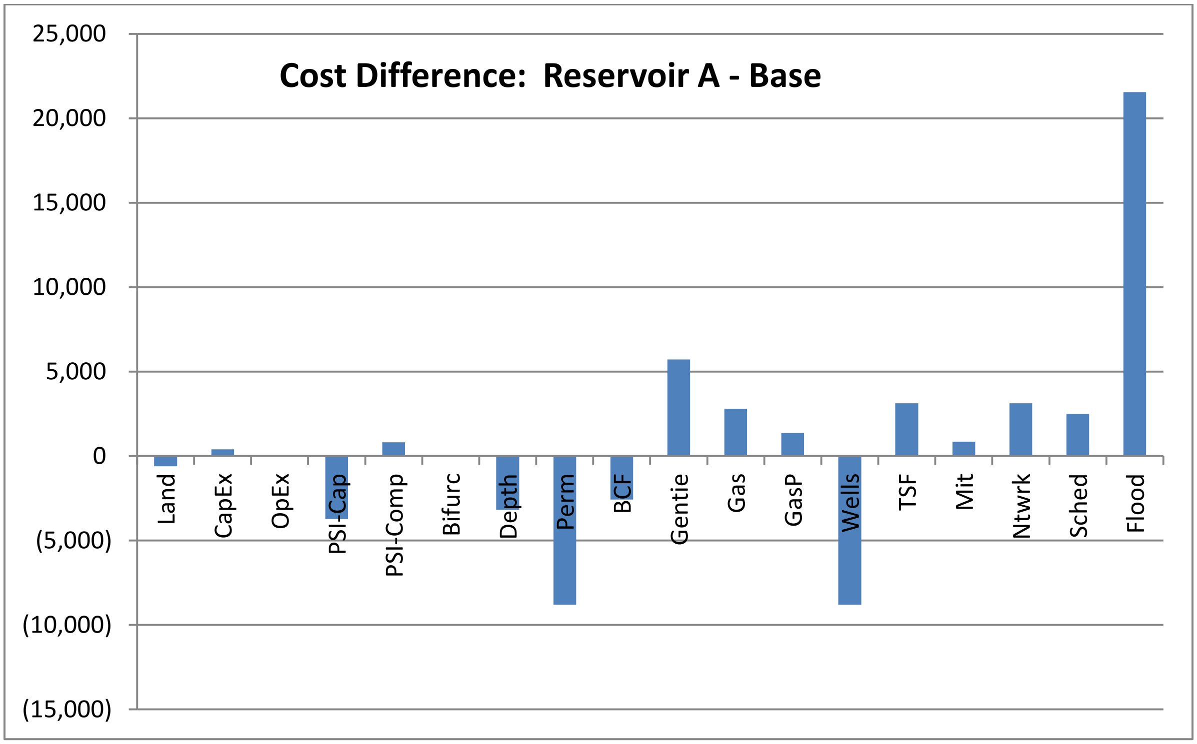


Figure 3-5 Facility A Cost Components, Relative to Base Case (Co-Located ECF and Wells), $000

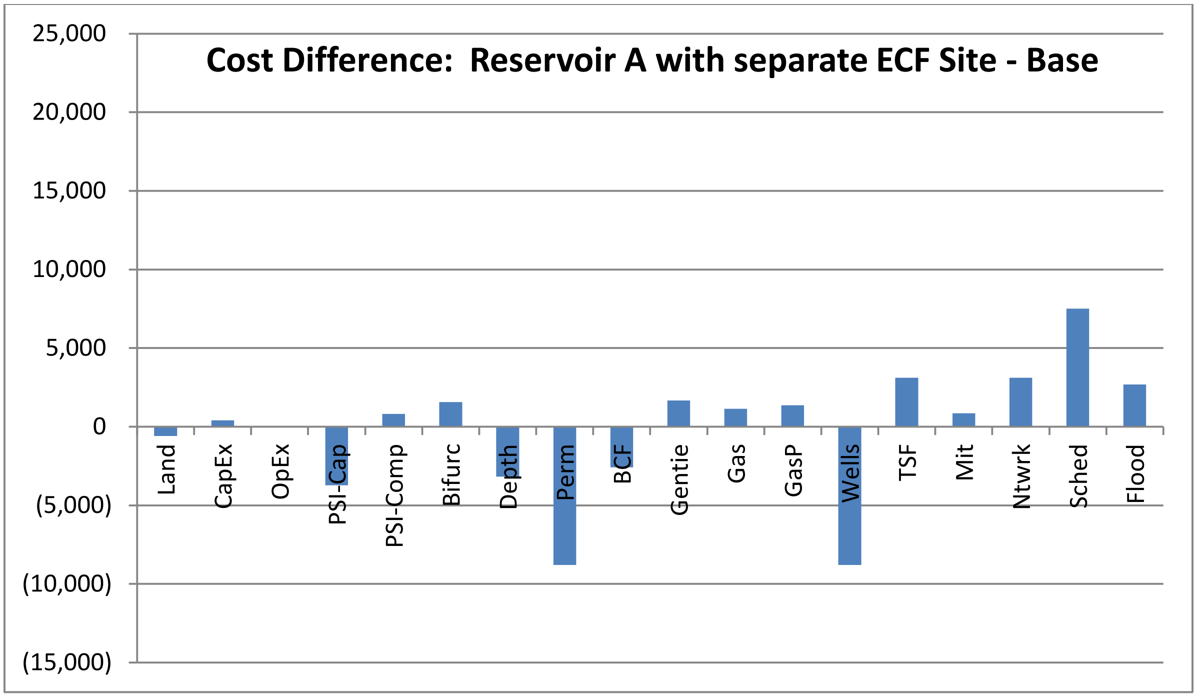


Figure 3-6 Facility A Cost Components, Relative to Base Case (Facility Bifurcated), $000

As can be seen in Figure 3-5, Reservoir A clearly has a floodplain cost element. In Table 3-1, the Base Case assumes that flood mitigation will have a $3M cost impact. Figure 3-5 shows that Facilty Location A would incur flood mitigation costs of approximately $22M greater than the Base Case amount.

Figure 3-6 also represents Reservoir A, but with the ECF now separated from the reservoir. As can be seen, the flood mitigation costs are now on par with what was assumed in the Base Case. Additionally, the separation had an added benefit of reducing the linear's cost (Gen-Tie/Electric Interconnect and Natural Gas Interconnects). By separating the ECF from the reservoir, the ECF would be physically closer to the Gen-Tie and Natural Gas interconnect points, and out of the floodplain, providing benefits to the project site.

In analyzing the cost and operational impacts of ECF separation, the Cost Model factored in the addition of a high-pressure air-line to be installed of sufficient size to minimize pressure drop—complete with appurtenances such as cathodic protection, impurity removal, valving, etc. The costs for this line were determined using installed-cost-per-foot values for the required line size and distance while allowing for a reasonable pressure drop. It was also assumed the pipe would be buried and appropriate easements would be obtained to allow for construction and maintenance activities.

Forecasting the Number of Wells

Permeability is a measure of the capability of the reservoir to deliver the required air for the CAES plant. It's a critical component in determining the number of wells required and whether or not the wells need to be vertical or directional. Because some sites were being desktop-evaluated, permeability was not always known, so various other elements such as porosity and thickness (which speak to deliverability) were utilized to estimate permeability when it was unknown.

The number of wells required for a given reservoir can be estimated from its porosity and thickness. Estimation was not preferred (which was a reason for taking core samples, as outlined in Chapter 6). However, absent any other information on the geologic structure, a method was needed to arrive at an estimate of a major cost driver. An example of this is illustrated in Figure 3-7.

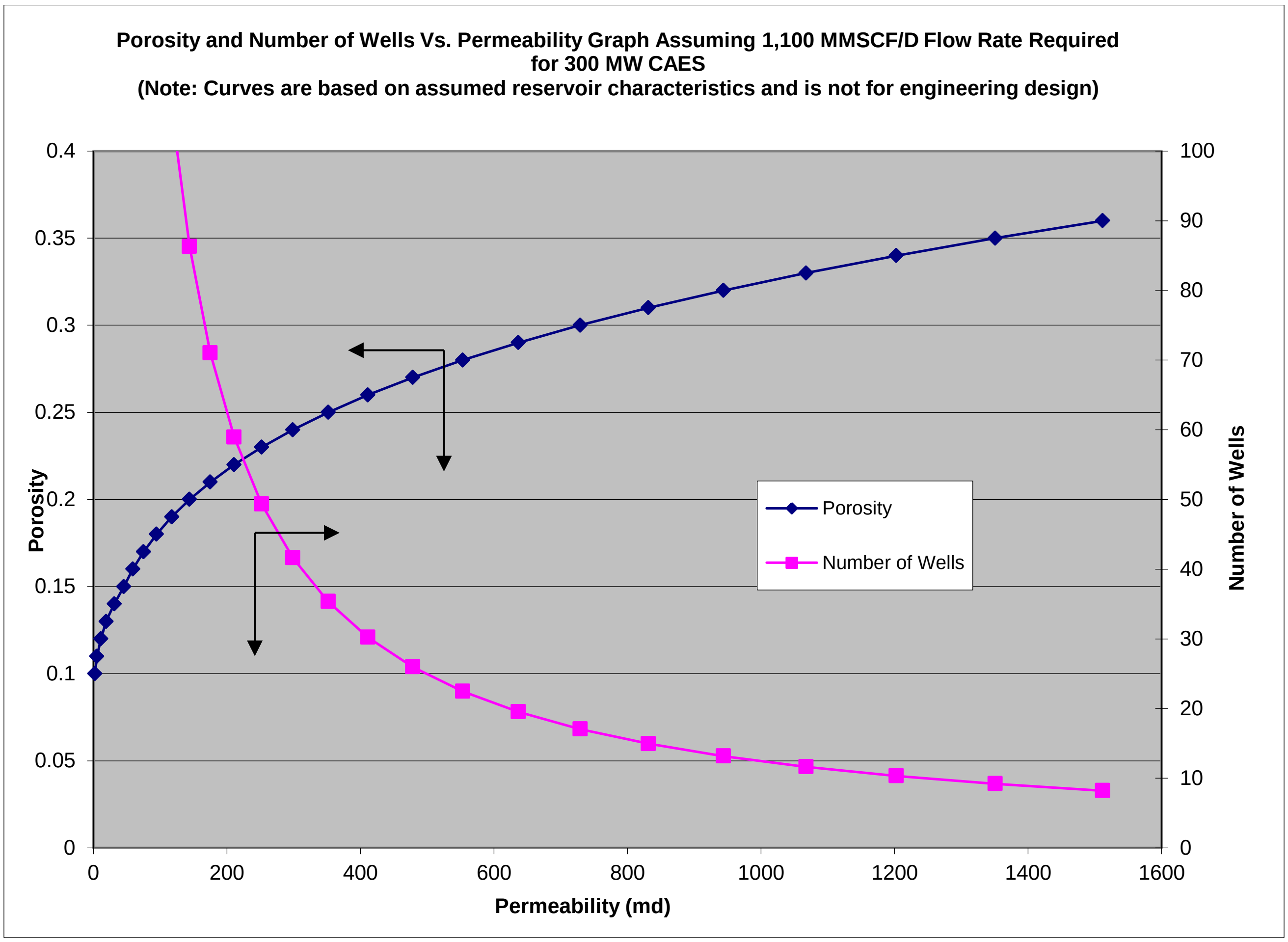


Figure 3-7 Number of Wells versus Porosity and Permeability

This curve was based on various assumptions and holding constant certain geologic properties, which speak to deliverability (such as formation thickness and flowrate). An estimated permeability was calculated by utilizing this curve within the model, once the porosity was input. This information was then used to estimate the number of wells for the CAPEX and OPEX cost calculations.

Impacts of Reservoir Pressure

The greater the discovery pressure of a reservoir, the greater will be the allowable operating pressure of a CAES plant reservoir. The greater the operating pressure of the reservoir, the greater will be the charge energy to inject air into the reservoir, and the greater will be the potential discharge energy when withdrawing air from the reservoir. These effects can be seen in a general sense in Figures 3-8 and 3-9 below.

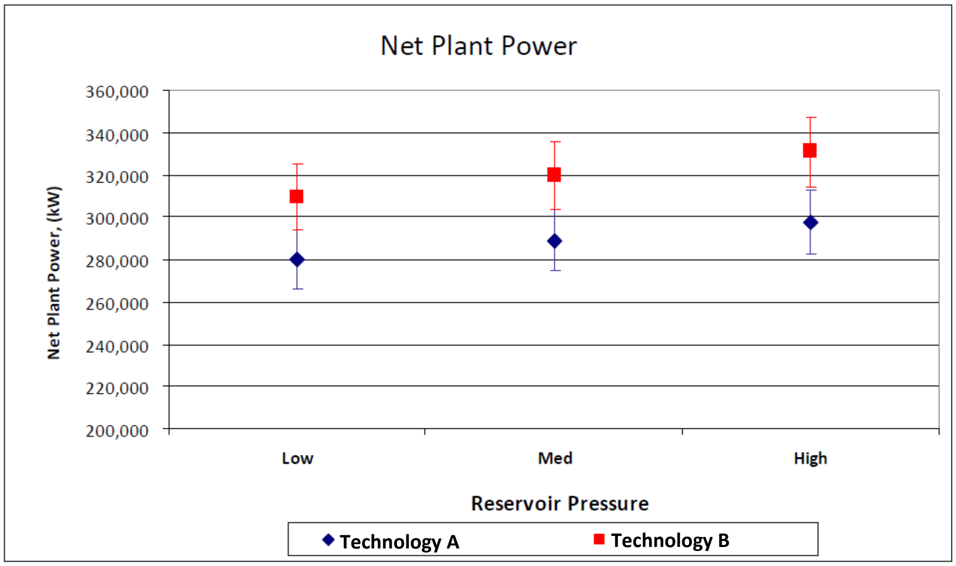


Figure 3-8 Compression Load Versus Reservoir Pressure

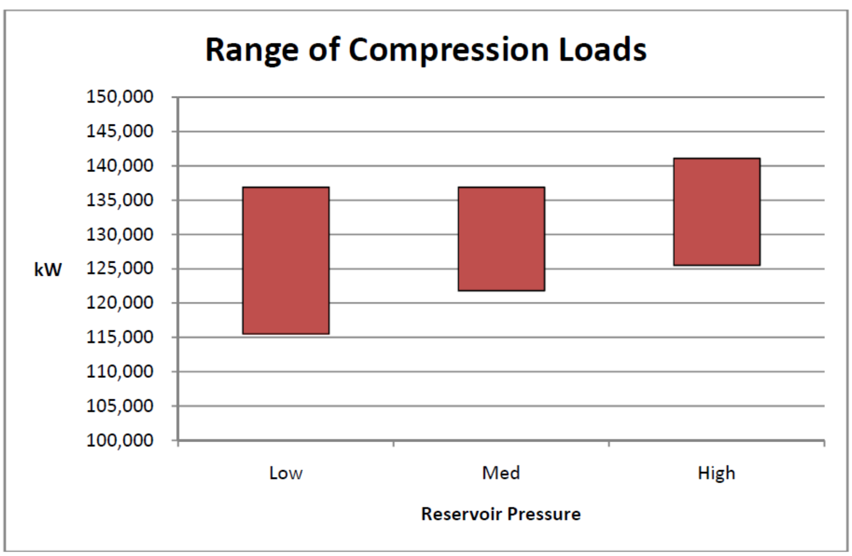


Figure 3-9 Compression Power versus Pressure

3.6.4 Summary

The forecast cost ($/kW) for the Base Case CAES facility is competitive with the cost of conventional power generation technologies. CAES likewise can provide capacity (charging and discharging), energy, and ancillary services for the California wholesale markets.

After defining a competitive Base Case CAES facility, the relative incremental costs of alternative sites can be compared. Figure 3-10 provides such comparison of capital and operating costs relative to the Base Case having the attributes identified in Tables 3-1 and 3-2 and the aggregated results for each site as identified in Figures 3-5 and 3-6).

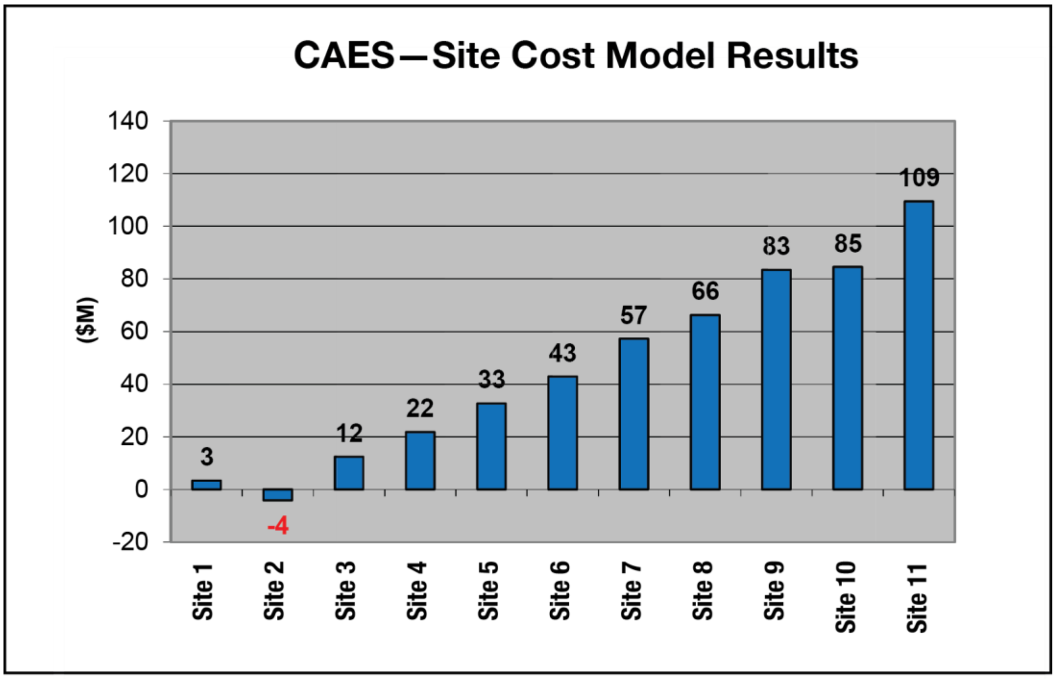


Figure 3-10 Site Ranking

The value for each site is a calculation of its CAPEX and OPEX costs over a 30-year project life, and then discounted back to today's dollars. The value represents the forecasted lifecycle costs over/below the Base Case facility.

Not surprisingly, the top sites were closely related to the top sites identified as part of the reservoir screening process described in Sections 3.3 and 3.4. Because the screening analysis took into account various attributes that are important to developing a CAES facility (high permeability, high porosity, net sand thickness, etc.), it translated into a competitive cost ranking for those sites forecasted to have the properties required for a CAES facility.

When multiple candidate sites are being evaluated against one another, the Cost Model is one relatively straightforward way to keep track of many complicated site elements, each with its own project-specific impact.

References

Audubon California. n.d. Audubon Important Bird Areas website: http://web4.audubon.org/bird/iba/.

Bay Delta Conservation Plan. n.d. Bay Delta Conservation Plan Website: http://baydeltaconservationplan.com/Home.aspx.

California Department of Fish and Wildlife and the California Department of Transportation. 2010. *California Essential Habitat Connectivity Project: A Strategy for Conserving a Connected California.* Available at http://www.dfg.ca.gov/habcon/connectivity/.

California Well Sample Repository. n.d. http://www.wellsample.com/.

CEC (California Energy Commission). 2007. http://docketpublic.energy.ca.gov/PublicDocuments/Compliance/01-AFC-7C/2007/October/TN%2042598%2010-02-07%20Final%20Commission%20Decision%20Including%20Adoption%20Order.pdf.

CPUC (California Public Utility Commission). n.d. http://cvgasstorage.com/CPUC%20Final%20Decision.pdf.

DOGGR (California Division of Oil, Gas and Geothermal Resources). 2002. Access to Well Records. Publication No. PR8S. Effective September.

DOGGR. n.d. Online Production and Injection, OPI. http://opi.consrv.ca.gov/opi/opi.dll.

DOGGR. n.d. Online Well Record, OWR. http://owr.conservation.ca.gov/WellSearch/WellSearch.aspx.

DOGGR. n.d. Publications. http://www.conservation.ca.gov/dog/pubs_stats/Pages/pub_index.aspx.

FAR (Federal Aviation Regulations). n.d. http://www.ecfr.gov/cgi-bin/text-idx?rgn=div5&node=14:2.0.1.2.9.

Kern County. 2006. First Public Draft. Valley Floor Habitat Conservation Plan. Available at: http://www.co.kern.ca.us/planning/pdfs/vfhcp_dec06.pdf.

Nelson, P.H. 1994. "Permeability-Porosity Relationships in Sedimentary Rocks." *The Log Analyst.* May-June.

PG&E. n.d. PG&E Corporate Environmental Justice Policy. http://www.pge.com/includes/docs/pdfs/about/environment/pge_ej_policy.pdf .

Schlumberger. n.d. http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=pressure%20gradient.

U.S. Environmental Protection Agency (EPA). n.d. U.S. EPA definition of "sensitive receptor." http://www.epa.gov/region1/eco/uep/sensitivereceptors.html.

Appendices

Appendix 3A, Attachment 1, Cache Slough Site Selection and Attachments.
Appendix 3A, Attachment 2, Crossroads Site Selection and Attachments.
Appendix 3A, Attachment 3, McMullin Ranch Site Selection and Attachments.
Appendix 3A, Attachment 4, Merrill Avenue Site Selection and Attachments.
Appendix 3A, Attachment 5, Perkins Lake Site Selection and Attachments.
Appendix 3A, Attachment 6, Putah Sink Site Selection and Attachments.
Appendix 3A, Attachment 7, Tracy Site Selection and Attachments.
Appendix 3A, Attachment 8, West Thornton Site Selection and Attachments.
Appendix 3A, Attachment 9, Willow Slough Site Selection and Attachments.
Appendix 3A, Attachment 10, Zamora Site Selection and Attachments.
Appendix 3A, Attachment 11, 111019, Screening CAES Model GIPtoWVol.pdf.
Appendix 3A, Attachment 12, 120127, Evaluation Summary Composite.xls.
Appendix 3A, Attachment 13, 120822, Evaluation Summary Composite.xls.
Appendix 3A, Attachment 14, CAES High Level Review.docx.
Appendix 3A, Attachment 15, CAES Reservoir Size Determination.pdf.
Appendix 3A, Attachment 16, East Islands Cultural Final No Records.pdf.
Appendix 3A, Attachment 17, East Islands BCA Final.pdf.
Appendix 3A, Attachment 18, King Cultural Final No Records.pdf.
Appendix 3A, Attachment 19, King Island BCA Final.pdf.
Appendix 3A, Attachment 20, Master List.xlsx.
Appendix 3A, Attachment 21, PG&E CAES Gas Screening Model, November 2011.

Chapter 4
Site Control

4.1 INTRODUCTION

Site control, for this feasibility study, was the acquisition of all of the rights necessary to:

- Conduct the testing (core drilling and air injection) required to determine the technical viability of the site(s).
- Allow for the development (if determined to be economically and technically feasible), construction, operation, and maintenance of a CAES facility (from well field through the air pipeline and to the Energy Conversion Facility [ECF]).

The rights, to be obtained from various parties, needed to include at a high level:

- Flexibility to deal with the current and future technical unknowns.
  - Duration is sufficient to accommodate long development, permitting, and operational requirements.
  - Enough surface use is available to accommodate the current and future project needs.
  - Siting is sufficiently flexible —for example, in the case of the well field development, to accommodate multiple potential locations for the future well pads.
  - Ingress and egress are flexible (i.e., multiple ways to enter and leave the subject property).
- Commercially reasonable terms
  - Rates are reasonable and can be forecast with some certainty (i.e., tied to known indexes).
  - Terms are reasonable and fully assignable to another entity.

Once these general parameters were established, the potential reservoirs identified, and the preliminary title work completed, discussions were undertaken with the various third-party holders of the rights. These discussions sought to determine if mutual interest existed in entering into a deal and, if so, whether agreement could be reached on the terms and conditions that would govern the agreement. The agreement could last anywhere from 1 year (assuming a site is tested and fails to move forward) or potentially up to 50 years or longer (assuming a site is successfully tested, developed, and operated/maintained).

This chapter reviews the issues associated with site control of the CAES facility. It outlines the ownership structure and legal framework behind use of the site. The chapter also discusses the scope of site control for the various parts of the site, including surface and pore space, minerals, ECF, air pipeline, and linears. Commercial issues are also addressed, relating to the reservoir, mineral rights, the ECF site, and the air pipeline.

4.2 LEGAL FRAMEWORK–RESERVOIR RIGHTS

Given the complexity associated with acquiring the various reservoirs rights required for a CAES facility, a discussion of the legal context was necessary.

1. **Surface and Pore Space.** The law has been relatively well settled in California that the surface (non-mineral) owner is the holder of the right to inject, store, and withdraw substances into subsurface reservoirs (the pore space). However, this right is subject to the dominant rights of the mineral owner or lessee to explore for, develop, and produce oil or gas, and an obligation not to unreasonably interfere with the mineral owner or his or her lessees' dominant rights.

   The case of *Cassinos v. Union Oil Company of California* (14 Cal. Ap. 4th 1770 [1993]) was the first California Appellate Court recognition of that principle. In *Cassinos,* Union obtained permission from the owner of the surface estate to inject and dispose of offsite wastewater. However, the Court found that Union interfered with and damaged wells in the mineral estate to the detriment of its mineral lessee, in that the injected wastewater communicated with oil elsewhere on the lease and resulted in a substantial drop in oil production and an increase in the water-to-oil ratio in the wells. The Court awarded damages against Union, finding that Union's injection of wastewater amounted to a trespass because of its interference with the rights of the owner of the mineral estate. In holding as it did, the Court in *Cassinos* essentially followed the law announced in cases decided in the State of Oklahoma, another "rule-of–capture" state (defined in 2(b) below). In essence, the owner of the surface estate is the owner of the vessel or reservoir, and has such rights to its use as will not unreasonably interfere with the mineral development rights of the severed mineral estate owner.

   The holding in *Cassinos* is limited to wastewater disposal rather than underground compressed air or gas storage (and other uses of the pore space). However, based upon analogy to law in the State of Oklahoma, the breadth of the Court's statement in *Cassinos* is accurate and applies to underground storage of compressed air, underground gas storage, and carbon sequestration the same as it applies to injection of wastewater. Even though California case law has not explicitly stated that the surface owner, not the mineral owner, has the authority to store gas or compressed air in a depleted underground storage reservoir, other states have. In Oklahoma, a rule-of-capture state like California, it is settled that, "the surface owner alone should be compensated for the use per se of a stratum. He is the owner of this formation, and like an owner of a warehouse, he is entitled to the rental or other compensation paid for the use of his property." (*Ellis v. Arkansas Louisiana Gas Co.* [1978] 450 F.Supp. 412, 421.) Similarly, West Virginia law (a rule-of-capture state) provides that the surface owner has the authority to grant a gas storage lease (*Tate v. United Fuel Gas Co.* [1952] 71 S.E.2d 65). And finally, a federal court applying Louisiana law (a rule-of-capture state) stated that, "the general American rule seems to be that the shell of space in which a mineral is originally encased becomes the property of the surface owner by operation of law after all the mineral has been taken therefrom" (*United States v. 43.42 Acres of Land* [1981] 520 F.Supp. 1042, 1045 and fn. 9, quoting an article by Alan Stamm entitled "Legal Problems in the Underground Storage of Natural Gas," found in Vol. 36 of the *Texas Law Review*, at page 161).

The rights to use of the actual surface of the land for drilling injection/withdrawal wells, monitoring wells, wastewater injection wells, pipelines, and utility lines and for an electrical generating plant (ECF) are held by the surface (non-mineral) owner. The surface owners can make such use of the surface as they see fit and in accordance with any land-use restrictions, etc. However, the use of the land cannot unreasonably interfere with the mineral owner's dominant right to make such use of the surface as is reasonably necessary or convenient to explore for, develop, and produce oil or gas.

2. **Basic Mineral Rights–Legal Concepts Under California Law**
    a. Mineral rights can be, and frequently are, held separate and apart from the non-mineral or surface estate, either in fee simple or for a term of years. The severance of the mineral estate from the surface estate may be by grant or reservation (Wall v. Shell Oil Co., 209 Cal. App. 2d 504, 510 [1962]).

    b. California is a rule-of-capture state. A mineral owner, with regard to oil, gas, and other fugacious substances (those that can move between property lines as opposed to hard minerals) does not own the oil and gas in place, but owns only the right to explore for, develop, and produce oil and gas. Native oil and gas become owned only as they are "captured" at the well head (Dabney-Johnston Oil Corp. v. Walden, 4 Cal. 2d 637, 648-649 [1935]).

    c. The rights of a mineral owner to use of the property, as against the non-mineral or surface owner's rights, are the dominant rights under California law. The mineral owner has the right to make such use of the property (including the surface) as is reasonably necessary or convenient to explore for, develop, and produce the mineral substances, and the surface owner cannot unreasonably interfere with those rights (Wall v. Shell Oil Co., supra).

    d. The grant or reservation of "mineral rights," or "oil, gas and hydrocarbon minerals or mineral rights," carries with it an implied right to make reasonably necessary or convenient surface use (Wall v. Shell Oil Co., supra, at 513) unless the surface use rights are expressly limited in the grant or reservation or in a prior grant or reservation of the mineral rights.

3. **Severed Mineral Rights and Underground Storage Projects.** As stated above, a mineral owner holds the dominant right to explore for, develop, and produce oil and gas; the surface (non-mineral) owner holds the right to use of depleted or non-productive subsurface reservoirs, but cannot unreasonably interfere with the mineral owner's dominant rights. Therefore, one can envision a subsurface geologic structure under which no consent to use of a subsurface reservoir from a severed mineral rights holder is required. However, the vagaries of geologic interpretation of the subsurface and developing oil and gas exploration technologies would make it very risky to fail to obtain a severed mineral owner's consent to injection, storage, and withdrawal of compressed air in a subsurface reservoir.

Injection of compressed air into a subsurface reservoir, even for test purposes, will likely limit the ability to produce any commercially producible gas reserves in that reservoir. Also, should any reasonable prospect of commercially producible reserves in deeper zones exist, the use of a higher reservoir for injection and storage of compressed air will render the ability of a mineral owner or lessee to drill into deeper zones to explore significantly more costly. It would also likely be an unreasonable interference with the mineral owner or lessee's dominant rights unless the increased cost is borne by the CAES developer/operator. The opinions of geologists and reservoir engineers as to the prospect of commercial reserves of oil or gas in deeper zones, and even as to the existence of commercially producible oil or gas in the target storage zone, can vary widely. At a minimum, a project could be delayed in a costly manner by a mineral owner or lessee's suit to enjoin the project, and the CAES developer/operator is left to the uncertainty of conflicting expert testimony, if the mineral owner's consent to the project is not obtained ahead of time.

4.3 SCOPE OF SITE CONTROL: ACQUISITION OF RIGHTS

The testing and development of a CAES facility and the associated reservoir include the acquisition of rights from the owners of various properties required for the ECF, well-pad facilities, and all required linears (air pipeline, water pipeline, etc.).

Figure 4-1 shows the primary areas of a CAES facility and the scope of site control needed for each area.

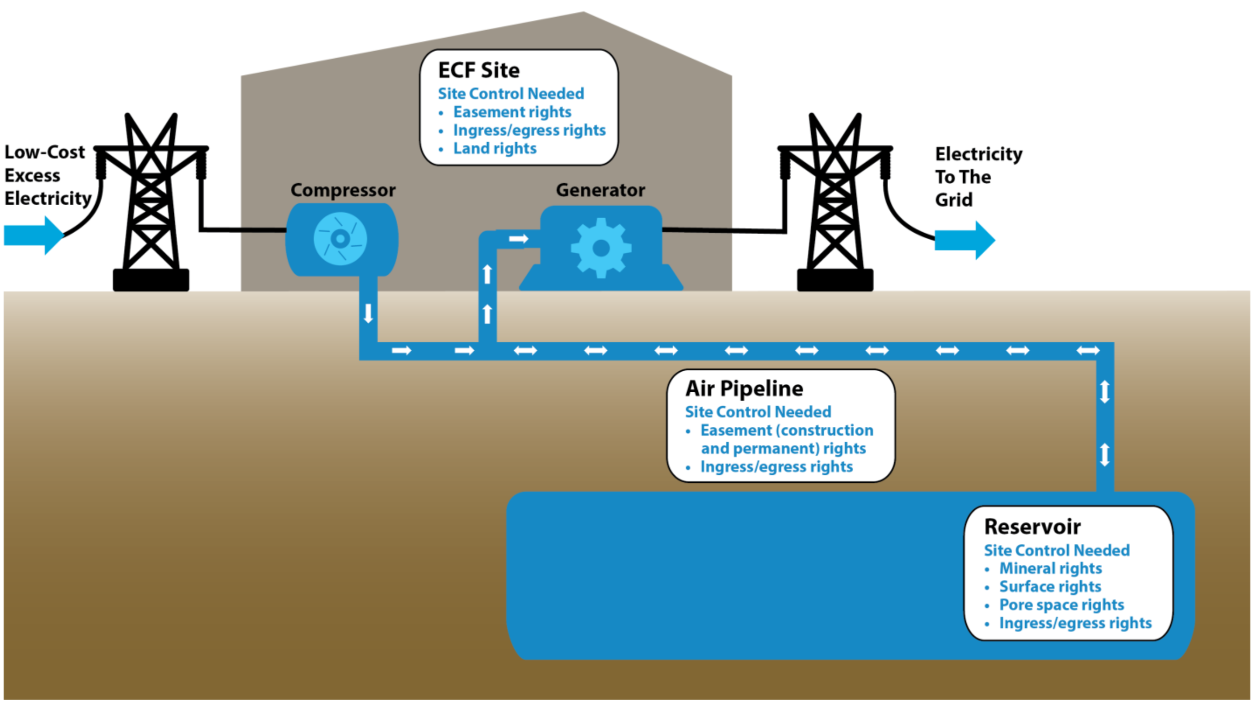


Figure 4-1. Scope of Site Control for CAES Facility (Note: the project envisions one bi-directional pipeline connecting the ECF to the reservoir.)

Developers need to be assured that for the property of interest they have identified all owners, lessees, and title encumbrances such as mortgages and property liens. Prior to actual development, the developers will want to have executed acceptable arrangements with each of the owners regarding their specific rights and the requirements for underground storage development. Depending on the nature of the property owner's rights, these arrangements are typically accomplished through a variety of agreements such as:

- **Leases.** Conveyances of specific rights for a defined period of time. Compensation is typically pre-described and periodic throughout the term of the lease. The rights revert to the owner at the end of the lease term or upon non-performance by the Lessee. Owners typically like leases because they provide for development of a resource and cash flow to the owner without actually giving up permanent rights to the property.

- **Purchase agreements.** Result in a transfer of ownership based on a negotiated price. These agreements are preferred by owners who are comfortable with a fixed price based on the current market conditions and are willing to give up the future cash flow stream of a lease for the certainty of a sale.

- **Easements.** Similar to a lease but much more restrictive as to the rights conveyed to the grantee. These types of agreements are commonly used for infrastructure facilities (either underground or on the surface) and contain certain limitations that provide the owner with ongoing ownership and certain rights to continue operations on the impacted lands.

- **Letters of consent.** Typically used to acknowledge activity by a developer or operator that has the potential to affect an owner's property in some way. These agreements are used by storage developers to document an understanding with the mineral owners as to the developer's plans, but do not require any rights from the mineral owner. The storage development could potentially affect the mineral owner's future activity to access their minerals, so a letter of understanding helps alleviate potential conflicts.

By acquiring the necessary rights, developers can assure themselves that their operations will not trespass onto property not under their control. The types of property typically involved in an underground storage project are related to surface rights (reservoir and the ECF), ownership of the pore space in the reservoir, mineral rights, and any rights-of-way/easements for linears required for the project. Further discussion of each of these rights follows.

4.3.1 Reservoir—Surface and Pore Space

Developing an underground reservoir for storage purposes requires access to certain surface rights. Wells will need to be drilled from one or multiple well pads located directly over or near the reservoir. Pipelines will need to be installed to transport the storage commodity into and out of the reservoir. Flow control, commodity cleanup and treatment, and communication services will be required. The preference is to locate this type of facility near the reservoir if possible.

Two different types of <u>surface</u> rights are often involved in a storage development: 1) temporary and 2) permanent.

1. **Temporary.** For this feasibility study, PG&E acquired the rights to undertake the activities required to test the reservoir's suitability for a CAES project. Directional drilling technology provides some flexibility as to where the drilling/facilities need to be located on the surface to conduct the core drilling (described in Chapter 6) and the air injection test (described in Chapter 6). In general, the project team assumed that one acre would be needed for the well pad development and core well drilling activity. An incremental two acres would then be needed to conduct the air injection test (well pad, injection/withdrawal well, and related testing equipment). Along with these rights, the project also needs to ensure that it has the proper ingress and egress rights (i.e., the right to enter and leave the property) via the use of existing and/or new (if required) roads, and any easement rights that may be required to support the temporary/testing phase (i.e., ability install power lines to support the air injection testing).

   Development of the storage field, drilling of the necessary wells, installation of the pipelines, and construction of the surface facilities may all require more space than will be needed for the ongoing operation. These temporary arrangements (i.e., construction and/or laydown agreements) are typically made with the surface owner through a short-term lease to compensate for the use of the required space as well as for any damages to crops or infrastructure that may occur. Once the construction activity is complete, the lease customarily terminates, and use of the land reverts back to the property owner.

2. **Permanent.** Once the facility is developed, the owner/operator would require permanent rights necessary for the ongoing operation and maintenance of the storage facility for as long as the storage operation continues. The number of wells and associated facilities required for the permanent facility is driven by the geological properties of the reservoir and the size of the project. In general, the project team assumed that one to two well pads with a total footprint of ten acres would be needed. The three acres of disturbance associated with the core drilling (one acre) and air injection test (an incremental two acres) would be a component of the ten acres in total (i.e., not incremental to the ten acres).

   The land necessary for the surface facility and well pads can be acquired either in fee or through a long-term lease. Pipelines are typically below ground, and as a result, their rights-of-way have different restrictions than those for the surface facility. Most pipeline easements or lease agreements will allow for the property owner to resume certain operations within the right-of-way provided those operations do not represent a risk to the underground pipeline or inhibit access for maintenance purposes.

   In situations where the surface is subject to pre-existing leases for farming or other operations, separate agreements may need to be negotiated with the lessee to minimize conflict with their activity and provide for compensation for any damages.

   As with the temporary rights, the permanent rights should include the rights to ingress and egress as well as any easements/rights-of-way required to support the permanent facilities.

In California it has been established that the surface owner also owns the rights to the pore space (see above, Section 4.2.2, "Legal Framework—Reservoir Rights," no.1, "Surface and Pore Space"). As such, the agreements between storage developers and surface owners include not only the surface access requirements outlined above, but also an arrangement providing for the use of the pore space for storage purposes.

In terms of how much pore space to acquire, agreements are executed for sufficient area to cover the entire underground reservoir, plus some amount of buffer area to deal with geological uncertainty, encroachment mitigation, and possible migration issues. A number of resources are essential in establishing not only the limits of the existing reservoir, but also where the stored gas may go once it is injected into the reservoir. These resources include geological interpretations based on logs from previously drilled wells, production data as available from the California Division of Oil, Gas and Geothermal Resources (DOGGR) or other sources, and available 2D or 3D seismic data. Each reservoir needs to be evaluated carefully to establish the storage boundary, within which storage rights will be acquired, and to ensure the long-term integrity of the reservoir for storage purposes.

4.3.2 Reservoir–Minerals

Mineral rights are often subject to agreements and obligations entirely separate from those listed above for surface and pore space. In fact, the mineral rights are commonly severed from the surface rights and are owned by different parties. As discussed above (see Section 4.2.2, "Basic Mineral Rights—Legal Concepts under California Law," 2[b]), "the mineral owner holds the dominant right to explore for, develop, and produce oil and gas . . . ," which may be in conflict with the surface owner's interest in developing a particular reservoir for the purpose of storing gas underground. As such, an agreement must be struck with the mineral owner to ensure that the storage development will not interfere with their right to explore for, develop, and produce oil and gas. In the case of a depleted reservoir, this agreement is typically accomplished by a consent agreement where the mineral owner acknowledges the depleted nature of the reservoir and consents to the surface owner's use of the reservoir for the development of underground storage.

Mineral rights are often subject to oil and gas leases, both those currently effective and those that have expired but are still "of record." Good title research is necessary to sort out current leasehold obligations and any curative work necessary to deal with expired leases. Because lessees have been granted the right to explore for and produce oil and gas reserves from the mineral estate, the storage developer will often need to negotiate an agreement with the lessee as well as the mineral owner to avoid potential conflicts.

4.3.3 Surface–ECF

As a result of the validation of the ECF bifurcation discussed in Chapter 4, the siting envelope for the ECF location greatly expanded. PG&E's preliminary review of the required ECF footprint determined that 20 acres would be needed to accommodate a 300-MW facility (see the preliminary General Arrangement in Appendix 4A, Attachment 1, SmartCAES Suggested Arrangement.pdf, which was developed early in the project to help guide the siting effort). In addition to the acreage, certain easement rights (for electric and gas interconnects, water interconnects and the air pipeline) must be included in any ECF agreement as applicable. In addition, other rights, such as the right of ingress and egress, need to be included.

Considerations should also be given to the need to acquire any temporary land rights for construction parking and laydown areas needed for the future construction of the facility. The land required may or may not be available from the ECF landowner; any agreement for these rights should be flexible enough to work with the expected construction timeframes. Because the land will be temporarily disturbed (prior to being returned to its original condition), the site will need to be identified, and biological and cultural surveying will need to be conducted prior to submitting an Application for Certification (AFC) to the California Energy Commission (CEC) for authority to construct the facility.

4.3.4 Air Pipeline

Because of the need/decision to bifurcate the ECF from the reservoir, PG&E also needed to acquire easement rights to construct, install, and operate an air pipeline that would connect the reservoir with the ECF. It was anticipated, based on similar pipeline construction work, that the construction easement needed was 100 feet wide and the permanent easement was 50 feet wide. Easement rights for an air pipeline should include any temporary rights needed for construction as well as the permanent rights.

4.3.5 Linears

Along with acquiring the various rights described in each area above, PG&E also needed to understand the various linears (other than the air pipeline) that would be required to support the various project facilities on either a temporary and/or permanent basis. Based on that review, PG&E had to ensure that all agreements (ECF, reservoir agreements, etc.) include associated easements and/or rights-of-way.

The surface rights at the reservoir should account for linears associated with power lines and pipelines (gas, water, and/or air). At the ECF location, any agreement must include easement rights needed for electric transmission, gas pipelines, air pipelines, and/or water.

4.4 COMMERCIAL ISSUES

During site acquisition efforts, numerous commercial issues arose. This section summarizes the most pertinent issues relating to: the reservoir, ECF site, air pipeline, and other agreements.

4.4.1 Reservoir—Surface and Pore Space

Discussion regarding site control at the various reservoirs generally revolved around two main concerns: length of term and use conflicts.

Length of Term

Underground storage rights can be acquired in perpetuity, in fee simple for a lump sum payment, but are generally acquired as a leasehold. The term of an underground storage lease should be for an operating term that at least equals and probably exceeds the expected life of the generating plant, taking into account any refurbishment of the plant that may occur (say, 40 to 50 years with an option to extend). Testing will need to be conducted to evaluate the reservoir before full development of a CAES project. A storage lease can be set up with two terms: (1) a testing term (say, three to five years) with limited drilling and injection testing rights, during which the rentals may be lower; and (2) at the lessee's election, a development and operation term, at a higher rental, in which the lessee will have all development and operation rights.

Use Conflicts

Surface uses by the surface (non-mineral) owner, and existing mineral development or potential mineral development by the mineral owner or lessee, can create constraints that may or may not be able to be accommodated. Several types of surface use may require creative work-arounds:

- **Sensitive, high-value permanent crops.** Vine and tree crops can be valuable and expensive to pay for if required to be removed to accommodate drilling, pipelines, ECF sites, or access. Permanent irrigation or drainage systems may also be affected by surface CAES uses. The option of locating wells offsite and using directional drilling should be analyzed, and the increased cost (and complexity if option requires the need for a new agreement with a different landowner) should be compared with the required payment for crop loss and irrigation and drainage fixes. Onsite locations causing less damage to crops and systems may exist, and pipelines may be able to be routed beneath access roads or along parcel perimeters.

- **Conservation easements and agricultural land preservation easements; mitigation lands.** Increasingly, landowners are entering into conservation easements or agricultural land preservation easements or creating mitigation banks. These uses severely restrict surface uses except, typically, for designated farmstead or other areas. Exploration for oil and gas is also typically allowed, with limitations, in some of the less-sensitive land areas. Surface facilities for a CAES project should be located offsite or within farmstead areas, if possible.

- **Duck/hunting clubs.** Hunters and hunting club owners are particularly sensitive to surface activities during hunting season periods; accommodations may need to be made to avoid certain months of the year during testing and construction. Permanent fixtures such as well heads, dehydrators, valves, etc. should be painted a drab color.

- **Williamson Act**. The California Conservation Act of 1965, commonly referred to as the Williamson Act, is a program in which farmers enter into an agreement with the State of California that restricts the allowable use of property owned by that farmer for the purpose of keeping land in active agriculture or open space. In return, the landowner's property taxes are assessed at a lower rate. Owners of property in the Williamson Act may cancel their contracts by filing a notice of nonrenewal; a cancellation fee would typically be required of the landowner, roughly equal to the value of the tax benefit that they have previously received.

General Discussion

The length of the term of the leases and agreements typically was not an issue. The majority of property owners had past experience with oil and gas leases, and were familiar with terms of 50 years and beyond. However, in some instances, due to the level of compensation, owners expressed concerns about being able to sell property if it was encumbered by a compressed air lease and sought to negotiate a shorter term. Their concern was that a potential buyer may want to consider exploring for natural gas at depths below the storage reservoir and be deterred by a compressed air lease on the property. In these cases, PG&E needed to explain that, from the expert opinion of the project's petroleum engineers, no commercially retrievable reserves exist at deeper depths in the gas field; a compressed air lease may, therefore, be seen as a benefit, providing a known revenue stream. Since all the leases and agreements must run in concert with the life of a CAES project, a reduction in the term of any agreement was not acceptable.

In those instances where some amount of natural gas production is still under way, the continued operation of those existing wells may be allowed during the testing phase. If workable, this arrangement would allow the existing leaseholder to continue receiving revenue from their existing operations. However, when and if the decision is made to fully develop the reservoir for CAES, the continued operation and production of those gas wells will need to conclude.

Most of the storage reservoirs identified for CAES were sited in rural agricultural areas. Due to the perceived impact to their operation, owners were opposed to taking any agricultural land out of production. When surface impacts such as well pad expansion were necessary, compensation on a per-acre basis was much higher than pore space rentals. Compensation was calculated by multiplying the acreage taken out of production by a dollar amount representative of the current use. In these cases, PG&E cited values published in a local agricultural index.

Drilling and operating injection/withdrawal wells, monitoring wells, or wastewater injection wells for a CAES project should be no more intrusive or destructive to conservation or agricultural values than for oil or gas exploration and development. However, disclosure must be made to the easement holder (and frequently the referenced resource agencies), and their written consent should be obtained. Careful consideration must be given to the long-term impact on the habitat and its environs and the likelihood for successful development/permitting; early outreach with stakeholders should occur to review the area and the potential impacts to determine potential development solutions.

4.4.2 Mineral Rights

Several potential issues arose with mineral rights, especially when these rights have been severed from the surface (non-mineral) ownership.

- **Highly fractionalized severed mineral ownership.** As mentioned previously, mineral ownership commonly becomes held in smaller and smaller percentages by more and more mineral owners. This trend can make obtainment of consents to the storage of compressed air very difficult, and sometimes impossible. Mineral interests may also be ignored in the estates of deceased mineral owners. Probating small mineral ownerships can be cost prohibitive.

- **Active oil and gas leases and expired but un-surrendered oil and gas leases.** If an active oil and gas lease is on a property, a consent to the storage of compressed air must be obtained from the oil and gas lessee as well as from the mineral owner. If active production is under way, that consent will, of course, be more difficult to obtain. If the production is above the target storage reservoir, the storage operation should not interfere with production. However, if any reasonable prospect exists of production of gas from the storage reservoir or from deeper zones, obtaining consent becomes much more difficult. Accommodations can be complicated and expensive with the oil and gas lessee and mineral owner regarding remaining recoverable gas in the storage reservoir or exploration of deeper zones by drilling through or around the storage reservoir.

- **Recalcitrant mineral owners**. Most mineral owners will not understand two key legal points: 1) The right to use of a depleted or non-commercially productive subsurface reservoir is vested in the non-mineral (surface) owner, subject only to an obligation not to unreasonably interfere with the mineral owner's dominant right to explore for, develop, and produce oil and gas; and 2) California is a "rule-of-capture" state (see definition below) such that the mineral owner does not own any oil or gas in place, but owns only the right to explore for, develop, and produce oil or gas, which is then owned only when "captured" at the well head. Thus, the mineral owners need to be educated on these points. The mineral owner may be accustomed to receiving annual delay rentals (i.e., annual payments to the owner up until oil or gas are produced; once oil or gas is produced, the annual payments are terminated and replaced by a royalty on what oil or gas is produced and then sold).

General Discussion

Mineral Owner Consent Agreements proved to be one of the more difficult agreements to enter into with a severed mineral owner for various reasons. In many cases, the mineral rights had been severed from the property such that two, or more, different parties could hold rights over the same parcel. In some instances, rather than entering into separate agreements with each party, attempts were made to consolidate all the interested parties using a Mineral Management Agreement. A Mineral Management Agreement would allow the nominated manager of a pool of severed mineral owners to negotiate and enter into agreements for the group. In some cases, the mineral rights were severed from the property long enough ago that the current owner was unaware of its ownership.

The issues associated with mineral consents become somewhat more complicated in the case where the reservoir is mostly, but not entirely, depleted of its commercially producible native reserves. (Most often, reservoirs contain some amount of natural gas that cannot be commercially/economically produced today. The costs to extract, including required infrastructure, do not provide economic returns required by the developer.) In some cases, the mineral owner believes that the remaining reserves represent a future income source should it become economic to extract the reserves (i.e., cheaper methods of extraction, higher commodity prices, etc.) and their ability to continue production is most likely affected by the storage development. In this case, the storage developer typically compensates the mineral owner for their lost income opportunity as part of the overall consent agreement.

Mineral owners are often reluctant to give up on any future exploration potential on their property, and will likely restrict the underground storage rights to the storage reservoir formation only. Likewise, storage developers want to protect their storage investment. To achieve both parties' interests, terms will often be included in the consent agreement that provide the mineral owners with ongoing access to their property without undue interference from the storage development, while assuring some level of protection for the storage reservoir from encroachment during additional exploration. This balance can be accomplished by agreement on such items as the timing of drilling exploratory wells, the design of the exploratory and production wells, the sharing of geological information, and periodic communication about future exploration and development plans so that potential conflict issues can be sorted out in advance.

In these instances, the mineral owner consent agreements may provide for drilling around or through the storage reservoir to test or produce deeper zones, with protective measures such as casing the well bore through the storage reservoir to be agreed upon with the storage operator. The increased cost of drilling around or through the storage reservoir may need to be reimbursed by the storage operator to avoid a claim of unreasonable interference with the mineral owner's or lessee's dominant rights.

Steps should be taken to be able to show that the storage reservoir has been fully depleted of commercially producible reserves. It would also be helpful to demonstrate that zones deeper than the target storage reservoir are not commercially prospective for economically reasonable reserves (that deeper zones have been tested or fully depleted). In some cases, to overcome objections, discussions had to include bracketing the depths of the consent.

Mineral owners who had at one time held oil and gas leases were accustomed to much higher rentals (fixed monthly payments) plus royalties. Delay rentals from oil companies typically ranged from $10 to $50/acre. Mineral owners may expect to be compensated for any gas (even though it is not commercially recoverable) in the depleted reservoir, believing that he or she owns the gas in place. In some instances, discussions revolved around paying a royalty on any natural gas recovered and sold at the well head to alleviate these concerns

The level of compensation to a property owner was also a difficult obstacle to overcome. No established market exists in California for compensation of non-mineral (surface) owners for underground compressed air storage, either in terms of rental for a leasehold interest or payment for an outright purchase of storage rights in fee. Reference to rentals paid for underground natural gas storage is not terribly helpful, because the rents, based on the value of the natural gas, are generally higher than can be economically paid for by storage of compressed air. Basing rents on a percentage of gross or net income would require taking into account the future, unknown conversion of compressed air into electric energy, and the costs of building and operating the facility.

4.4.3 ECF Site

Discussion regarding site control for an ECF site generally concerned three main issues: 1) land requirement, 2) lease vs. purchase, and 3) easement rights.

Land Requirement

Due to the rural nature of the sites, the majority of the identified ECF sites were farmland. A preliminary General Arrangement (GA) produced for the project established that a 20-acre footprint was preferred. For future considerations, an additional 10-20 acres would also be required temporarily for construction, laydown, and parking areas should a permanent facility be built.

Three main items were identified:

1. The major concern of most property owners was minimizing the potential impacts to farming operations by reducing the footprint and identifying a parcel that minimized impacts on their current operations.
2. Property owners were concerned about the noise and visual impacts associated with the ECF.
3. Since the size of most agricultural parcels far exceeds the footprint requirements for an ECF, partial takes of the larger parcel were presented to the owners. A partial take of a larger parcel is not a problem for a public utility with an exemption from the Subdivision Map Act. However, since the project needed to account for the potential that the development of a CAES project would be by an Independent Power Producer (IPP), which does not have this exemption, the developer would need to apply for a new assessor's parcel map from the County prior to executing the Option and purchasing the property in fee.

Lease vs. Purchase

When securing the land needed for the ECF, PG&E employed both an Option to Purchase and an Option to Lease (occasionally, property owners approached with an Option to Purchase, objected to selling any property in fee and preferred to lease the land). An Option to Lease was acceptable as long as the term of the lease matched the expected life of the ECF.

Easement Rights

Optioned property is often surrounded by other property owned by the Optioner. The need to install infrastructure that may require a permanent or temporary disturbance of the land to the optioned property is obviously important to the success of the future development. Careful consideration must be given to ensure that these rights are included in any agreement.

General Discussion

PG&E worked with the various landowners to identify parcels that would minimize impacts to current operations/infrastructure. For instance, PG&E worked with property owners to identify parcels near to or adjacent to existing roads so as to minimize the need to construct new roads. Additionally, PG&E identified parcels (size/shape) that would work for the project and not leave the property owner with portions of land that were isolated from the remaining parcel, making it difficult to farm and/or requiring costly fixes to irrigation, etc.

During discussions with the property owners, PG&E discussed local noise ordinances and how the CAES facility compared visually to other power plants to get the owners comfortable with the project's presence.

The Subdivision Map Act (the "Act") generally prohibits a property owner from dividing his or her land for purposes of sale, lease, or financing without complying with the applicable requirements for preparing and having approved a map or maps depicting the subdivided land (Gov. Code §§ 66424, 66499.30). Certain types of subdivisions are wholly exempt from the requirements of the Act, none of which are applicable here.

For those subdivisions that are not exempt, the Act generally requires a tentative and final map for subdivisions creating five or more parcels (Gov. Code § 66426) and a parcel map only for subdivisions creating fewer than five parcels (*id*. at § 66428). However, the Act excludes certain types of subdivisions when counting parcels: Any conveyance of land to or from a governmental agency, public entity, or a *public utility* shall not be considered a division of land for purposes of computing the number of parcels (*Id*. at § 66426.5 (regarding tentative and final maps) and § 66428(a)(2) (regarding parcel maps)).

Under the noted exceptions to the map requirements, a lease of only a portion of a parcel of land to PG&E, a public utility, would not constitute a subdivision for purposes of determining the number of parcels that are subdivided and which type of map would be applicable. Thus, neither a tentative and final map nor a parcel map should be required under such circumstances. Similarly, an option to purchase a fee interest in favor of a public utility, or the subsequent exercise of such an option by the public utility, would not trigger the map requirements under the Act. Moreover, <u>upon acquiring the leases and options to purchase</u> (or acquiring fee interests upon exercising the options to purchase), the conveyances thereof to another entity, even if not a public utility, would not trigger the map requirements because the noted exceptions include both conveyances to *and from* public utilities.

However, should a public utility acquire an option to purchase a fee interest, and thereafter convey that option to a non-public utility without first exercising the option, the subsequent exercise of the option by the non-public utility would likely trigger the map requirements. Therefore, in that situation, a public utility would want to consider exercising the options that it acquires to purchase the fee interests before conveying the associated land to a non-public utility.

To acquire the rights necessary to build an ECF at the location(s) identified, either an Option to Lease or an Option to Purchase agreement (depending on the preference of the landowner to sell or lease) would be executed at the preferred site(s). In exchange for an agreed-upon annual payment, PG&E and/or its assignee would have a period of time in which to exercise its right to lease/purchase the property. These agreements were of a duration (five to six years) that would allow PG&E to complete its feasibility study, gain regulatory approval for any long-term Energy Storage Agreement (ESA) executed as an outcome of the Request for Offer (RFO) process (see Chapter 10), and start any required permitting approvals prior to the need to trigger the Option.

The general features of the Option Agreements were:

- Five to six years prior to the requirement to trigger the option; for a lease, if the option is triggered, up to a 50-year lease term with the right to extend.
- Annual option payments during the five- to six-year option period.
  - Calculated as a negotiated percentage of the agreed-upon strike price, or annual rental amount, divided by the number of payments due over the term of the agreement.
  - Payments would typically increase either after a certain amount of years passed after entering into the Option, or annually after the first anniversary.

- Established purchase or lease price on a $/acre basis.
- In some cases, the ability to credit some percentage of the option payments toward the future Purchase and/or Lease price.

Upon exercising the Option, either the purchase price would be paid to the owner to acquire the property in fee simple, or annual lease payments would start to be made to the owner for the life of the project/lease.

In general, owners approached with an Option to Purchase all insisted that the value of their property was substantially higher than market comparables for various reasons: 1) potential commercial development, 2) plans to plant the property as vineyards/higher value crops, or 3) lack of available land in the immediate area. Good market research and a list of comparable sells/listings can assist the process.

Property owners understood the need to include easements as a component of any agreement. Their main concern was to limit the amount of land affected and understand any restrictions to their operations that may be associated with those easements (i.e., no building/planting on the easement, etc.). Easements, where appropriate, were based upon industry and/or permitting requirements.

4.4.4 Air Pipeline

Many of the issues discussed already (amount of land required for a permanent easement and any restrictions, permanent or temporary disturbances, compensation, etc.) were relevant when discussing acquiring the rights necessary for the air pipeline.

A major concern for property owners was the high pressure (2,000 psi) that the pipeline would be operating under and any safety-related concerns. To address these concerns, PG&E explained that several factors contribute to the safe design and operation of any pipeline. All of these factors would be subject to public review and permitting decisions by various lead government agencies prior to any pipeline being installed and operated. This process will include providing a detailed stress analysis, along with certified drawings corresponding to the results of the stress analysis. During operation of the air pipeline, various safety devices and systems will be installed to monitor its safe operation.

In cases where the air pipeline alignment may go under or along a levee, owners had concerns about how this placement might affect the structural integrity of the levee. In this case, PG&E explained the design and review process that is involved with borings under levees. Many levees have Reclamation Districts that are responsible for their management; the Reclamation District’s engineer would participate in the engineering review.

4.4.5 Other Agreements–License to Conduct Site Surveys

Upon identifying a subject property, but before entering detailed negotiations, PG&E often found it helpful to visually inspect the property. Licenses were often entered into to allow for the visual screening of various sites. Upon entering into one of these no- or low-cost agreements, PG&E-directed biologists and cultural resource specialists could perform visual surveys of the property to identify any conditions that would preclude the use of the property and/or significantly add to the development cost of the project. In no case did these agreements allow any digging, boring, or soil samples of any kind.

These licenses were useful, simple tools to allow for access to the subject property and to build trust with the various property owners by showing that the project had a vested interest in moving towards completion of a larger agreement. Despite the fact that these licenses were simple and limited as to scope and duration, two main concerns were typically raised: 1) indemnification of the owner if any damage or injuries occurred while performing the survey, and 2) PG&E's responsibility to report its findings to external groups.

Appendices

Appendix 4A, Attachment 1, SmartCAES Suggested Arrangement.pdf.

Chapter 5
Core Drilling, Completion, Logging, and Analysis

5.1 INTRODUCTION

Based on data available from public sources, PG&E screened depleted gas reservoirs in California for the appropriate characteristics to support a 300-MW CAES project. This screening evaluated such attributes as reservoir size, depth, thickness, estimated porosity and permeability, the number of wells in the reservoir, the estimated current reservoir pressure, surface ownership, and other items (see Chapter 3). That screening process led the project team to the selection of two sites, King Island and East Islands, which were judged to have the best potential for CAES development.

Further evaluations of these two sites were deemed necessary to refine the data such that a more robust analysis of the potential risks and opportunities could be performed. These evaluations included the drilling of one core well into each reservoir for the purpose of obtaining core samples, which could then be analyzed in the laboratory for specific reservoir properties. The core well would also provide an avenue for running a complete set of modern well logs.

This chapter focuses on the goals and objectives of the coring program, the permitting, the contracting and construction requirements to support the coring program, a description of the coring program, and a summary of the coring results.

5.2 CORE WELL OBJECTIVES

The primary objective for drilling a core well and the subsequent evaluation of the cores was to refine the reservoir analyses (conducted as part of the reservoir screening process identified in Chapter 3) through the acquisition of high-quality data. This additional data would allow the site with the greatest likelihood of achieving a successful CAES development to be confidently selected. Prior to extraction of the cores from each reservoir, the reservoirs had been modeled based upon publically available, and not always completed, data. This broad objective encompassed many sub-objectives discussed in more detail below.

The project team recognized the need to select more than one suitable site to conduct parallel evaluations. For this reason, the project team decided that at least two sites needed to be chosen so that the coring evaluation and log integration would go on essentially simultaneously at the two sites. In this manner, a single fatal flaw at one site would not have a significant impact on the project schedule because another site would be available for testing/development should the preferred site have a fatal flaw.

Several objectives for the core wells were established for the selected sites. Some of these objectives have to do specifically with the data to be obtained from the core samples, and others are related to other important data obtained during the well drilling and completion operations. These objectives were:

1. **Improve the Geological Database** – The geological interpretation for each site had been completed based on available well log and seismic information. In some cases, the available

data was quite limited due to only a few wells in and around the prospective reservoir. Additional data from the core well, primarily from the well logs, was incorporated into the geological interpretation, improving the quality and reliability of the geologic static and reservoir models.

2. **Analyze Reservoir Rock Properties** – The core samples obtained from the core wells were subjected to numerous tests in the laboratory to determine such properties as porosity, permeability (both horizontal and vertical), fluid saturation, grain size, and others. These properties were determined at various selected depths based on a visual inspection of the entire core by an experienced geologist. The properties determined from these tests were critical in updating properties in the static model.

3. **Determine Caprock Properties** – Similar to the analysis of core samples obtained from the reservoir rock discussed above, those samples from the caprock are also essential for the development of the reservoir for air storage. It is critical to establish the competence of the caprock to ensure that air will not migrate from the reservoir when re-pressurized or over-pressured for storage. The data obtained from the caprock samples is also very important in assuring the permitting agencies that the reservoir will not leak if operated within an established pressure range. One key parameter of the caprock testing is the threshold pressure or the delta pressure above which gas will begin to flow through the caprock.

4. **Conduct Reservoir Pressure Tests** – Downhole testing of reservoirs can provide valuable information about the quality of the rock and its ability to sustain flow within the reservoir under various conditions. Repeat formation testers are one tool used to conduct mini-flow tests to obtain pressure and flow rate information that can be interpreted to obtain reservoir rock properties. These in-situ results can be compared with the actual laboratory results obtained from the core samples for correlation purposes.

5. **Obtain Reservoir Fluid Samples** – Fluid samples can be analyzed for various properties that can be useful in the dynamic modeling of the gas reservoir and aquifer, as well as in the permitting process. In particular, the salinity, as measured by total dissolved solids, is a critical factor in determining the depth of the Underground Source of Drinking Water (USDW). For storage development purposes, the depth of the USDW is an important marker in the design of the permanent injection/withdrawal and observation wells.

6. **Determine Design and Location of Core Well for Observation Purposes During Testing** – The location of the core well at each site was based on primarily two factors. The first factor was to ensure that its location would facilitate achieving the other five objectives described above. The well needed to be in a good structural location to obtain the geological information, and also in a portion of the reservoir to ensure the core samples were representative of the majority of the reservoir as it was understood at the time. The second driver for the location of the well was to ensure that it could be used for an observation well during the compression testing phase. Having an observation well located at some distance away from the injection/withdrawal well would be very valuable in collecting reservoir performance data during the compression testing.

For each of the selected coring sites, the depths and intervals for each coring run were selected to achieve the stated objectives. The top of the coring operation was based on acquiring approximately 30 ft of caprock core, and then coring acquisition would continue through the entire productive section of the reservoir, to below the original gas-water contact.

5.3 PERMITTING PROCESS AND RESULTS

Prior to conducting any site work, PG&E needed to acquire the necessary permits and/or regulatory authorities to conduct the envisioned work. The following sections outline this process.

5.3.1 General Approach

As identified in Chapters 3 and 4, a short list of potential storage reservoirs was developed, along with the preferred location on/above the reservoir to conduct the core-drilling operation. Once adequate site control was obtained for the proposed core drilling, a preliminary environmental and permitting assessment was conducted for the area surrounding the proposed 120 ft by 220 ft drilling pad and any access routes. In some cases, the drill pad location was shifted based on environmental or owner-related issues. Various permitting activities were undertaken for each reservoir site, although only the King Island and East Island sites were selected for core drilling and were fully permitted as required. The following results focus on those two sites.

5.3.2 Permitting Jurisdictions

A combination of federal, state, and local permits are typically required for the type of activity associated with the core-drilling effort. The following provides a discussion of the applicability of the potential permits to the project.

Federal

Since the CAES project was partially funded by the federal Department of Energy (DOE), DOE environmental procedures under the National Environmental Policy Act (NEPA) required preparation and approval of an Environmental Questionnaire (EQ). The EQs prepared for the two short-listed sites (and one optional site) are included in Appendix 5A, Attachment 18, PG&E EQ Interim Action Memorandum King-East-Cache.pdf. The EQ checklist addresses typical environmental issues, including land use, vegetation and wildlife, socioeconomics, historic and cultural resources, air quality, hydrology, hazardous waste, health and safety, waste management, and regulatory requirements. In addition to compliance with NEPA, DOE is required to comply with Section 7 of the Endangered Species Act and Section 106 of the Historic Preservation Act.

To support DOE compliance with these two resource-specific laws, PG&E conducted field surveys of the proposed well pad site areas and prepared biological and cultural resource reports addressing potential impacts to these resources. The reports prescribed Avoidance and Minimization Measures (AMMs) as part of the project design. Copies of these reports were provided to DOE with submittal of the EQ, and the biological reports were used to informally consult with the U.S. Fish and Wildlife Service regarding potential impacts to federally listed species. The biological and cultural resource reports for each of the two short-listed sites are included in: Appendix 5A, Attachment 7, East Island Cultural Final No Records.pdf; Appendix 5A, Attachment 9, East Island BCA Final.pdf; Appendix 5A, Attachment 14, King Island Cultural Final No Records.pdf; and Appendix 5A, Attachment 15, Kings Island BCA Final.pdf. No other federal permits or reviews were required for the proposed work.

State

The three state agencies with jurisdiction over some aspect of the proposed core-drilling activity include the Division of Oil, Gas & Geothermal Resources (DOGGR), California Department of Fish and Wildlife (CDFW), and the California Regional Water Quality Control Board (RWQCB). A description of the permitting requirements of each agency is described below.

DOGGR regulates all gas and oil well drilling in the state. A key role of the agency is to establish "field rules" for well drilling and well operation/maintenance for each natural gas field. Field rules may expire after a gas field has been depleted and production discontinued. Where field rules are still active, issuance of a well drilling permit is considered ministerial. However, where field rules must be re-established, DOGGR must conduct an environmental review of proposed new field rules and drilling activity under the California Environmental Quality Act (CEQA). Both of the short-listed reservoirs have active field rules. The issued well drilling permits are included in: Appendix 5A, Attachment 19, PGE MORAIS 16-2 612-0397.pdf and Appendix 5A, Attachment 20, PGE PIACENTINE 2-27 612-0396.pdf.

CDFW manages the state's fish and wildlife resources, including species that are protected as threatened or endangered under state law. To ensure the project activities did not result in impact to state-listed species, the biological studies prepared for submission to DOE included all state-listed species, as well as any other sensitive species of concern to CDFW. Appropriate AMMs were included in the biological report to address any potential impacts to these species.

RWQCB manages the federal National Pollution Discharge Elimination System (NPDES) program in California and has prepared regulations for addressing Construction Storm Water runoff from sites greater than one acre. A Notice of Intent (NOI) was filed with the RWQCB and a comprehensive Storm Water Pollution Prevention Plan was prepared and implemented at the two sites where core wells were drilled.

Local

As a regulated public utility, PG&E's activities are subject to the exclusive jurisdiction of the California Public Utilities Commission (CPUC). As such, the CPUC pre-empts local *discretionary* land-use approval authority, but requires utilities to obtain local *ministerial* permits. For the scope of the proposed core drilling, a local ministerial Improvement Plan for Oil & Gas Well Drilling approval was required from San Joaquin County for both King and East Islands. The objective of this local approval is to ensure the well-drilling activity does not affect adjacent landowners or uses (noise, light, and glare), and that the activity complies with other county engineering and safety ordinances (site development, hazardous materials, and fire safety). As long as the standard permit conditions for gas well drilling and site restoration can be met and are agreed to by the applicant, the permit is issued.

The other local agencies with jurisdiction over the proposed core-drilling scope at the locations selected were the local Reclamation Districts that are responsible for maintaining selected levees, in the vicinity of the drilling activity, in the Sacramento – San Joaquin River Delta. An encroachment permit was obtained for the use of access roads on the top of District levees, with the objective of ensuring the road impacts resulting from the use by project vehicles would be mitigated.

Outreach

A communications and outreach plan was developed to familiarize key stakeholders with the proposed project, to solicit their input and guidance on key siting and environmental issues, and to garner their support. The original focus of this plan was to help stakeholders understand the context of PG&E's land acquisition, geotechnical survey, and reservoir feasibility testing activities; to engage stakeholders positively; and to remind them of PG&E's interest in potential energy storage development to facilitate significant future additions of intermittent renewables.

To identify key stakeholders and track outreach efforts, an outreach contact list was developed and utilized for each of the short-listed sites. For each site, the contact list included: stakeholder name, contact, PG&E employee with point of contact responsibility, and a contact record. Stakeholders, in general, were representative of the following interests:

- Federal entities (regulators, elected officials)
- State entities
- Local entities
- Environmental groups with broader interests
- Industry groups
- Other groups and entities with interest in areas we may be considering
- Landowners (with and without which we have site control agreements in place)
- Customers/other community groups
- Media
- PG&E employees
- Shareholders/Investment community

Implementation of the communication plan was conducted once the site was confirmed for drilling activity and the applicable permits had been secured. The primary messaging included:

- Site Selection/Construction: Sites had been selected, and construction activities would begin shortly.
- Scope of Work: For this phase, a temporary core well will be drilled, and a geotechnical sample will be taken and analyzed in the lab.
- Timing: Timing was provided for site preparation and core drilling activities (as forecast at the time).
- Activity: Effects could include increased truck and worker transport traffic, and potential noise from traffic and drill rig.

AMMs and Mitigation Measures

A number of Avoidance and Minimization Measures (AMMs) and Mitigation Measures were implemented during core-drilling operations. Due to the location of the sites in the Central Valley ecoregion, resource issues were fairly homogeneous, so these measures applied to all locations. Further, most measures are standard PG&E best management practices for construction activities. The measures are described in: Appendix 5A, Attachment 1, AMMs and Mitigation Measures.docx

5.4 CONSTRUCTION SERVICES

5.4.1 Site Preparation

Each site was remote, was made up of active agricultural orchard, had a history of natural gas production, and had an existing well pad. To accomplish drilling activities for core removal, PG&E estimated that one acre of space would be required. The existing well pad could be utilized, thus slightly reducing the impact of the site preparation activities.

The first step for the core-drilling operations was preparing the site and improving existing access roads. In general, this work included surveying and delineating the work areas, clearing the pertinent areas of organic matter, excavating to an engineered depth, and backfilling, compacting, and grading with engineered aggregate.

The access roads were compacted, aggregate farm roads that were prepared for the facility construction and operations. Parking was generally very limited at the facility, and preparations were made to shuttle workers in if it was required. The facility pad was surfaced with aggregate. No asphalt was used for roads or parking.

In addition to the access road work improvements, an aggregate equipment pad was required at the site. As mentioned, each site already had a pad utilized for existing, operating natural gas well. These wells required protection during construction and drilling of the core well. This was required by constructing a temporary barrier around the equipment to visually and physically separate the equipment from construction traffic. In addition to the scope of work associated with the access roads, the general scope of supply for the site contractor included clearing of the existing orchard for the expansion of the well pad, setting and maintaining of Storm Water Pollution Prevention Program (SWPPP) measures, drill pad construction, and dust control.

To expand the existing well pad, the site needed to be cleared of orchard trees, shrubs, and vegetation to the extent necessary to accomplish clearing, excavation, backfill, and grading as required and achieve the finished site grades required for drilling.

Figure 5-1. Clearing and Grubbing (Removal of Organic Matter) of King Island Site

Excavation work for the location build consisted of the removal of earth, sand, gravel, vegetation, organic matter, rock, boulders, and debris to the lines and grades necessary for construction (Figure 5-1). Materials suitable for backfill were stockpiled at designated laydown locations using proper erosion protection methods.

Figure 5-2. Placement of Subgrade, Geotech Fabric, and Initial Compaction

Backfilling was done in uniform layers of specified thickness (Figure 5-2). Soil in each layer was properly moistened to obtain its specified density. To verify compaction, PG&E conducted representative field density and moisture-content tests during compaction.

Figure 5-3. Aggregate Placed for Well Pad; Compaction Ongoing

Site final **grading** design complied with applicable land development regulations (Figure 5-3). Graded areas were smooth, compacted, free from irregular surface changes, and sloped to drain away from equipment anchorages as necessary to maintain proper drainage (Figures 5-3 and 5-4).

Figure 5-4. Aggregate Base Installed and Preliminary Compaction Achieved; Proof-rolling of Site Continues to Ensure Proper Compaction and Grading

During construction, PG&E implemented erosion and sediment control measures. A basic erosion and sediment control plan was used during the location build phase of the project. The plan included the incorporation of silt fencing, straw bale dikes, storm inlet protection, swales, piping, and other routine measures.

5.4.2 Drilling

The core drilling construction effort required multiple site contracts (16 field contracts) and drilling specialty services. PG&E's attempts to "turn-key" the construction work (i.e., hire one contractor to handle all services and to subcontract as necessary with other contractors) were unsuccessful. It is uncommon in the drilling industry to "turn-key" this effort.

To manage the effort efficiently, PG&E grouped various functions into single contracts as indicated in Table 5-1.

Table 5-1 Core Drilling Construction Contracts

	WELL DRILLING AND ABANDONMENT
Contract #1	Drilling crew and rig
	Short-haul trucking
	Potable water
	Trash bin rental and service
	Fork lift rental
	Frac tank rental
	Fuel
	Welding
	Portable toilets
	DRILLING SITE SUPPORT SERVICES
#2	Drill bit and bottom hole assembly
	Down-hole equipment rental
#3	Electric logging
	Mud, fluids, nitrogen, coil tubing
	Directional drilling
	Cementing
#4	Under-reaming
	Liner assembly
	Gravel packing
	Free point service
	Fishing service
#5	Casing tongs service
#6	Mud logging
	LOCATION BUILDING RFP
#7	Location building (incl. access road, site prep,

	rathole, mousehole, conductor casing)
#8	Rathole, mousehole, cellar, and conductor
	SITE SERVICES, MATERIALS & EQUIPMENT
#9	Trailer rental
#10	Mud-cleaning equipment
	Generator rental (for trailer and mud cleaner)
#11	Vacuum trucks
	Mud and cuttings disposal
	Water supply
#12	Mud pit and mud tank cleaning
	Rig and tank cleaning
#13	Casing/tubulars (incl. long-haul transport trucking)
#14	Wellhead and downhole pressure/temperature (P/T) gauges and installation
	OFF-SITE SERVICES
#15	Sidewall core preservation, shipping, and core analysis

The following descriptions of some of the services may help when reviewing Table 5-1.

Cellar, Rathole, Mousehole, and Conductor

- The cellar is an excavation 8 ft x 8 ft x 5 ft deep. It provides a pit in the ground to provide additional height between the rig floor and the well head to accommodate the installation of blowout preventers, ratholes, and mouseholes. It also collects drainage water and other fluids for disposal (Figure 5-5).

Figure 5-5. Cellar Installed (8 ft x 8 ft x 5 ft)

- The rathole and mousehole are the dimensions dictated by the drill rig. They are shallow bores under the drill rig floor, usually lined with pipe, in which joints of drill pipe are temporarily suspended for later connection to the drill string.
- The conductor is a 20-in. diameter pipe installed to a depth of 60 ft. This pipe is the largest diameter casing and the topmost length of casing. It is relatively short and encases the topmost string of casing (Figure 5-6).

Figure 5-6. Conductor and Mousehole after Installation

Casing/Tubulars

- Total Depth: ~ 5000 ft.
- Surface Casing: 600 ft of 9-5/8 in. pipe. This casing is usually the first casing to be run in a well. It is installed early on so that a blowout preventer can be installed before drilling is started.
- Long String Casing: ~5000 ft of 5-1/2 in. pipe.

Tongs

Tongs are the large wrenches used for turning when making up or breaking out drill pipe, casing, tubing, or other pipe. They are variously called casing tongs, rotary tongs, and so forth according to the specific use. Power tongs are pneumatically or hydraulically operated tools that spin the pipe up and, in some instances, apply the final makeup torque.

Mud Supplier

The "mud" is the drilling fluid. It is engineered to inject while drilling and helps prevent pressure release of the well. The blowout preventer is an additional level of protection for preventing the rapid uncontrolled discharge of well pressure.

Mud Pit

Mud pits are a series of open tanks, usually made of steel plates, through which the drilling mud is cycled to allow sand and sediments to settle out. Additives are mixed with the mud in the pit, and the fluid is temporarily stored there before being pumped back into the well. Mud pit compartments are also called shaker pits, settling pits, and suction pits, depending on their main purpose.

Drill Bits and BHA

These components refer to the drill bits utilized in the well-drilling operations. The bottom hole assembly (BHA), which is a component of the drilling rig, is the lower part of the drill string, extending from the bit to the drill pipe. The assembly can consist of drill collars, sub-assemblies such as stabilizers, reamers, shocks, hole-openers, and the bit.

5.4.3 Site Management – The Company Man

Overall management of the site/drilling effort as well as for these specialty services was performed by the "Company Man." The Company Man, a hired position, coordinates the various activities at the site among the various contractors supporting the drilling effort, while ensuring that the resources are efficiently utilized to complete the drilling program objectives. Based on the progress of the drilling operation, the Company Man calls in resources to make sure they are available and/or release resources when they are no longer needed to meet the drilling plan goals (Figure 5-7).

The Company Man role is critical for drilling operations. This individual manages not only the 24-hour-per-day operation, but also the resolution of technical issues in real time. For instance, when the drilling depth per day was not meeting expectations, the Company Man coordinated a drill bit change, which allowed the drilling operation depth rate to come back in line with expectations.

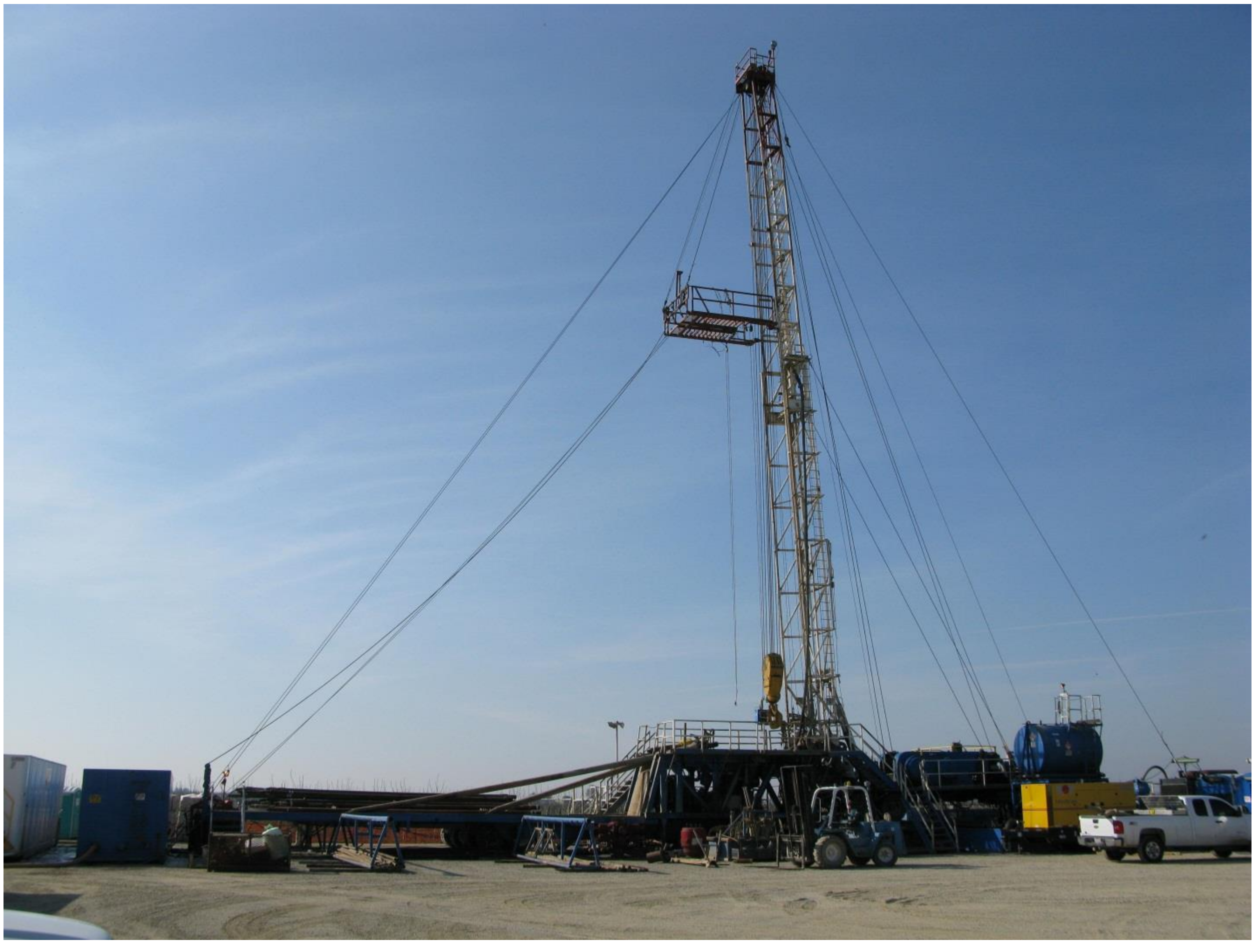


Figure 5-7. Drill Rig after Mobilization

The Company Man manages the reconciliation of field tickets (daily invoicing) from each specialty drilling contractor, a critical task given the flurry of activity that can occur at a drill site. This role is critical from a management of budget standpoint because many of the specialty contractors are compensated based upon daily rates.

5.4.4 Site Safety

The site required a comprehensive site-specific safety plan. The following key components were included in the plan:

1. The contractors were required to incorporate into this plan comprehensive method statements for all major construction activities.
2. The contractors were required to ensure that all workers were properly informed, consulted, and trained on health and safety issues in accordance with the approved site safety plan, as well as all relevant local and national regulations. This training included worker training with identification of the locations of the nearest care facilities.

3. The contractors maintained up-to-date file Material Safety Data Sheets (MSDS) for all hazardous materials on site and under the control of the Contractor in accordance with state and federal rules and regulations.
4. The contractors were required to assign a full-time site safety manager to the project for the duration of site work activities.

5.5 CORING PROGRAM

5.5.1 Coring Method – Conventional vs. Continuous

Two types of coring technology were evaluated for use on the CAES project: conventional and continuous. Conventional coring is typically done in 30-ft increments, the length of each core barrel. The core barrel must be retrieved by tripping out of the well after each 30-ft segment has been cored. Continuous coring utilizes a wireline system to retrieve the core so that tripping out of the hole with the coring tools is not necessary for each core recovery once the coring operation has started.

Conventional coring services are less expensive than continuous coring (estimated at $112K vs. $203K for the King Island well). However, they require more rig time to acquire the core, so the overall net cost for conventional coring is actually somewhat higher ($332K vs. $203K). The key advantages of conventional coring are: 1) it has better success in retrieving the core in unconsolidated formations due to the core-catcher design, and 2) the core diameter is somewhat larger (4 in. vs. 3.5 in.), which provides more uninvaded core and larger core plugs for laboratory analysis. The key advantages of continuous coring are: 1) lower overall cost, 2) a somewhat lower drilling risk due to being able to maintain circulation while retrieving the core, and 3) less time working in the open hole.

The project team interviewed one vendor for each type of coring service. Based on those interviews and the team's analysis of both coring technologies, the overall cost comparison, the potential risk of core recovery, and the potential impact on the project schedule, the team selected conventional coring.

5.5.2 Amount of Core to Extract

To achieve all of the stated objectives, the project team needed to decide how much core should be acquired at each site. Preliminary plans were to have the basic properties (porosity, permeability, and water saturation) tested on one core plug extracted from the core every foot. More detailed tests would be conducted on a fewer number of select samples as identified by an experienced geologist. Three distinct intervals were discussed for coring:

- Caprock immediately above the reservoir formation
- Productive interval of the reservoir (above the gas-water contact)
- Reservoir formation immediately below the gas-water contact

By identifying each of these three intervals, the project team could conduct the coring operation continuously once started, avoiding the need to switch back and forth with drilling operations and saving considerably on rig time and costs. The team decided on a minimum of 30 ft of caprock core to ensure the recovery of competent rock with good sealing characteristics for the reasons discussed above. The productive interval is defined by the well log data and can vary significantly from site to site. The interval below the gas-water contact can be important to determine if any deeper barriers to vertical communication exist. The team decided on a minimum of 30 ft for this interval. Based on these general parameters and the proposed location for the core well, geological interpretations for each potential site were analyzed to determine the approximate coring interval (see Appendix 5A, Attachment 2, CAES CoreRecom—East and King.pdf). These intervals were preliminary, as determined from the information available and could be adjusted onsite based on the mud log correlations during drilling operations.

5.5.3 Selection of the Sites for Coring

Based on a variety of factors that were considered before making the final selection (see Chapters 3 and 4), two reservoirs emerged as the top candidates for coring and additional testing: King Island and East Islands. In parallel with the process of evaluating each of these two reservoirs for their development potential, basic coring and logging programs were developed for each of the candidate reservoirs (see Appendix 5A, Attachment 24, Summary logging and coring program 2Fields ACTUAL.xls). Core well drilling technical specifications were compiled for the two reservoirs. At the King Island reservoir and the East Islands reservoirs, one core well was drilled at each site.

At King Island, the Piacentine #2-27 well was designed as a straight hole, located approximately 150 ft south and slightly west of the Piacentine #1-27 producing well (see Appendix 5A, Attachment 13, King Island Map). Based on the geological interpretation, this location appeared to be in a good structural location in the eastern lobe of the reservoir.

At East Islands, the Morais # 16-2 well was planned as a directional well, designed to intersect the top of the reservoir approximately 450 ft north and 210 ft west of the existing Morais #16-1 well location (see Appendix 5A, Attachment 8, East Island Map). This location was near the reservoir's structural high, based on seismic review and the then current geologic model.

5.5.4 Drilling, Coring, Testing, and Completion Programs

Detailed drilling and logging programs were prepared for King Island and East Islands (see Appendix 5A, Attachment 21, Piacentine 2-27 Drilling Program.docm; and Appendix 5A, Attachment 10, East Islands Drilling Program.docx). Both programs were essentially the same, utilizing a 9-5/8-in. surface casing set to approximately 600 ft and then drilling an 8-1/2-in. hole to the start of the coring interval (Figure 5-8). The selected interval was cored with conventional coring tools, retrieving a 4-in. diameter core. Core recovery was excellent. At King Island, the Piacentine #2-27 well recovered about 171 feet of core. At East Islands, the Morais #16-2 well recovered about 116 feet of core. The actual results of the coring operation are included in the MHA Reservoir Characterization and Analysis of Suitability for CAES Storage for both reservoirs (see Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf; and Appendix 5A, Attachment 6, East Island, Reservoir Characterization and Analysis of Suitability for CAES.pdf).

Figure 5-8. Core Barrel after Extraction from Approximately 4,700 feet

After completion of the coring operation, the 8-1/2-in. hole was drilled to total depth (TD), logged, downhole tested at selected depths, and sidewall percussion cores were retrieved. The well was then cased with 5-1/2-in. casing from TD to surface for later use potentially as an observation well. A cement bond log was run to ensure proper bond, and good sealing properties were achieved for the casing.

Part of the sidewall coring procedure included the collection of pressure data, under limited flow conditions, which was interpreted for permeability. Downhole pressure transient tests were completed on both wells (see Appendix 5A, Attachment 23, PIACENTINE 2-27 RDT Survey Pressures.doc; and Appendix 5A, Attachment 16, MORIAS 16-2 RDT Transient Pressures.pdf). At King Island, at the Piacentine #2-27 well, 13 tests were completed. At East Islands, at the Morais # 16-2 well, 12 tests were run successfully. Analysis of the results provides an estimate of reservoir permeability, which can be compared to the laboratory results from the coring operation. At the conclusion of the pressure testing, one reservoir water sample was acquired from below the gas-water contact at the King Island Piacentine #2-27 well and analyzed in the laboratory. Those results are included as Appendix 5A, Attachment 11, EM513082PG Piacentine 2-27 Geochem Final 4-29-13.pdf.

The core was recovered in the field by service personnel. The aluminum core liner was cut into 3-ft lengths and transported to CoreLab Bakersfield. At the lab the core was slabbed longitudinally into one-third and two-third segments, photographed, described in detail by an experienced geologist (see Appendix 5A, Attachment 5, CoreSummary Piacentine 2-27 rev 26 June 2013 final.docx; and Appendix 5A, Attachment 4, Core Description Morais 2-16-20 Apr 2013.pdf) (Figure 5-9). The core also underwent core spectral gamma and computerized tomography (CT) scanning.

5.5.5 Well Logging Program and Results

During drilling of the King Island Piacentine #2-27 core well in March 2013 and the East Islands Morais #16-2 core well in April 2013, Halliburton conducted a comprehensive wireline open-hole logging program, which included porosity logs in the target injection zones. In addition, for the King Island field, the project team had access to well logs acquired by Schlumberger during drilling of the Citizen Green 1 well in December 2011. The logs and information obtained during the core well logging programs are summarized in Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf; and Appendix 5A, Attachment 6, East Island, Reservoir Characterization and Analysis of Suitability for CAES.pdf. Copies of most of the logs for the Citizen Green 1 (with exception of the nuclear magnetic resonance log and sonic log) are available at the DOGGR online data site.

Digital Formation, a petrophysical consulting company located in Denver, Colorado, analyzed and interpreted the geophysical logs for the Piacentine #2-27 and Citizen Green 1 wells. The Digital Formation report is provided in Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf, and includes the analytical methodology, formulas, and rock property results, as well as composite interpretation logs, for the Piacentine #2-27 core well and Citizen Green 1 well.

Appendix 5A, Attachment 22, Piacentine 2-27 Well Summary Report.pdf and Appendix 5A, Attachment 17, Morais 16-2 Well Summary Report, 4-15-2013.pdf were submitted to DOGGR after drilling and completion of the Piacentine #2-27 and Morais #16-2 wells.

5.5.6 Core Laboratory Analysis and Results

The subsurface project team worked closely with CoreLab to determine the appropriate laboratory tests to complete on each core. Both “routine” and “advanced” tests were included in the final testing program (Appendix 5A, Attachment 3, Core Analysis Requirements.xls). Routine tests included measurement of such characteristics as matrix and bulk density, porosity, permeability (both horizontal and vertical), and sieve analysis. All analyses were performed on samples taken from every foot of core, except vertical permeability and sieve, which were only measured on selected samples.

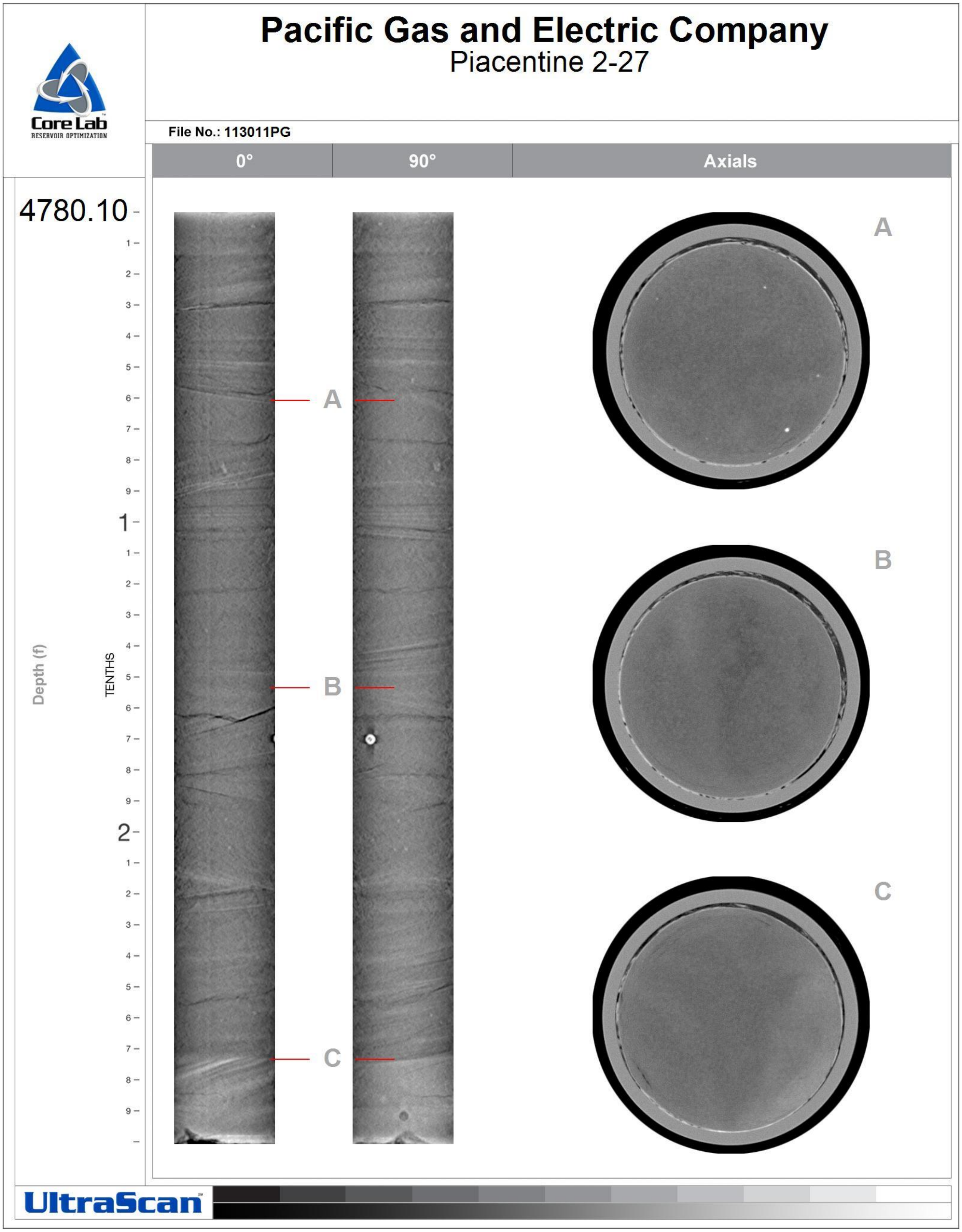


Figure 5-9. Photographed Section of King Island Core from Depth of Approximately 4,780 feet

Advanced analyses included such items as x-ray diffraction, capillary pressure, relative permeability, and permeability/porosity after stress cycling. A complete list of the type of analyses, the purpose of each, and the test procedures is included in Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf; and Appendix 5A, Attachment 6, East Island, Reservoir Characterization and Analysis of Suitability for CAES.pdf.

King Island Core Results

Based on the results from the laboratory testing at CoreLab Bakersfield, the horizontal permeability of the Mokelumne River Formation, the storage zone, appears to be excellent, ranging from 153 mD to 19,087 mD, and averaging 807 mD. Vertical permeabilities range from 278 to 17,855 mD.

Test results for the caprock also proved to be favorable. Based on two separate approaches, the vertical permeabilities were measured at 0.04 and 0.06 mD, indicating good sealing characteristics for a potential storage reservoir. Similarly, the threshold pressure test results on three samples were excellent, as indicated by no gas breakthough at a maximum delta pressure across the core samples of 2,000 psi.

Core samples were subjected to a pressurized air chamber test to investigate the potential interaction between injected air and the reservoir rock at King Island. The results indicate good suitability for a CAES development in the reservoir with little reaction expected between the injected air and the reservoir rock. Details of the testing procedures and results are included in Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf; and Appendix 5A, Attachment 6, East Island, Reservoir Characterization and Analysis of Suitability for CAES.pdf.

A bottomhole reservoir water sample was obtained from the Piacentine #2-27 well using Halliburton's Reservoir Description Tool. The total dissolved solids for the sample were 14,000 ppm, and the total sodium chloride was 13,000 ppm. Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf includes more detail on the fluid properties.

East Island Core Results

Based on the results from the laboratory testing at CoreLab Bakersfield, the horizontal permeability of the Meganos Channel Sands, the storage zone, appears to be excellent. At a confining pressure of 2,700 psi, the horizontal permeabilities on 77 samples averaged 1,464 mD, with porosity averaging 34.5%. Vertical permeabilities were similarly very high, with 15 samples tested for the Meganos Channel Morais sand ranging from 329 to 13,195 mD, and the average (arithmetic) vertical–to-horizontal permeability anisotropy ratio is 1.006.

The horizontal permeability of the caprock zone, the Capay Shale, was measured from conventional core samples. The harmonic mean of eight horizontal ambient stress (250 psi) permeability measurements in the Capay Shale, corrected to 2,700 psi confining stress, was 0.09 md. Even at this low permeability (0.09 mD), based on this limited set of core data, the Capay Shale may not be considered an impermeable barrier, and additional testing is recommended.

5.6 RESERVOIR MODELING AND RESULTS

MHA Petroleum Consultants (Denver) developed detailed static and reservoir models for both the King Island and East Islands gas fields, as described in Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf; and Appendix 5A, Attachment 6, East Island, Reservoir Characterization and Analysis of Suitability for CAES.pdf. The models were created to help design the bubble development program, predict air/water displacement, and estimate reservoir pressure levels for a given air bubble design volume. Simulations were completed of both a compression testing program and a full field development scenario.

5.6.1 King Island Modeling

A three-dimensional geological (static) model was developed for the productive Mokelumne River formation at King Island, utilizing a variety of data including geological reports, maps, cross-sections through the reservoir, and digitized well log and seismic amplitude data. The model was constructed with the aid of Schlumberger Petrel software (2012.4). The resulting reservoir covered 213 acres and had an estimated original gas-in-place of 14.9 Bscf. Details of the process to construct the model and results are included in Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf.

A dynamic simulation model was created from the static model to match the reservoir performance and simulate the process of air injection into the reservoir for CAES testing and full-field development scenarios. Simulations in this study were performed using the ECLIPSE commercial numerical simulator, a Schlumberger software product. ECLIPSE is a three-dimensional (3-D) finite-difference black-oil simulator used for modelling oil and natural gas hydrocarbon systems.

To make the model as realistic as possible, it was calibrated (history-matched) to the historical production and reservoir pressure performance for the three producing gas wells in the field. The history matching process not only helps tune the model for more accurate simulations, but also seeks to establish as best as possible the current reservoir conditions of gas/water saturation and pressure distributions prior to the start of the compression testing program. As a result of the history matching process, the original gas-in-place volume was adjusted downwards slightly to 13.79 Bscf.

A compression test, involving the injection of 0.5 Bcf of oxygen-depleted air followed by a series of withdrawal tests, was planned for King Island. The model was used to predict the reservoir performance during the compression test, including the air/native gas mixture being produced to the surface so that a decision could be made as to the feasibility of safely testing with ambient air.

Results of the compression test modeling indicate that a bubble size of 0.5 Bcf appears to be sufficient to conduct the testing program as designed. Native gas concentrations are not expected to exceed 0.8% during withdrawal. Gas concentrations increase as the air bubble is depleted. Water production during testing is expected to be limited to approximately 450 Bbl total.

The model was also utilized to simulate the operating characteristics of the reservoir in a full-field development scenario supporting a 300-MW surface facility. The results of these simulations are included in Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf.

5.6.2 East Islands Modeling

Modeling of the East Islands site produced the following results. Full-field development for a CAES facility of up to 150-MW design can be supported based on peak withdrawals of 550 MMcfd for up to 10 hours. An initial air bubble size of 3.6 Bcf is sufficient to sustain operations based on a 10-hour withdrawal cycle. A total of 14 injection/withdrawal wells are required. A maximum reservoir pressure of 3,000 psi is assumed. The maximum methane concentration will be 2.3% after six weekly cycles. Individual wells show methane concentrations up to 5%, but the model has not yet been optimized to control methane.

5.7 SUMMARY

Based on data available from public sources and the screening process, the project team selected two sites, King Island and East Islands, which were judged to have the best potential for CAES development.

The primary objective for drilling a core well and evaluating the cores was to refine the reservoir analyses through the acquisition of high-quality data so that the site with the greatest likelihood of achieving a successful CAES development could be confidently selected. Specific objectives included: improving the geological database, analyzing reservoir rock properties, determining caprock properties, conducting reservoir pressure tests, obtaining reservoir fluid samples, and determining the design and location for observation purposes during testing.

Prior to conducting any site work, PG&E acquired the necessary federal, state, and local permits and/or regulatory authorities to conduct the envisioned work. Outreach was also conducted to familiarize key stakeholders with the proposed project, to solicit their input and guidance on key siting and environmental issues, and to garner their support.

The first step for the core-drilling operations was preparing the site and improving existing access roads. In general, this work included surveying and delineating the work areas, clearing the pertinent areas of organic matter, excavating to an engineered depth, and backfilling, compacting, and grading with engineered aggregate.

The core drilling construction effort required multiple site contracts (16 field contracts) and drilling specialty services.

The project team selected conventional coring technologies. The team decided on a minimum of 30 ft of caprock core. One core well was drilled at each of the two sites. At King Island, a well was drilled at the Piacentine #2-27 well. At East Islands, a well was drilled at the Morais #16-2 well. Detailed drilling and logging programs were prepared for the two sites. Once obtained, the core samples were subjected to laboratory tests and analyses.

Based on test results, the horizontal, vertical, and caprock permeability of the King Island well were found to be favorable. At the East Islands well, the horizontal and vertical permeability were found to be excellent; the Capay Shale may not be considered an impermeable barrier, and additional testing is recommended.

Appendices

Appendix 5A, Attachment 1, AMMs and Mitigation Measures.docx
Appendix 5A, Attachment 2, CAES CoreRecom—East and King.pdf.
Appendix 5A, Attachment 3, Core Analysis Requirements.xls.
Appendix 5A, Attachment 4, Core Description Morais 2-16-20 Apr 2013.pdf.
Appendix 5A, Attachment 5, CoreSummary Piacentine 2-27 rev 26 June 2013 final.docx.
Appendix 5A, Attachment 6, East Island, Reservoir Characterization and Analysis of Suitability for CAES.pdf.
Appendix 5A, Attachment 7, East Island Cultural Final No Records.pdf.
Appendix 5A, Attachment 8, East Island Map.
Appendix 5A, Attachment 9, East Island BCA Final.pdf.
Appendix 5A, Attachment 10, East Islands Drilling Program.docx.
Appendix 5A, Attachment 11, EM513082PG Piacentine 2-27 Geochem Final 4-29-13.pdf.
Appendix 5A, Attachment 12, King Island Reservoir Characterization and Analysis of Suitability for CAES.pdf.
Appendix 5A, Attachment 13, King Island Map.
Appendix 5A, Attachment 14, King Island Cultural Final No Records.pdf.
Appendix 5A, Attachment 15, Kings Island BCA Final.pdf.
Appendix 5A, Attachment 16, MORIAS 16-2 RDT Transient Pressures.pdf.
Appendix 5A, Attachment 17, Morais 16-2 Well Summary Report, 4-15-2013.pdf.
Appendix 5A, Attachment 18, PG&E EQ Interim Action Memorandum King-East-Cache.pdf
Appendix 5A, Attachment 19, PGE MORAIS 16-2 612-0397.pdf.
Appendix 5A, Attachment 20, PGE PIACENTINE 2-27 612-0396.pdf
Appendix 5A, Attachment 21, Piacentine 2-27 Drilling Program.docm.
Appendix 5A, Attachment 22, Piacentine 2-27 Well Summary Report.pdf.
Appendix 5A, Attachment 23, PIACENTINE 2-27 RDT Survey Pressures.doc
Appendix 5A, Attachment 24, Summary logging and coring program 2Fields ACTUAL.xls.

Chapter 6
Air Injection Testing and Analysis

6.1 INTRODUCTION

The King Island Reservoir was selected for additional air injection testing based on the previous screening analysis, the subsequent results of the core well drilling program, and significant reservoir modeling, as detailed in Chapter 5. The air injection testing program provides data regarding how the reservoir responds to air injection, both in terms of flow dynamics as well as rock mechanics. A reservoir developed for a CAES project is expected to perform essentially the same as an underground natural gas storage reservoir, except for the effects of injected air on the reservoir. The air could change rock properties over time, which in turn could affect the reservoir's effectiveness in storing compressed air. A testing program, therefore, was needed to answer the questions that regulators, developers, operators, and potential financial participants may have in regards to the reservoir.

The air injection testing, conducted from February to June, 2015, built an air bubble of approximately of 500 million standard cubic feet (MMscf). A series of injection and withdrawal tests were conducted to mimic the expected operation of a fully developed project. The test results were then utilized to help forecast the operational and economic performance of the project.

Chapter 6 describes the objectives of injection testing; simulation modeling of reservoir pressure, water production, and natural gas production; the final compression testing plan; planning and design of the Temporary Site Facility (TSF); the HAZID study; the revised testing plan based on the HAZID study; the detailed compression testing plan; separate modeling of methane in the withdrawal stream; risk mitigation strategies; the decision matrix used to support decision to move ahead; procurement of the TSF; the Hazard and Operability (HAZOP) Study; permitting; construction and operation of the TSF; and results of the Air Injection Testing (AIT).

Chapter 7 focuses on the results of the air injection test and how those results were utilized to update the various development and operational models and verify the performance of a fully developed CAES facility.

6.2 INJECTION TESTING OBJECTIVES

Given the basic approach that the CAES project had pursued to this point—including screening, coring, modeling, testing, and analyzing the results, the project team realized that the testing phase would be very critical to the future development and success of CAES and the utilization of a depleted natural gas reservoir. To ensure that as much information as possible was gathered during the testing phase, the team adopted a detailed set of objectives, along with the corresponding boundary conditions and various considerations. This section outlines the objectives.

6.2.1 Primary Testing Objective

The primary testing objective was to reduce and minimize the technical and financial risk of full project development. To achieve this primary objective, the testing program was designed to facilitate the collection of sufficient data that could be analyzed and modeled to accomplish the following:

- Determine well flow characteristics from the injection and withdrawal testing such that it can be extrapolated to the ultimate well design. These characteristics include both deliverability as well as injectivity.
- Determine the ultimate stable air bubble size (Bcf) and pressure profile over the entire operating cycle.
- Determine the operating characteristics during the initial bubble development stage, which includes:
  - Initial injection pressures required to build the initial bubble.
  - Expected rate, duration and total volume of water production up to the time when stable withdrawal operations are achieved.
  - Rate of bubble development.
- Determine the short- and long-term impacts of water drive on normal operations once the stable air bubble has been developed.
- Determine what the expected profile of concentrations of native gas (residual natural gas) that will be produced during withdrawal operations.
- Determine the optimal spacing, placement, and required number of injection / withdrawal (I/W) wells (both horizontal and vertical) to achieve the desired withdrawal rates and pressures over the entire operating cycle.
- Determine the potential for in-situ oxidation reactions (i.e., between oxygen in the injected air and reservoir minerals) based on the reservoir core data and downhole conditions and their potential impact on the long-term operating capability of the facility (i.e., the ability of the power generation equipment to operate with oxygen-depleted air).

6.2.2 Secondary Testing Objective

The secondary testing objective was to confirm the anticipated performance of the proposed site so that additional analysis can be completed to determine the financial and operational feasibility of a CAES system project with a high degree of certainty.

6.3 TESTING PROGRAM

Based upon the testing objectives outlined, the project team developed a comprehensive air injection testing program to demonstrate the viability for future development of the King Island Gas Field for a full-scale CAES plant. The testing program, described in more detail in Section 7.8, was designed to build an air bubble of sufficient size and then to conduct a series of injection / withdrawal tests. The injection / withdrawal test results for one well would be extrapolated to all of the wells required to support the fully developed, 300-MW facility.

6.4 RESERVOIR MODELING

Modeling work was undertaken to determine key information during the test such as:

- Reservoir pressure
- Water production
- Natural gas production

As discussed on the following pages, the modeling effort was an iterative process that evolved over a period of time. As with any modeling effort, the results changed over time as additional information was gathered and refinements were made to the model.

6.4.1 Initial Dynamic Model

The initial King Island dynamic model was based on simple assumptions for reservoir properties, and was not calibrated with any production or test data. The model assumed uniform high permeability in both horizontal (1,000 millidarcies, md) and vertical (100 md) directions (see Figures 6-1 and 6-2). The model outputs did not match well with reservoir pressure and water production history. The model was used to estimate the percentage (%) of native natural gas in the cycled air volumes for the initial compression testing simulation runs and for the Temporary Site Facility (TSF) engineering and hazard review process. The model showed the percentage of native gas in the simulated withdrawal streams ranged from 4.1 to 7.2% (Figure 6-3) for compression testing cases with a large air bubble size (950 mmcf) and a high air injection rate (17 mmcfd).

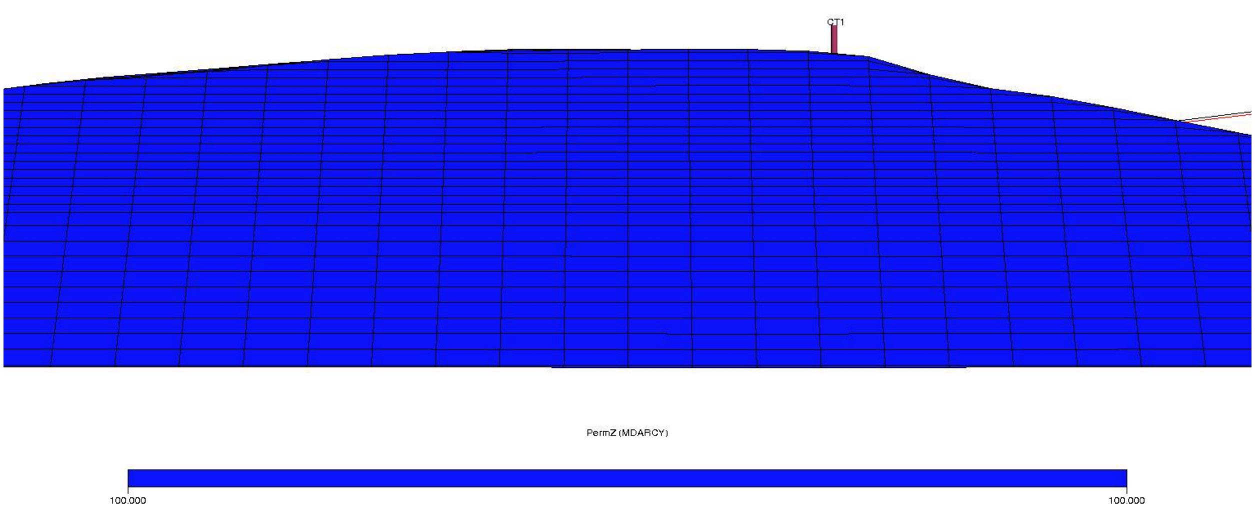


Figure 6-1 Initial King Island Dynamic Model: Permeability Z – Final Cycle Program 2 (Perm Z uniform – 100 mD)

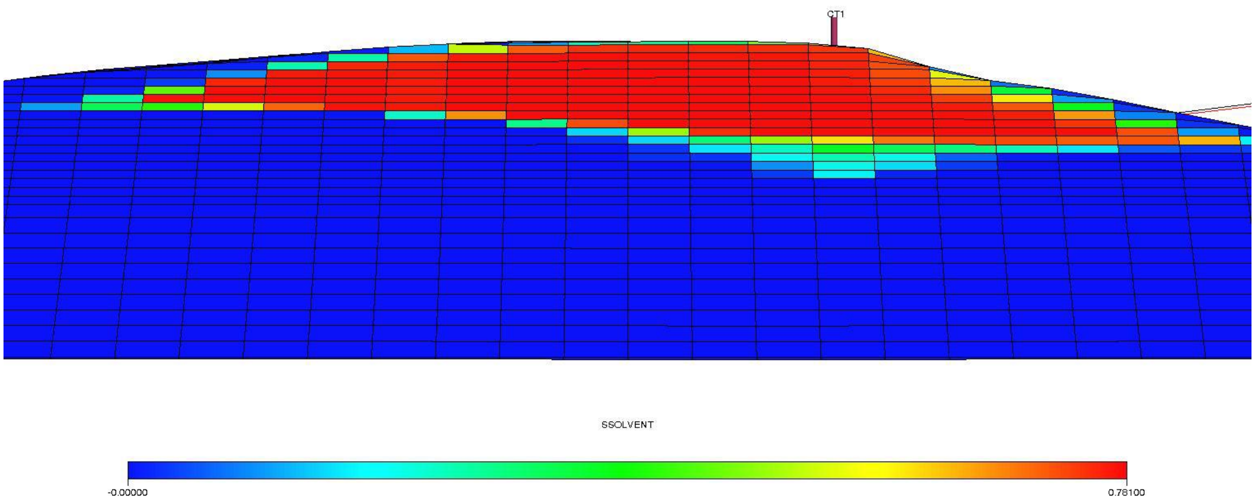


Figure 6-2 Early King Island Dynamic Model: Solvent Saturation—Final Cycle Program 2

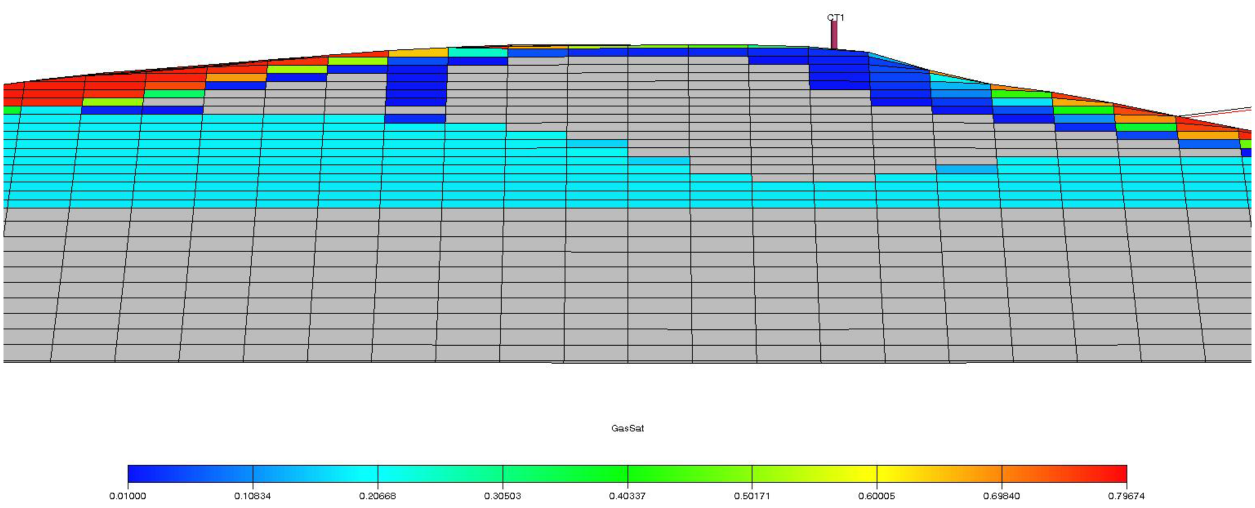


Figure 6-3 Early King Island Dynamic Model: Native Gas Saturation (Total native gas in withdrawal stream = 4.1 – 7.2%)

6.4.2 How the Model Changed

While the early model was used for the compression testing runs, the Project Consulting Engineer (PCE), through its subcontract with MHA Petroleum Consultants (Denver), continued its calibration changes to match the historical production and reservoir pressure performance data. The model was changed to incorporate variable horizontal permeability. Permeability was assumed to be a function of reservoir porosity, and it spanned the range of 1 md to 200 md (Figure 6-4). Vertical permeability was set at 0.1 times the horizontal permeability.

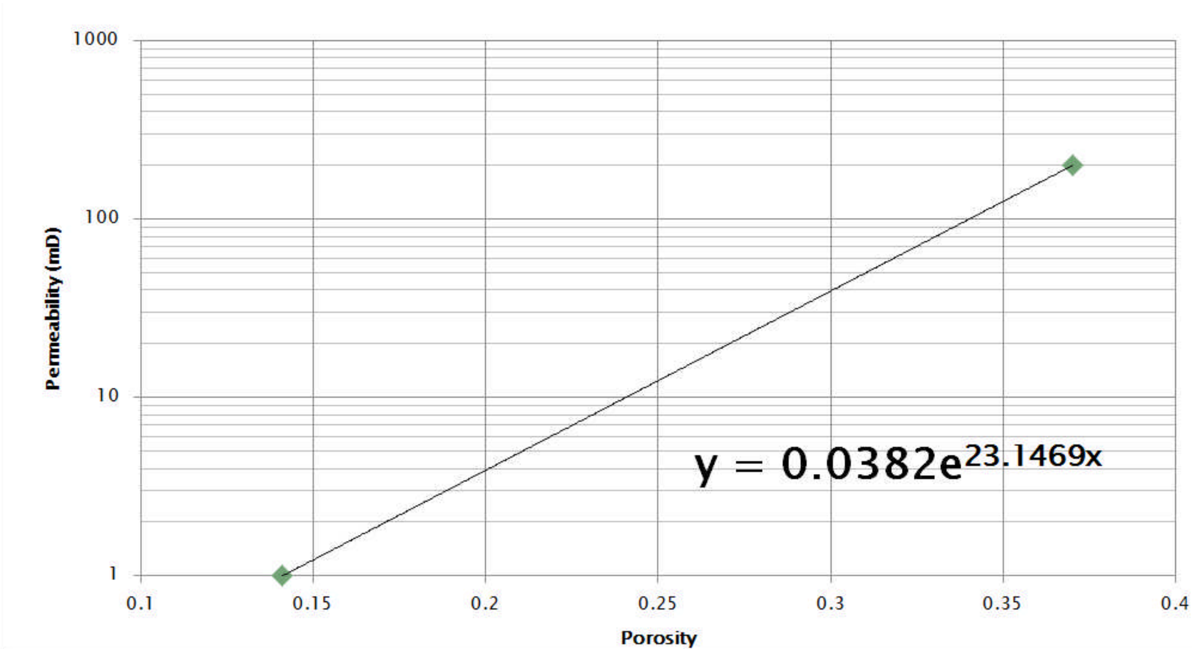


Figure 6-4 King Island Model: Variable Porosity-Permeability Correlation in X and Y Directions

In addition, the model was initialized with a J-function relationship, which sets initial water saturation (Swi) values as a function of porosity and permeability. The irreducible water saturation (Swirr) for a model cell with the highest permeability/porosity was set at 15% (Swirr – Swi). All other cells then have a Swirr value of greater than or equal to 15%. In the early model, the Swirr value was uniformly set at 22% for all cells.

Endpoint scaling was used in the gas-water relative permeability relationships. This scaling allowed for the use of a variable irreducible gas saturation (Sgr) distribution based on the porosity (Figure 6-5). Previously, the Sgr was a uniform 23% in the model.

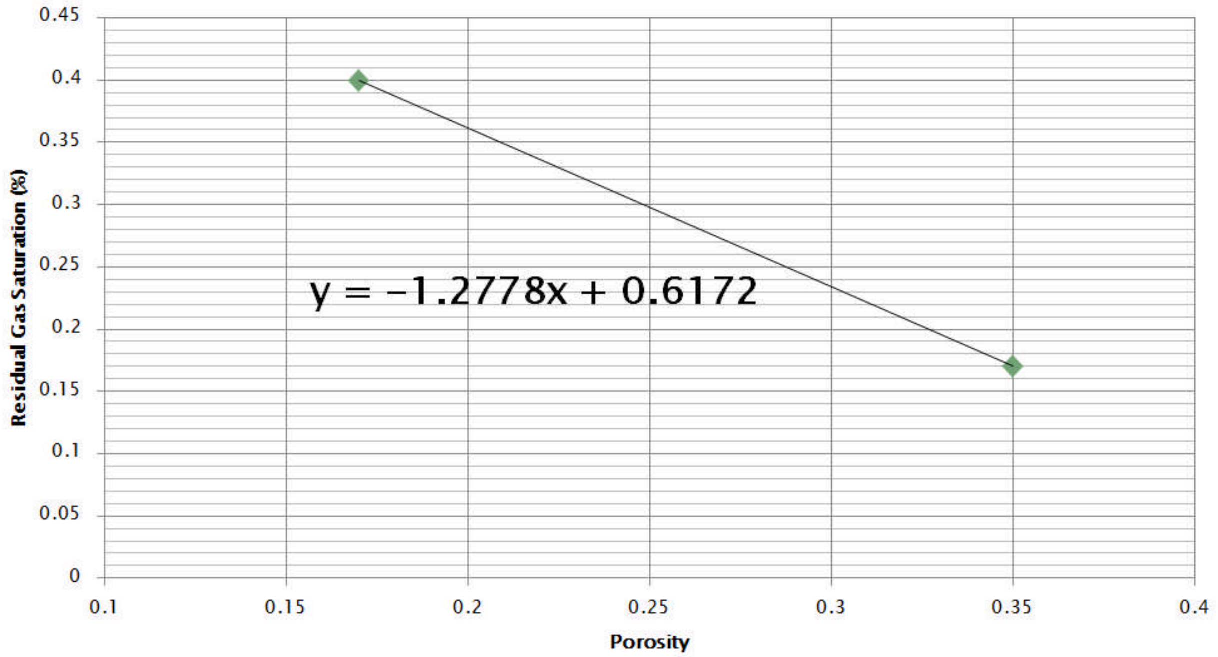


Figure 6-5 King Island Model: Porosity—Sgr Correlation

In the 1000 md early model, the water aquifer was a single aquifer attached to the west side of the model. In the updated history-matched model, there were two aquifers. These aquifers are both located on the east side of the model. The depth of the perforations in the model wells were corrected in the history-matched model based on adjustments to the reported Kelly Bushing (KB) levels (typically, well logs are measured with the zero mark at the KB elevation that is based on the surface elevation plus the height of the rig floor to achieve the KB height). As a result, perforations were generally lowered by about 10 feet in the current model relative to where they were in the early model. This correction helped to match the water production observed in the two main natural gas producing wells, Moresco 1 and Piacentine 1-27.

6.4.3 What the History-Matched Dynamic Model Showed

The calibrated model had a good history-match of the gas and water production from the King Island wells as well as a very good match of the reservoir pressure history and re-pressurization observed in the reported tubing pressures for all three wells including the Citizen Green. This history-matched model was then used to re-run the compression testing simulation cases conducted for the early model to re-investigate and validate the estimate of percentage native gas in the cycled air volumes from the early model.

The history-matched model (Figures 6-6 and 6-7) showed significantly less percentage native gas in the simulated withdrawal air streams than obtained for the early model simulations. The calibrated model showed a percentage native gas of less than 1% (Figure 6-8) of the produced air volumes for the same large air bubble size (950 mmcf) and high air injection rate (17 mmcfd).

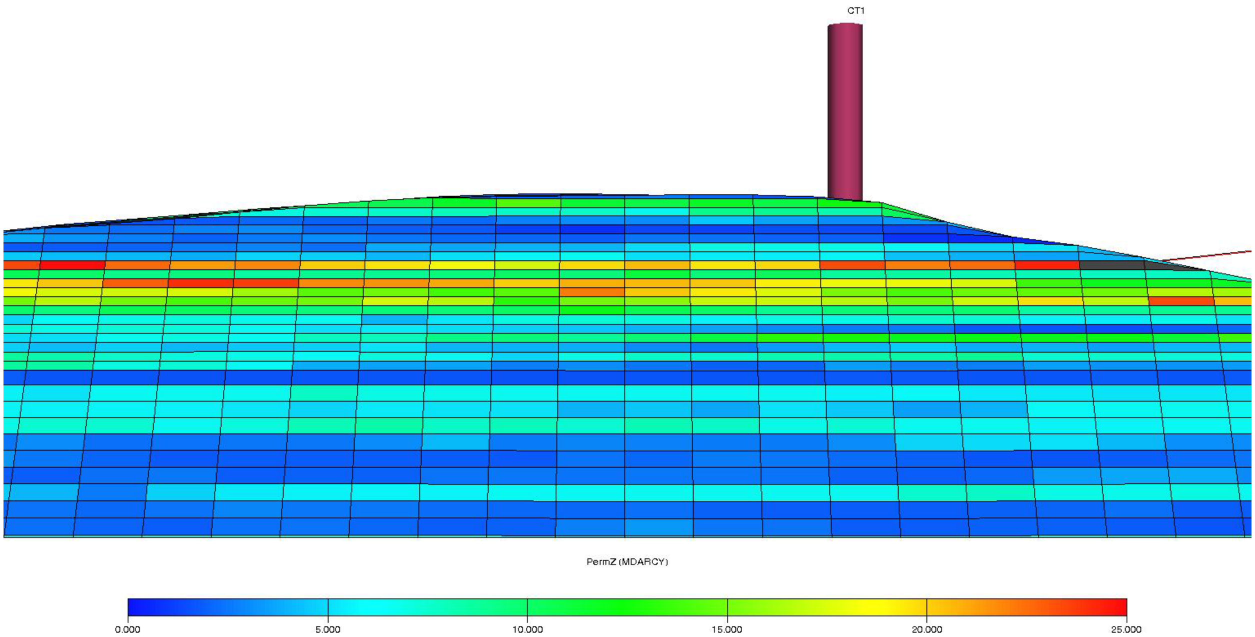


Figure 6-6 Updated King Island Dynamic Model: Permeability Z, Final Cycle Program 2 (Perm Z ranges from < 1mD to 25 mD)

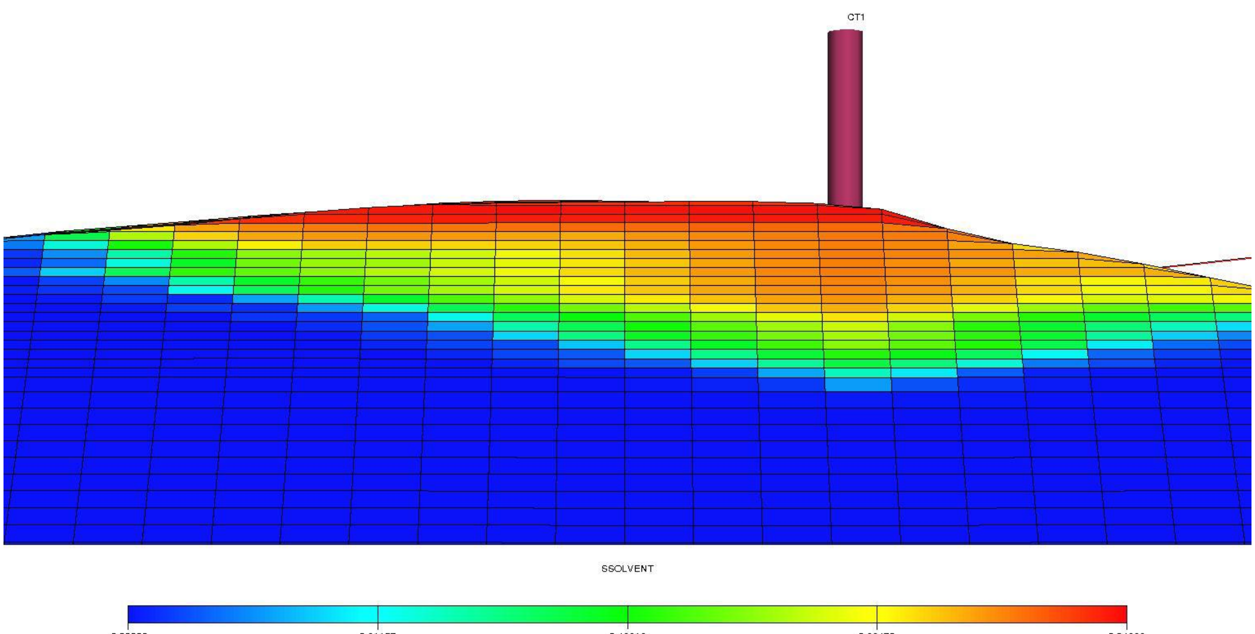


Figure 6-7 Updated King Island Dynamic Model: Solvent Saturation—Final Cycle Program 2 (Perm Z ranges from < 1mD to 25 mD)

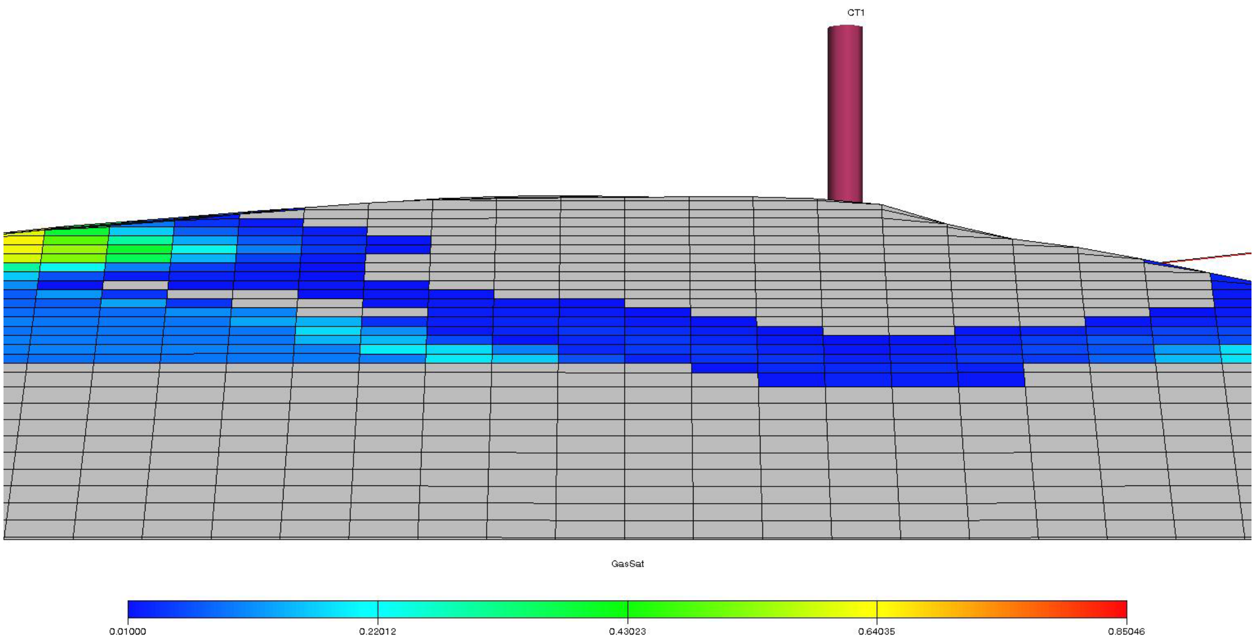


Figure 6-8 Updated King Island Dynamic Model: Native Gas Saturation—Final Cycle Program 2 (Total native gas in withdrawal stream < 0.2%)

Figure 6-9 shows the compression testing program based on an initial bubble size of 950 MMcf; the figure encompasses the bubble building effort through the various injection / withdrawal tests, based on the history-matched model, as envisioned at the time.

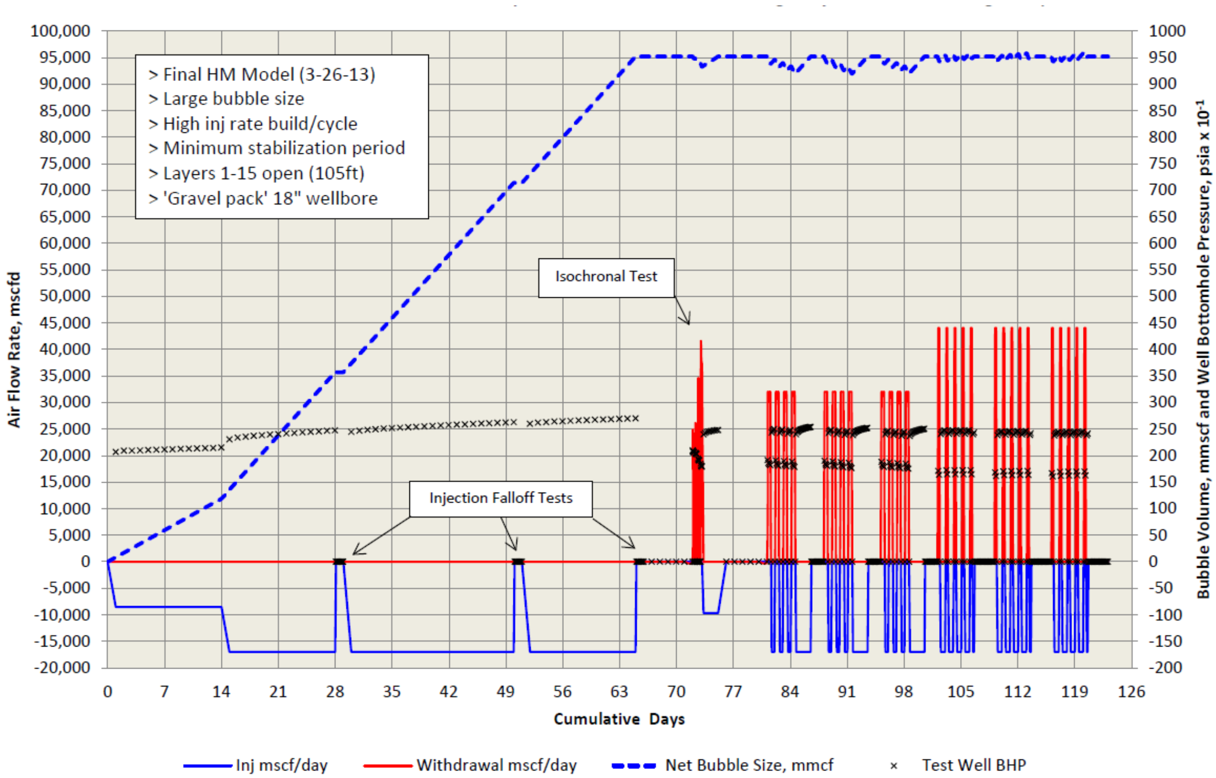


Figure 6-9 King Island Draft Compression Testing Program Model: Eclipse (March 2013). Bubble Size: 950 MMcf; 7.5% PV; 15d SI; Cycle Volume = 1.5% Bubble Size; Target Inj Rate = 17 mmcfd; gravel pack

Figure 6-10 focuses on the withdrawal portion of the test and shows, as referenced in Section 6.4.3, that the modeled native gas concentrations of less than 1%, are significantly lower than the initial results that utilized the early dynamic simulation model discussed in Section 6.4.1. These results were promising in that the model predicted the percentage of natural gas in the withdrawal stream would be lower than the Lower Explosive Limit (LEL).

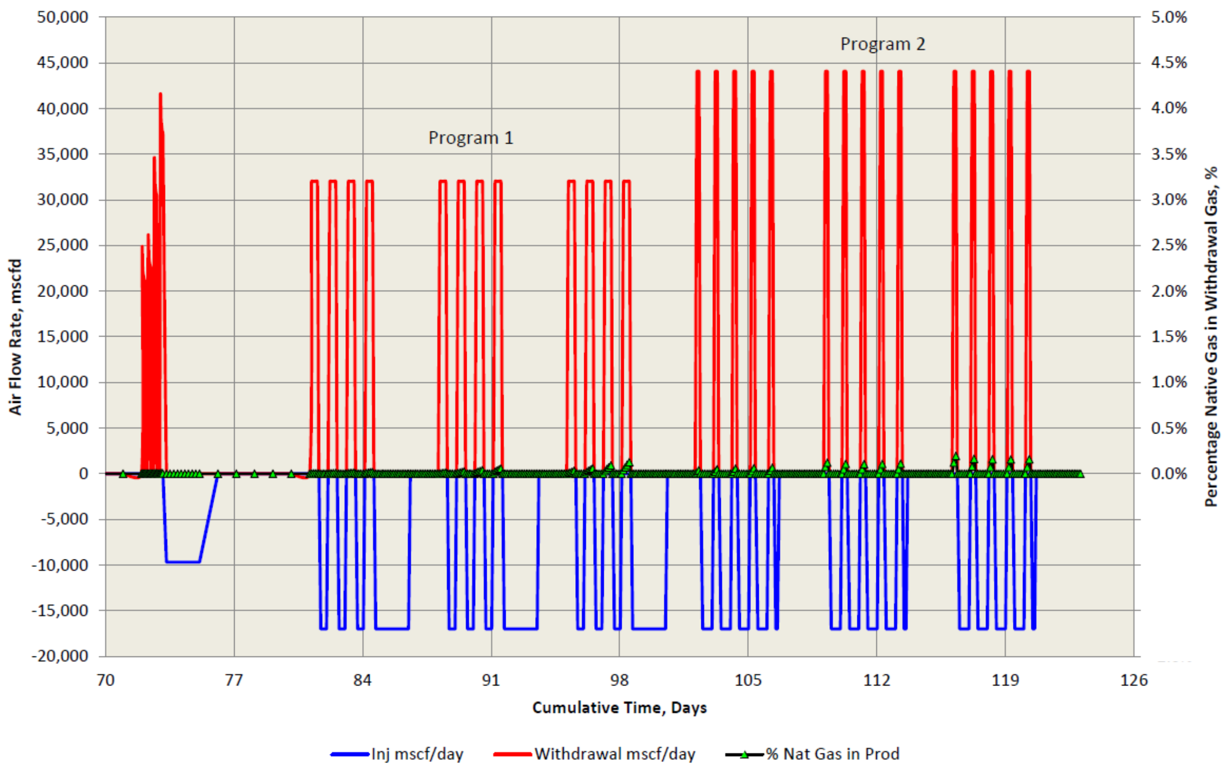


Figure 6-10 King Island Draft Compression Testing Program Model - March 2013 Cycle Testing Post Bubble Build (InjLayers 1-15) Program 1 (21 days): 32 mmcfd withdrawal x 10 hr, 2 hr SI, 17 mmcfd inj x 10 hr, 2 hr SI; Repeat 4 days; Repressure with 17 mmcfd x 33 hrs
Program 2 (21 days): 44 mmcfd withdrawal x 5 hr, 2 hr SI, 17 mmcfd inj x 15 hr, 2 hr SI; Repeat 5 days; Repressure with 17 mmcfd x 5 hrs

Lastly, the history-matched model estimated the water production (Figure 6-11) and reservoir pressure (Figure 6-12). The information in Figure 6-11 was useful for planning purposes to understand how much water was forecasted to be produced during the test, what facilities will need to be in place to capture the water, and to determine an appropriate water disposal plan.

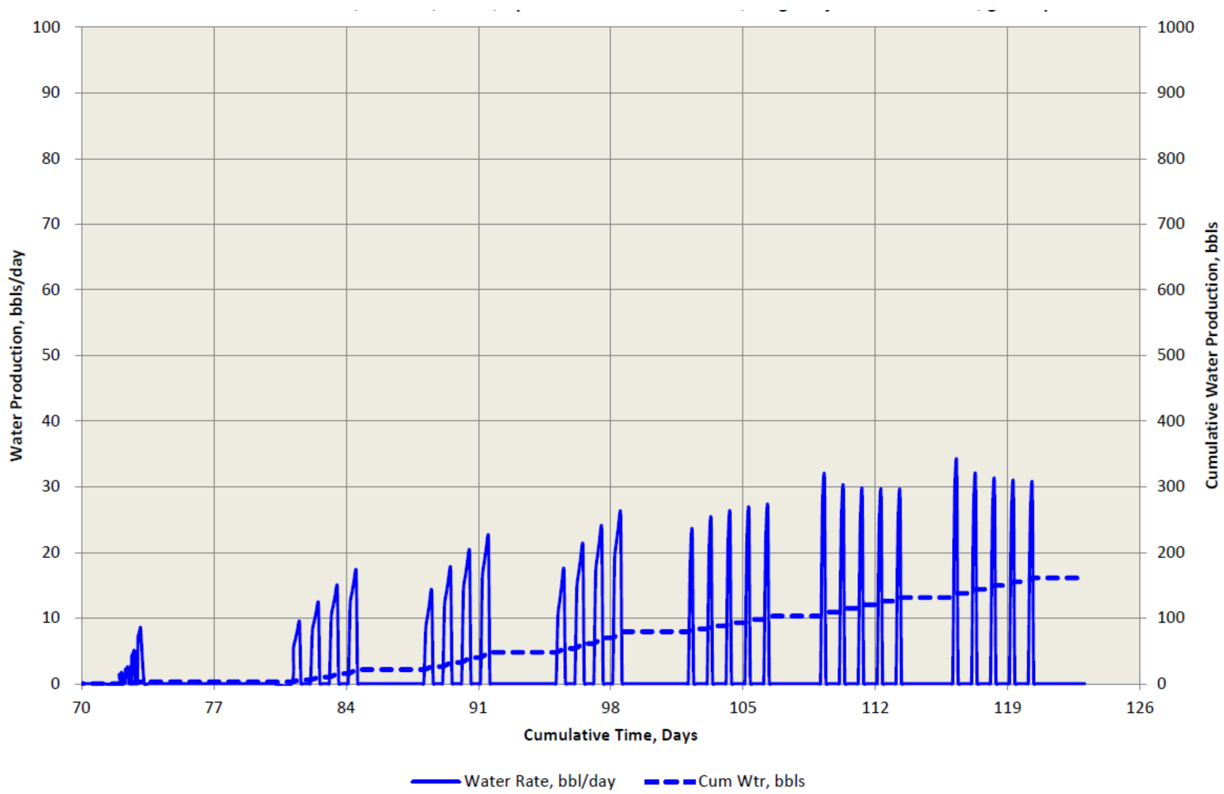


Figure 6-11 King Island Draft Compression Testing Program Model - March 2013
Water Production Volumes – Cycle Testing Post Bubble Build (InjLayers 1-15)
Bubble Size – 950 MMcf; 7.5% PV; 15d SI; Cycle Volume = 1.5% Bubble Size; Target Inj Rate = 17 mmcfd; gravel pack

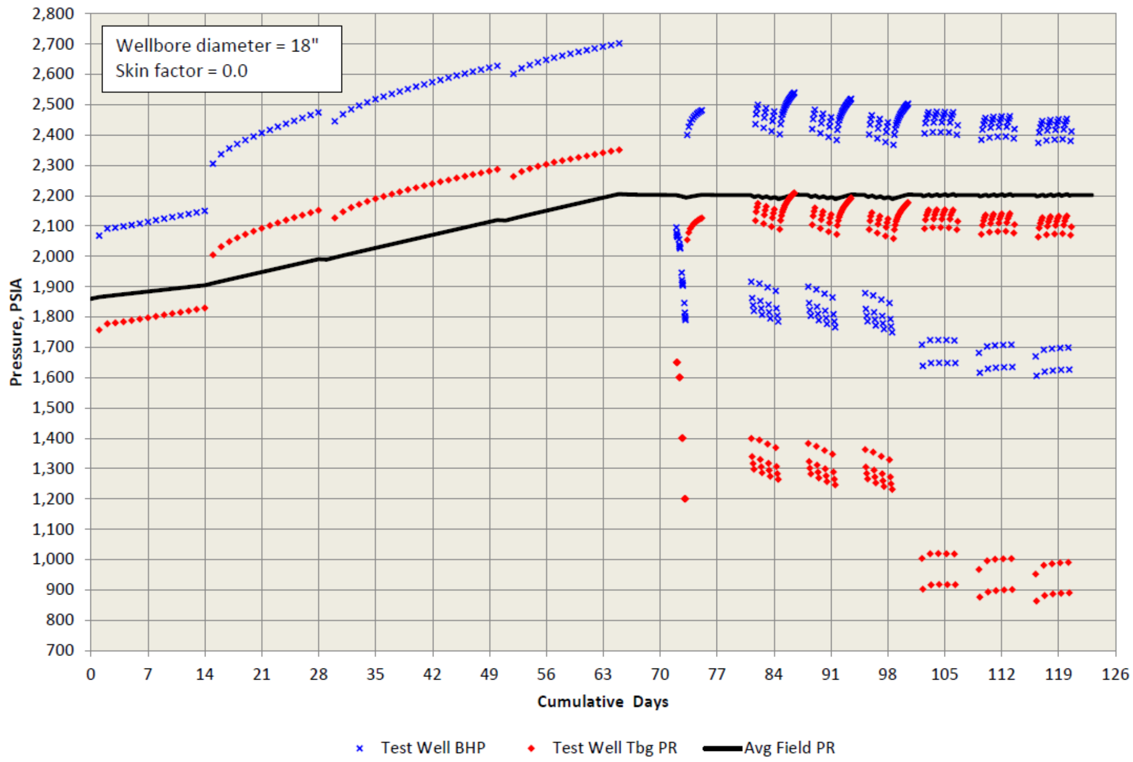


Figure 6-12 King Island Draft Compression Testing Program Model - March 2013 Pressures (InjLayers 1-15) Bubble Size – 950 MMcf; 7.5% PV; 15d SI; Cycle Volume = 1.5% Bubble Size; Target Inj Rate = 17 mmcfd; gravel pack

6.4.4 Why the Predicted Percentage of Native Gas in the Produced Air Volumes Changed

MHA made a number of sensitivity runs with the history-matched model to determine what factor caused the percentage of native gas in the withdrawal stream to decrease significantly in the compression testing simulations for the calibrated model versus the early model.

The conclusion of the sensitivity cases was that the decrease in the magnitude of permeability caused the decrease in the percentage of native gas in the withdrawal stream. Even with the new J-function characterization input into the early model, the model was still predicting +/- 5% native gas in the withdrawal gas stream. However, if the permeability in the early model was lowered to a constant 200 md, which was close to the average permeability distribution in the history-matched model, then the percentage of native gas in the produced gas stream drops to less than 1%, in line with the results of the history-matched model.

The controlling parameter is suspected to be the magnitude of the vertical permeability, which may allow the lighter natural gas to override the heavier injected air.

6.5 FINAL COMPRESSION TESTING PLAN

To conduct the compression testing program, an Injection / withdrawal (I/W) test well would be drilled and completed in the King Island Gas Field. Two existing nearby gas wells would be utilized as observation wells, and temporary air compression equipment and other equipment would be installed to perform the test. Addressing the unknown percentage of natural gas in the discharge air was critical for the project team as it entered the design phase of the Temporary Site Facility (TSF) to support the test and to ensure the safety of the operation.

Additional simulations were performed to determine the size of air bubble necessary to safely perform the withdrawal tests. Various bubble sizes were investigated with the calibrated King Island model. The largest size was 950 MMscf, and the smallest size was 500 MMscf. The final selected size of 500 MMscf (as seen in Figure 6-17) was expected to achieve the desired withdrawal cycling rates without significant water production (less than 80 barrels per MMscf), with less than 200 psi drawdown in the reservoir around the I/W well, and with low concentrations of methane (less than 1%). The bubble could be built with reasonably-sized compressors to achieve the desired volume within a 60-day period.

6.6 TEMPORARY SITE FACILITY (TSF) PLANNING AND DESIGN

Once the testing objectives were finalized and the initial test program drafted, the next step was to develop a preliminary engineering design for the Temporary Site Facility (TSF) that would be constructed to support the testing objectives/plan. The TSF work would involve three distinct stages (discussed in more detail in Section 6.13):

1. Site preparation
2. Construction of the injection / withdrawal well
3. Construction of the compression and balance of plant (BOP) equipment

A preliminary engineering design of the TSF (Figures 6-13 and 6-14) was developed for the project, which served as the basis for two main areas of work: a) Conducting a risk identification study, and b) Assisting with the sourcing of the engineering, procurement, and construction of the required facilities. Figure 6-13, the Preliminary General Arrangement (GA), showed the initially proposed layout of the equipment. The GA was utilized, among other items, to determine the total amount of space required for the facilities. Figure 6-14, the Preliminary Process Flow Diagram (PFD), indicated the general flow of plant processes and equipment. The PFD displays the relationship between major equipment of a plant facility but does not show minor details such as piping details and designations.

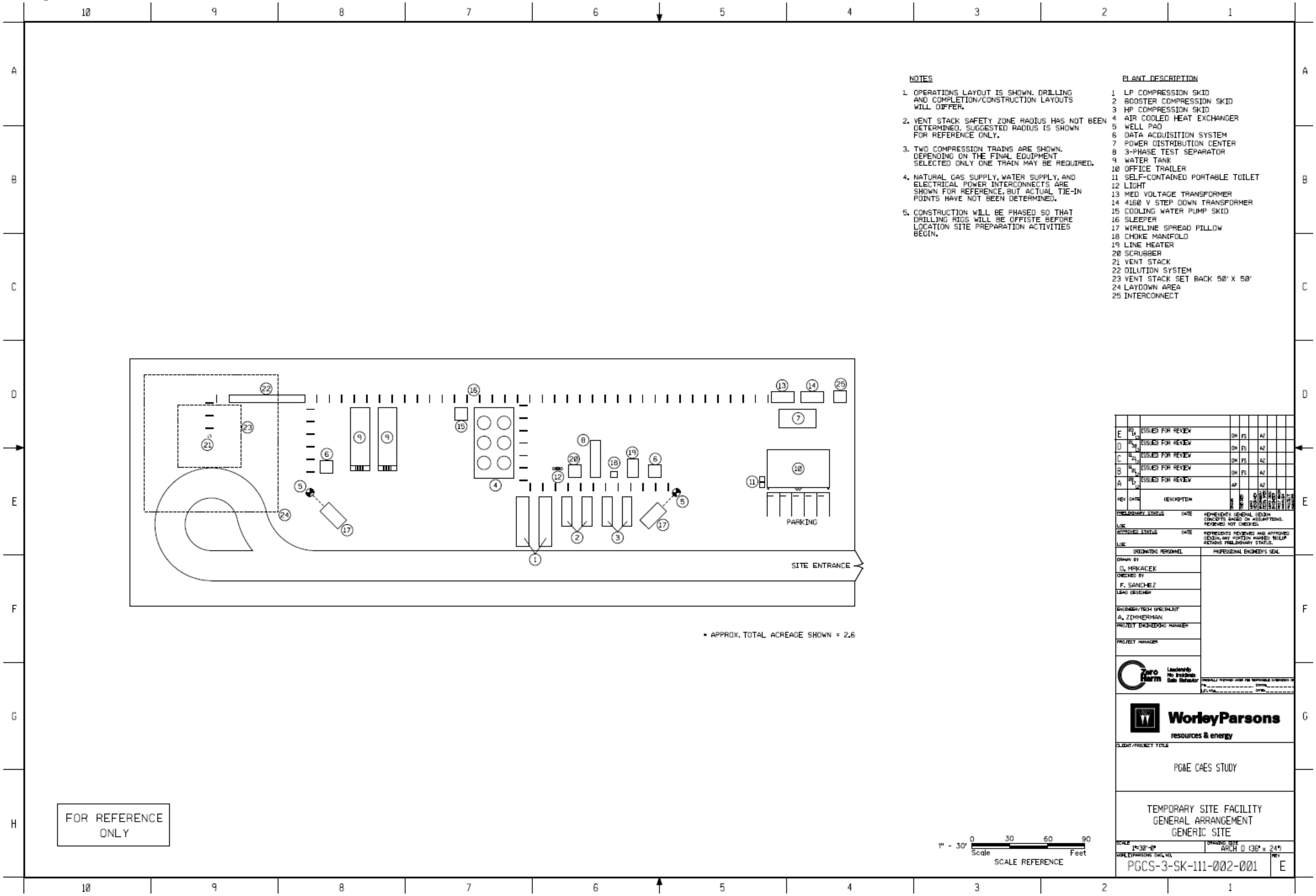


Figure 6-13 Preliminary General Arrangement for TSF

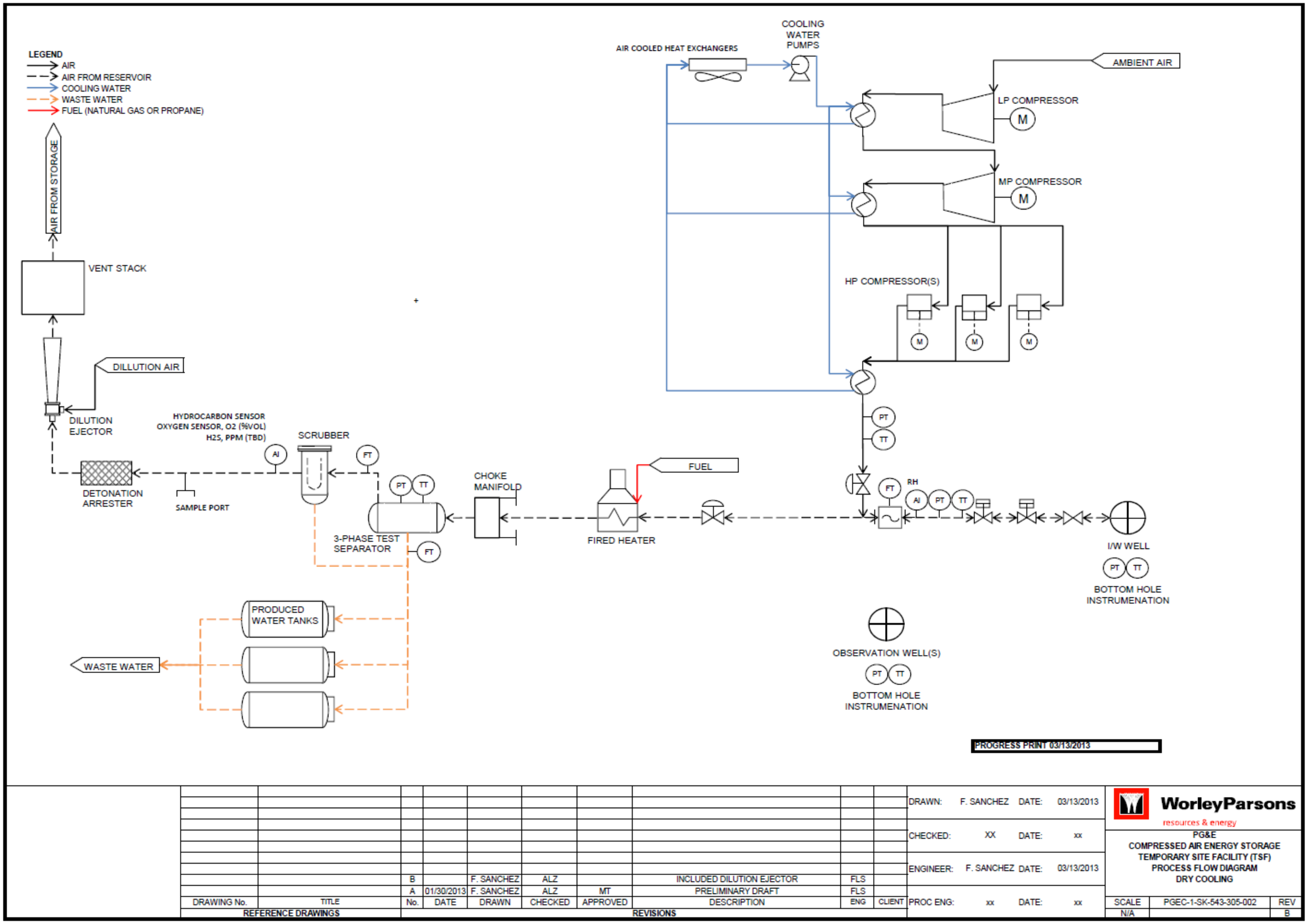


Figure 6-14 Preliminary Process Flow Diagram for TSF

6.7 RISK IDENTIFICATION (HAZID STUDY)

PG&E's primary objective during the feasibility study, and specifically as it related to the air injection test, was to keep the test site safe for workers and the public. The objective of this CAES feasibility study was to determine if depleted natural gas reservoirs can be re-purposed as part of a CAES facility; if the use of depleted natural gas reservoirs can be technically and economically proven, the applicability of CAES would broaden to areas of the United States and globally where the geology is similar to that investigated herein. Although natural gas reservoirs can be considered "depleted," natural gas is known to be present in quantities that have been deemed uneconomic to recover. Therefore, the possibility exists that during the TSF operation, the injected air will mix with the existing natural gas (as shown in the modeling work) within the reservoir such that the withdrawn air will contain concentrations of natural gas that may create a hazardous condition.

The Project Consulting Engineer (PCE) commissioned a study for the TSF using the hazard analysis tool known as HAZID. The study was conducted over a two-day period. The primary objective of the HAZID study, which was facilitated by an independent third-party, was to identify credible hazards and potential safety, environmental, and operational issues for the CAES TSF Unit. The HAZID methodology identifies general consequential impacts from the processes under study at a high level and identifies safeguards to prevent or mitigate these impacts. When safeguards are deemed not to be sufficient, the HAZID participants (cross-functional team of project participants from multiple disciplines as well as subject-matter experts) make recommendations to the design/operations that can lead to reducing the risks identified. The HAZID was designed as a brainstorming exercise, which encourages discussion between members of the review team to systematically examine the impact of the credible deviations on the design.

HAZID is an accepted hazard analysis tool. Figure 6-15 shows a flowchart of the analysis process. The review was conducted in compliance with Recognized and Generally Accepted Good Engineering Practice (RAGAGEP) and industry standards, and the following regulations:

- 29 CFR 1910.119, Federal Occupational Safety & Health Administration (OSHA) Process Safety Management (PSM).
- Environmental Protection Administration (EPA) Risk Management Planning Rule (60 CFR Part 68).

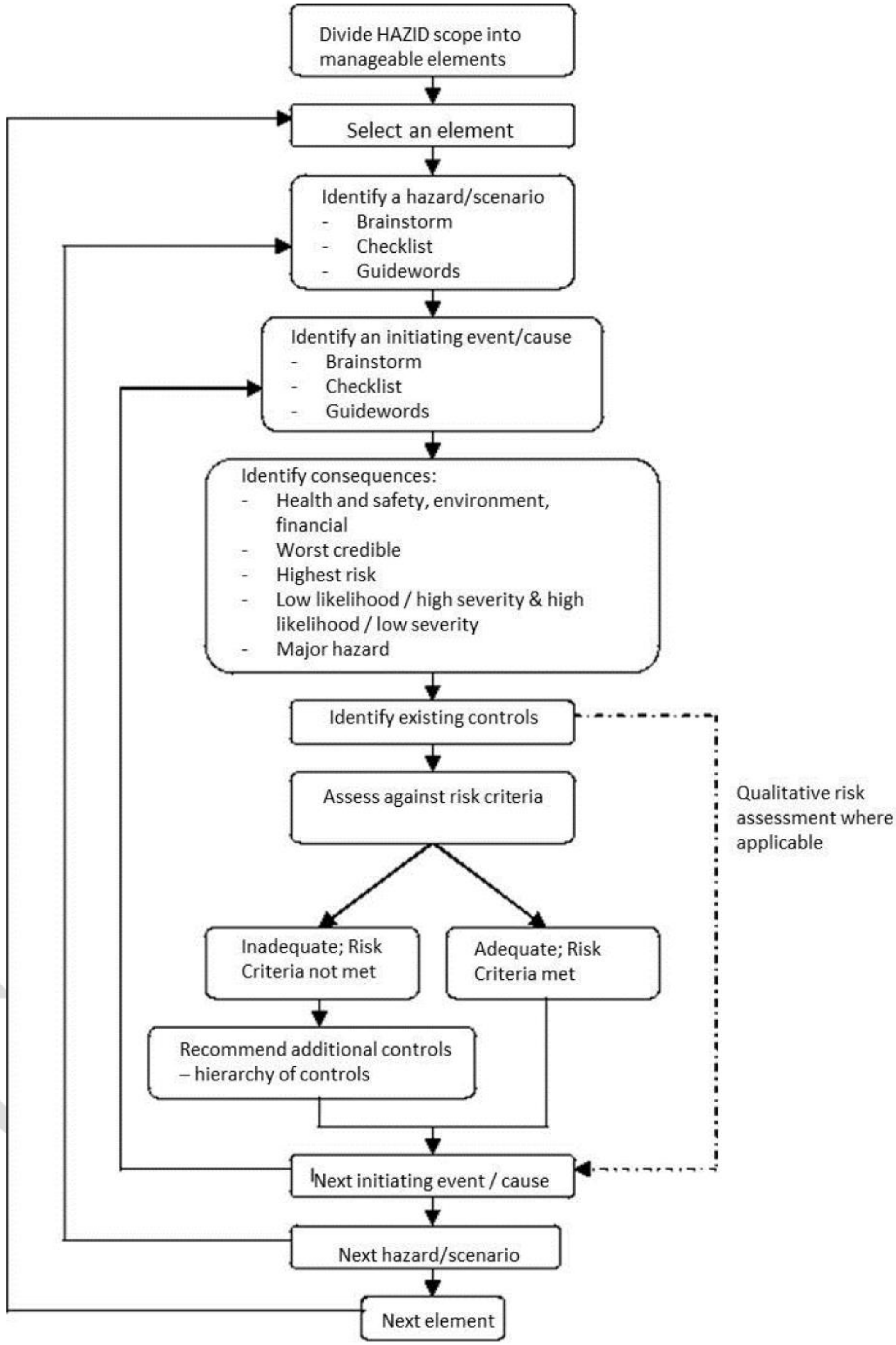


Figure 6-15 HAZID Workshop Process Flowchart

As a result of the HAZID, 16 recommendations were formulated for consideration by the project team as part of the overall testing plan and design of the TSF equipment.

6.7.1 Risk Identification (Additional Analysis)

As a result of the HAZID review, and as a result of discussion among the HAZID team members, additional analysis and reservoir modeling were conducted to determine the appropriate safety measures to employ to address the withdrawal operations.

The chief safety concern for the project team was driven by the potential of creating a combustible mixture that would be present while withdrawing a mixture of ambient air and an unknown percentage of natural gas from the reservoir.

The team noted that three basic conditions are required for fire to take place (Figure 6-16):

- Fuel – the reducer; any combustible material, solid, liquid or gas. Most solids and liquids must vaporize before they will burn.
- Oxygen – the oxidizer; sufficient oxygen must be present in the atmosphere surrounding the fuel for fire to burn.
- Heat – sufficient energy must be applied to raise the fuel to its ignition temperature.

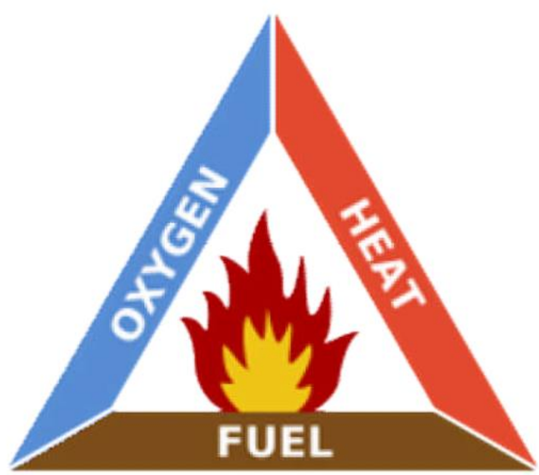


Figure 6-16 Conditions Required for Fire

Of the three components of the fire triangle identified, the modeling efforts described earlier, attempted to determine the estimated amount of fuel (in this case, percentage of natural gas) that would be present in the withdrawal stream. The initial testing plan assumed the test would be conducted using ambient air, whereby the amount of oxygen (21%) was known. Therefore, if the percentage of fuel/natural gas was high enough, two of the components required for a fire would exist (oxygen and fuel).

Most of the early modeling efforts, based on an injection / withdrawal test using ambient air, showed varying results as it related to the percentage of methane. While the revised dynamic modeling results discussed previously were promising, modeling by nature entails uncertainty, which can be reduced, but never completely eliminated. Modeling programs are typically supported by monitoring when the modeling is used to support critical decisions, and reliance upon the modeling results is only increased when monitoring data validate the predicted results. Given that no actual field results existed to rely upon from previous tests, additional consideration was given as to how to conduct a safe air injection / withdrawal test in a depleted natural gas reservoir with some native gas, while advancing the knowledge of utilizing depleted natural gas reservoirs for CAES.

The PCE considered alternative process options that would accomplish the project objectives and reduce the risk. Two options were investigated:

1. Conduct an <u>injection-only</u> program using ambient air. This option may accomplish the minimum test program objectives while ensuring safety at the surface facility by eliminating the withdrawal of potential combustible mixtures. However, critical information regarding deliverability, rate dependent skin effect (i.e., the flow rate at which turbulent flow occurs), water production, or natural gas concentration would not be collected. As such, the data used to refine the computer reservoir model would not be as robust, and the model would not be validated for flow conditions.
2. Conduct an <u>injection and withdrawal program</u> first using "oxygen-depleted" air (reduce the percentage of oxygen in the injected air stream to less than 5%). Based on the initial results, ambient air injection and withdrawal testing could also occur. Analysis by the PCE determined that limiting the amount of oxygen in the air stream would significantly reduce the possibility of forming a combustible mixture of residual natural gas and air within the reservoir.

After consideration, the project team selected option #2.

6.8 OVERVIEW OF REVISED TESTING PROGRAM AND ANALYSIS

Based on option #2 outlined above, additional modeling and computer simulations were conducted in support of the design and operation of the testing program. The modeling was used to assist in baseline test planning and to predict test performance related to reservoir pressure response, air bubble development, deliverability, water production, and the percentage of natural gas in the withdrawal stream.

The revised testing plan would be performed over a period of approximately 90 days. The test involves subsurface injection of oxygen-depleted air (> 95% N2) to build an approximately 500 million standard cubic feet (MMscf) "bubble", which is approximately 6 to 10% of the reservoir volume expected to be needed for operation of a full scale CAES plant (5 to 8 billion standard cubic feet [BSCF]), and approximately 3 to 4% of the estimated original gas in place (13.8

BSCF). During and after building the air bubble, the I/W well and observation wells will be subjected to various tests. The data from these tests will be used to evaluate reservoir and well performance, to validate and update the reservoir model, and for full-scale CAES plant design. Figure 6-17 shows the results from a fully compositional reservoir model (Eclipse 300). It depicts a revised testing plan and the scheduled phases of the compression testing program and anticipated injection and flow rates.

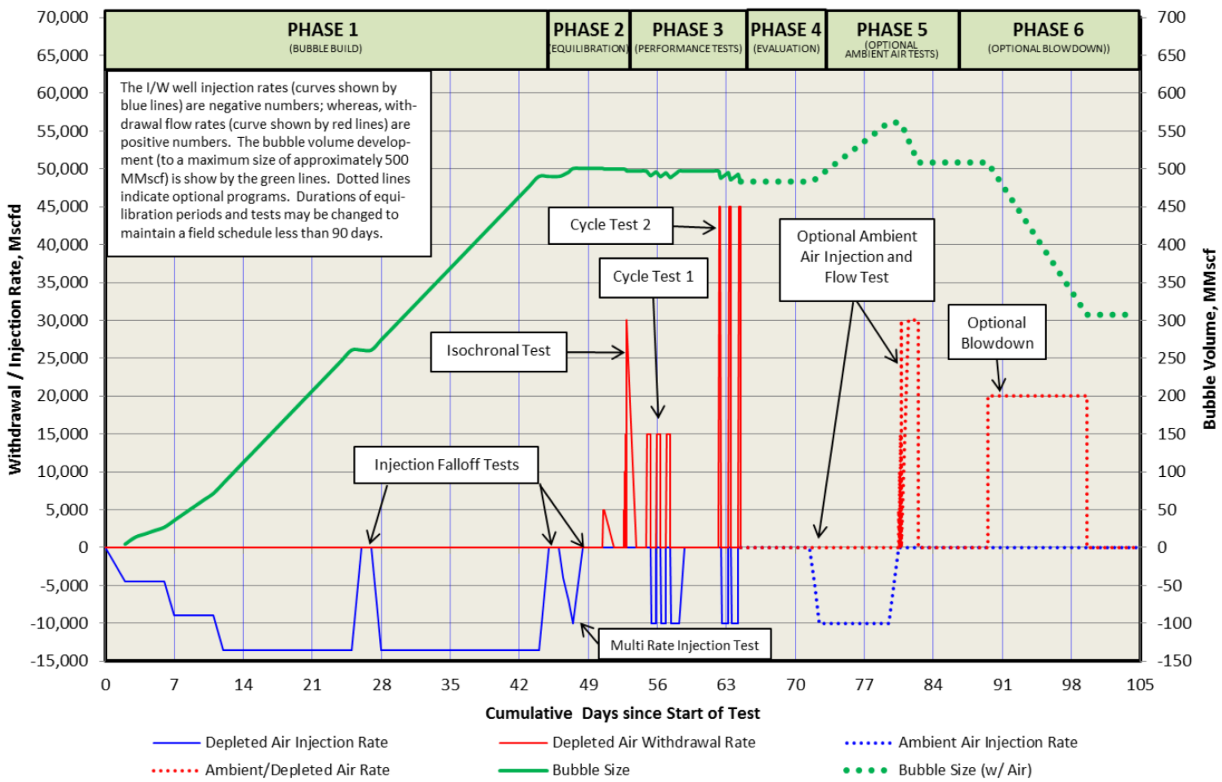


Figure 6-17 King Island Compression Testing Program

6.8.1 Performance Tests

Reservoir and well performance tests would be performed during the compression test. The purpose of performance tests is to evaluate both I/W well and reservoir performance properties. The timing of the tests during the compression testing program schedule is shown in Figure 6-17. Five types of well and reservoir performance tests are described in Table 6-1.

Table 6-1 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.	12 to 48 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).
Isochronal Test	1	Flow after flow with increasing rates (4 rates x 1 hour each) from 5 to 30 MMscfd.	<1 day	Determine air flow potential, absolute open flow, skin damage and rate dependent skin.
Interference	2	Monitor pressure response in observation well 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 (does not reflect optional testing)	2	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.

6.8.2 Compression Test Model Simulations

The reservoir model developed for the King Island Gas Field was used to run simulations of the testing program to predict expected outcomes. Following a series of sensitivity analyses, the project team selected the key model elements and compression test program assumptions listed below for a model simulation for planning purposes:

- Oxygen-depleted air injection
- Local grid refinement of 5 feet by 5 feet around the I/W well
- Grid block thickness of about 5 feet
- Maximum injection rate of 14 MMscfd
- 500 MMscf bubble size
- I/W completion interval of 40 feet below top of reservoir
- Cycle testing Series 1 withdrawal rate of 15 MMscfd, and a cycle testing Series 2 withdrawal rate of up to 45 MMscfd

The model simulation incorporating the above elements and assumptions is presented in Figures 6-18, 6-19, and 6-20. Key simulation results for the compression testing program are as follows:

- The native gas concentrations in withdrawn gas during cycle testing increased with each cycle to a maximum of 0.18% at the end of Cycle Testing Series 2 (Figure 6-18).
- The maximum water production rate (instantaneous) is 299 barrels of water per day (BWPD) (Figure 6-19).
- The maximum well tubing head pressure (WTHP) during injection was 1,921 psi (Figure 6-20).
- The maximum bulk-average reservoir pressure simulated by the model during injection was 2,178 psi (Figure 6-20).

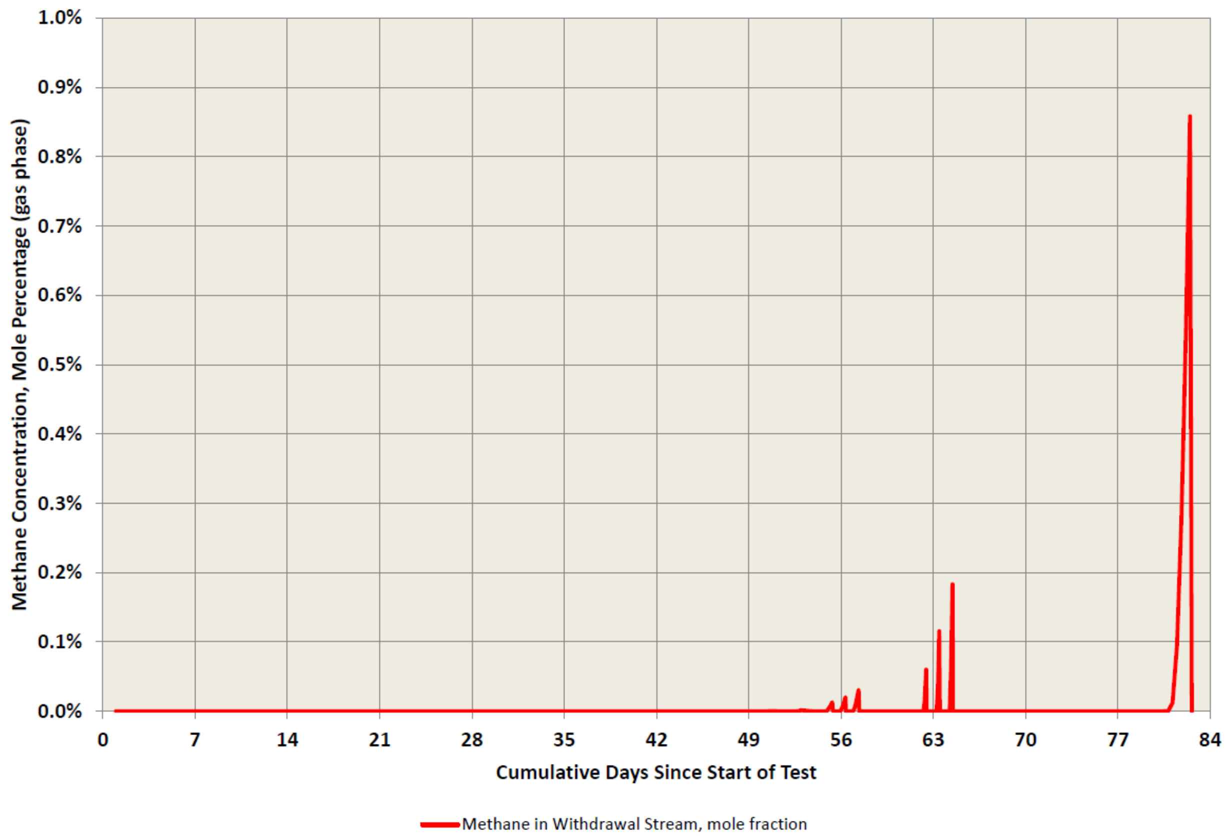


Figure 6-18 Model % Methane in Withdrawal Stream –30x30 (5x5 ft grid cells) LGR

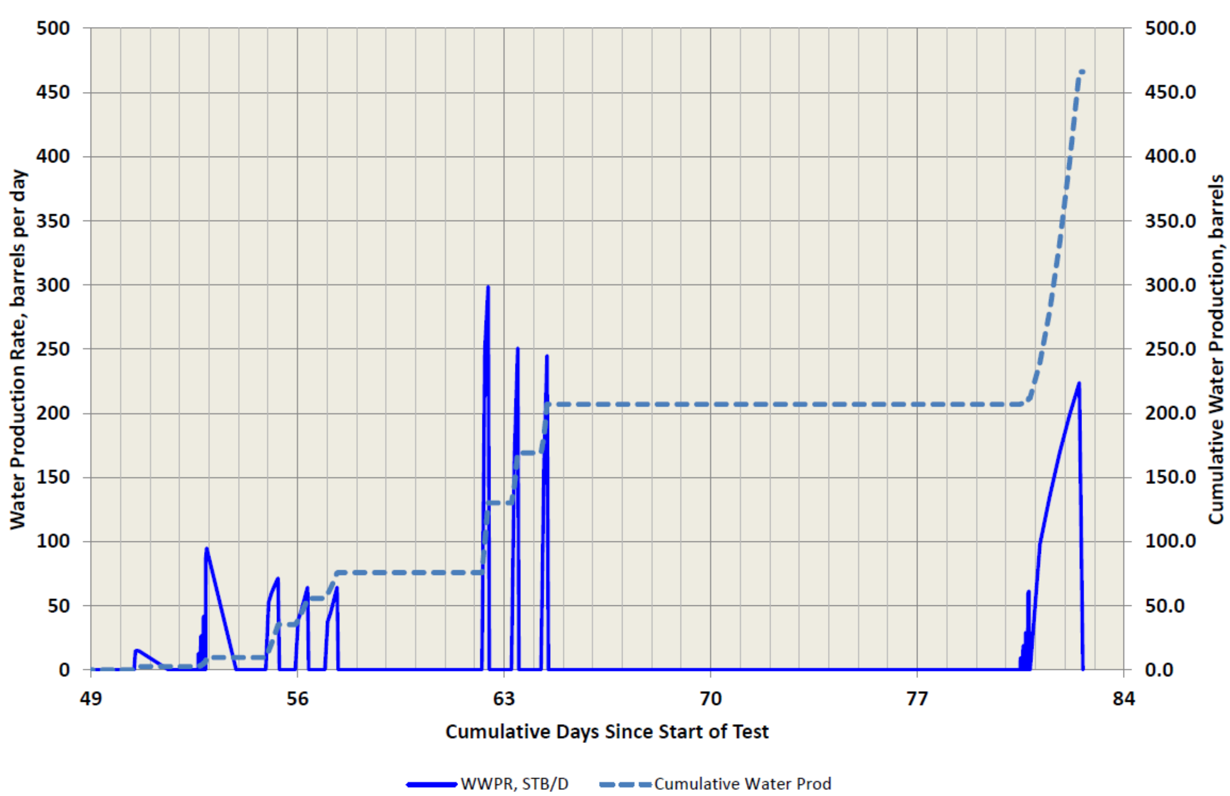


Figure 6-19 Model Water Production –30x30 (5x5 foot grid cells) LGR

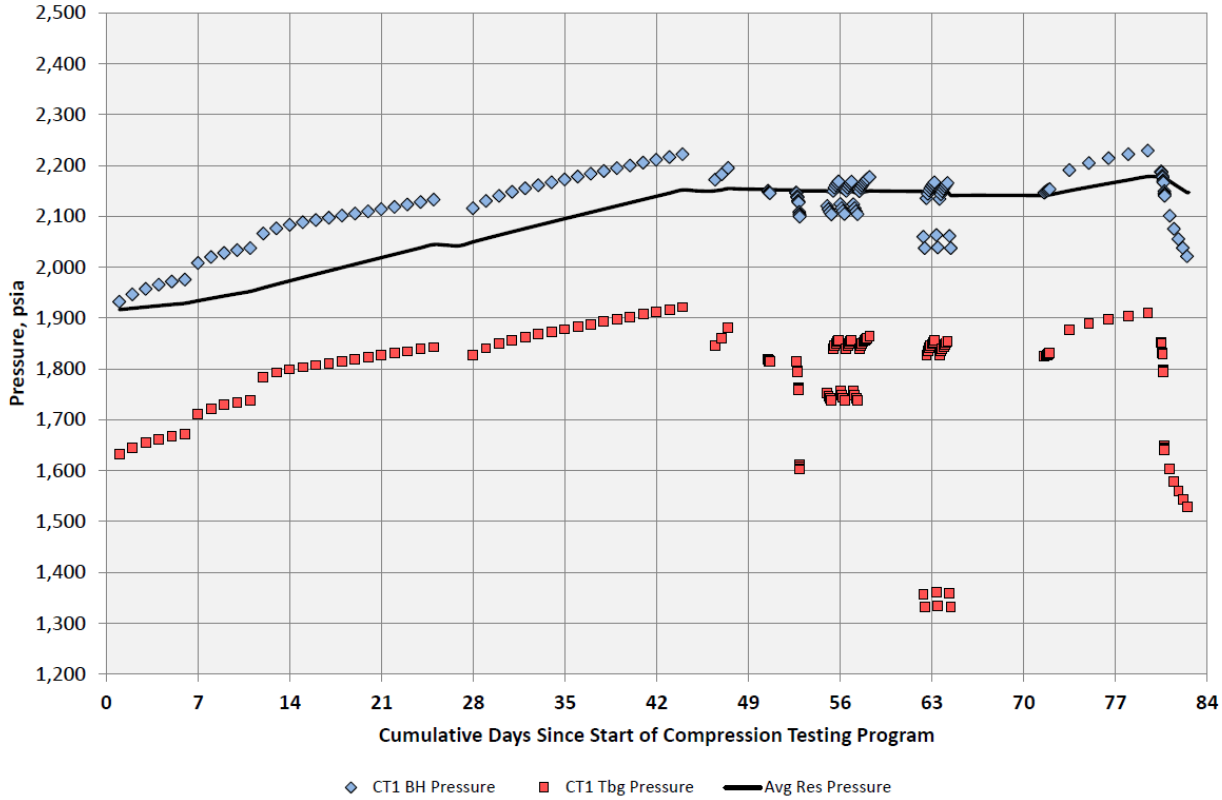


Figure 6-20 Model Pressures – 30 x30 (5x5 foot grid cells) LGR

6.8.3 Operating Conditions

Table 6-2 shows the predicted TSF operating conditions based on the preliminary reservoir modeling using the Eclipse reservoir model (information only, not relied on for design). All parameters, with the exception of temperature, were based on the output from the compression test model simulation represented in Figures 6-18 to 6-20.

Table 6-2 Predicted TSF Operating Conditions

Operating Parameter	Measurement Location	Approximate Value
Maximum injection pressure	Well head	1,921 psig
Minimum injection pressure	Well head	1,632 psig
Maximum injection flow rate	I/W well manifold	13.5 MMscfd
Minimum injection flow rate	I/W well manifold	4 MMscfd
Maximum injection temperature	Well head	140 F
Maximum moisture content of injection air	N_2 Generator	Saturated
Maximum withdrawal air native gas percentage	I/W well manifold	0.18%
Minimum withdrawal air native gas percentage	I/W well manifold	0%
Maximum instantaneous water production	Water tank	299 BWPD
Maximum weekly water production	Water tank	259 barrels

The I/W well will be operated so as not to exceed the formation parting pressure in the target injection zone. To achieve this, the maximum bottomhole injection pressure will not exceed 2,500 psi (approximately 2,200 psi tubing head pressure), or the maximum allowable pressure determined by a step rate test, as required by the Underground Injection Control (UIC) permit issued by the United States Environmental Protection Agency (EPA) for the I/W well.

6.8.4 Detailed Compression Testing Plan

The compression testing program was divided into up to six phases, as presented in Table 6-3 and discussed in more detail below.

Table 6-3 Summary of Compression Testing Program Phasing and Activities

Test Phase		Test Activity	Tentative Duration
1	Bubble Building	N_2 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
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 N2 injection/withdrawal/shut-in cycling	3 ½ days
		Shut-in/Equilibration	4 days
		Series 2 N2 injection/withdrawal/shut-in cycling	3 ½ days
4	Preliminary Data Evaluation and Post-Test Equilibration	Evaluate data, PG&E decision regarding further testing	Up to 7 days
		Shut-in well and post-test monitoring (if Phase 5/6 is not performed)	60 days or TBD
5	Additional Testing (TBD)	Additional testing (TBD)	11 days
6	Bubble blowdown (TBD)	Additional testing (TBD)	10 days

The actual durations of the test phases may change based on the equipment mobilized, equipment performance under field conditions, and the results of the evaluation of the test data from Phases 1-3. A detailed schedule is presented in Table 6-4.

Table 6-4 Detailed Compression Testing Program Schedule

COMPRESSION TESTING PROGRAM & SCHEDULE
PG&E TEST INJECTION / WITHDRAWAL WELL 1 - KING ISLAND FIELD

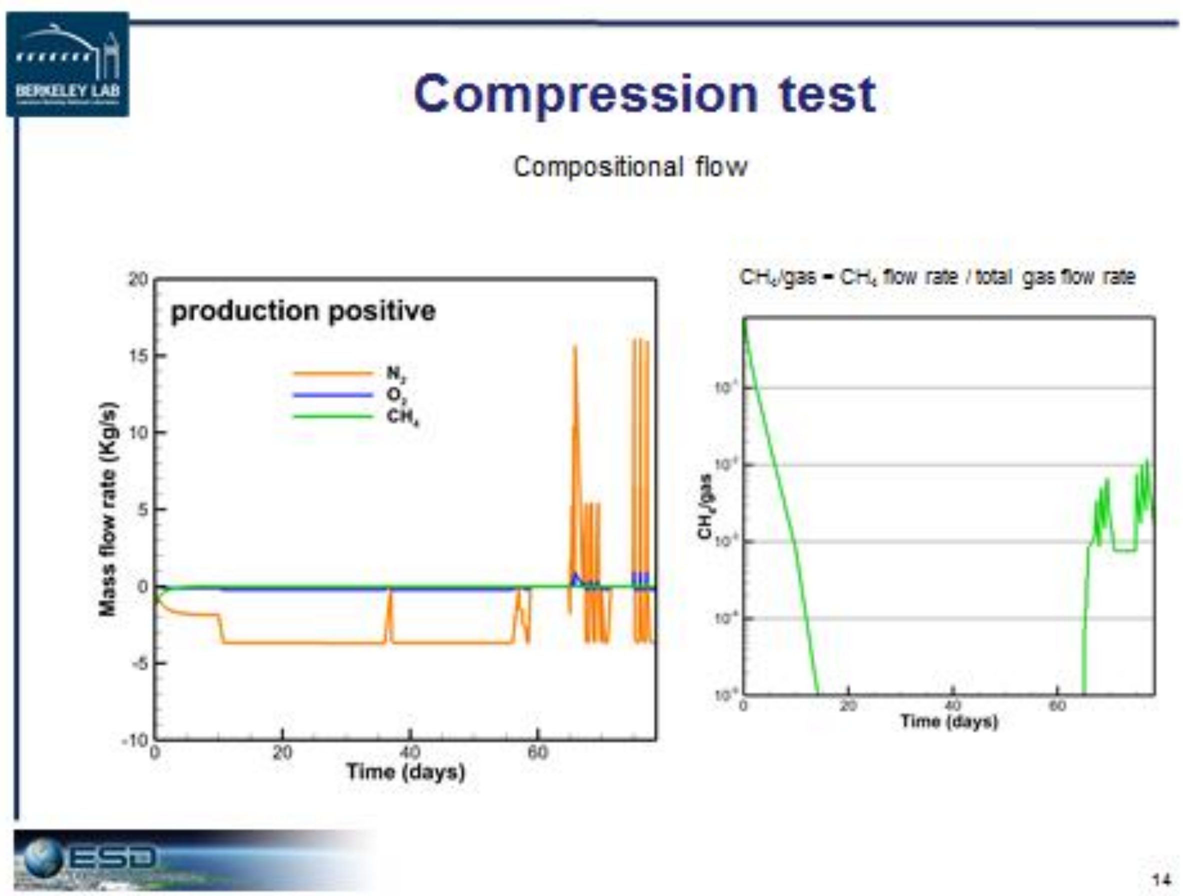
Revision Date: 11/17/2014 + plus = withdrawal - minus = injection

	Test Event Schedule	Schedule Calendar Date	'Air' Rate, mcfd	Period, Hours	Period, Days	Cumulative Testing Days	'Air' Volume Segment, mmcf	I/W Cycling Cum Volume, mmcf	Cumulative 'Air' Inventory
	OXYGEN-DEPLETED AIR								
1	**Start bubble build**	2/2/2015	0	-	-	-	0		0
2	Build		-4,500	144.0	6.000	6.000	-27,000		-27,000
3	Build		-9,000	120.0	5.000	11.000	-45,000		-72,000
4	Build		-13,500	336.0	14.000	25.000	-189,000		-261,000
5	Falloff test and logging	2/27/2015	0	48.0	2.000	27.000	0		-261,000
6	Build		-13,500	408.0	17.000	44.000	-229,500		-490,500
7	Falloff test and logging	3/18/2015	0	48.0	2.000	46.000	0		-490,500
8	Pre-test flow	3/20/2015	5,000	4.0	0.167	46.167	833		-489,667
9	Shut-in and pressure build-up		0	24.0	1.000	47.167	0		-489,667
10	Modified Isochronal1	3/21/2015	5,000	1.0	0.042	47.208	208		-489,458
11	SI Isochronal1		0	1.0	0.042	47.250	0		-489,458
12	Modified Isochronal2		10,000	1.0	0.042	47.292	417		-489,042
13	SI Isochronal2		0	1.0	0.042	47.333	0		-489,042
14	Modified Isochronal3		15,000	1.0	0.042	47.375	625		-488,417
15	SI Isochronal3		0	1.0	0.042	47.417	0		-488,417
16	Modified Isochronal4		30,000	1.0	0.042	47.458	1,250	-	-487,167
17	Final Shut-in and Falloff Test		0	24.0	1.000	48.458	0	0	-487,167
18	**Program1 (Cycle Testing)**	3/22/2015	15,000	10.0	0.417	48.875	6,250	6,250	-480,917
19	Program1		0	1.0	0.042	48.917	0	6,250	-480,917
20	Program1		-10,000	12.0	0.500	49.417	-5,000	1,250	-485,917
21	Program1		0	1.0	0.042	49.458	0	1,250	-485,917
22	Program1	3/23/2015	15,000	10.0	0.417	49.875	6,250	7,500	-479,667
23	Program1		0	1.0	0.042	49.917	0	7,500	-479,667
24	Program1		-10,000	12.0	0.500	50.417	-5,000	2,500	-484,667
25	Program1		0	1.0	0.042	50.458	0	2,500	-484,667
26	Program1	3/24/2015	15,000	10.0	0.417	50.875	6,250	8,750	-478,417
27	Program1		0	1.0	0.042	50.917	0	8,750	-478,417
28	Program1		-10,000	21.0	0.875	51.792	-8,750	0	-487,167
29	**Shut-in and Data Evaluation**		0	72.0	3.000	54.792	0	0	-487,167
30	**Program2 (Cycle Testing)**	3/28/2015	45,000	5.0	0.208	55.000	9,375	9,375	-477,792
31	Program2		0	1.0	0.042	55.042	0	9,375	-477,792
32	Program2		-10,000	17.0	0.708	55.750	-7,083	2,292	-484,875
33	Program2		0	1.0	0.042	55.792	0	2,292	-484,875
34	Program2	3/29/2015	45,000	5.0	0.208	56.000	9,375	11,667	-475,500
35	Program2		0	1.0	0.042	56.042	0	11,667	-475,500
36	Program2		-10,000	17.0	0.708	56.750	-7,083	4,583	-482,583
37	Program2		0	1.0	0.042	56.792	0	4,583	-482,583
38	Program2	3/30/2015	45,000	5.0	0.208	57.000	9,375	13,958	-473,208
39	**Shut-in and Data Evaluation**	3/31/2015	0	168.0	7.000	64.000	0	13,958	-473,208
40	**Optional AMBIENT AIR Program3**	4/7/2015	-5,000	12.0	0.500	64.500	-2,500	11,458	-475,708
41	Optional Program3		-10,000	180.0	7.500	72.000	-75,000	-63,542	-550,708
42	Optional Program3		0	24.0	1.000	73.000	0	-63,542	-550,708
43	Optional Program3	4/16/2015	5,000	1.0	0.042	73.042	208	-63,333	-550,500
44	Optional Program3		0	1.0	0.042	73.083	0	-63,333	-550,500
45	Optional Program3		10,000	1.0	0.042	73.125	417	-62,917	-550,083
46	Optional Program3		0	1.0	0.042	73.167	0	-62,917	-550,083
47	Optional Program3		15,000	1.0	0.042	73.208	625	-62,292	-549,458
48	Optional Program3		0	1.0	0.042	73.250	0	-62,292	-549,458
49	Optional Program3		30,000	1.0	0.042	73.292	1,250	-61,042	-548,208
50	Optional Program3		0	1.0	0.042	73.333	0	-61,042	-548,208
51	Optional Program3		30,000	40.0	1.667	75.000	50,000	-11,042	-498,208
52	**End of Testing**	4/18/2015	0	-	-	75.000	0	-11,042	-498,208

During the approximately 90-day test, the test well would be used to perform a series of injection, withdrawal, and pressure fall-off and build-up tests while monitoring the test well and the observation wells.

6.9 SEPARATE NATURAL GAS MODELING EFFORT

In addition to the modeling performed by the PCE, PG&E worked with experts from Lawrence Berkeley National Laboratory (LBNL) to perform a parallel modeling exercise to determine, among other parameters, the percentage of methane in the withdrawal stream. The results of that modeling effort are depicted in Figure 6-21.



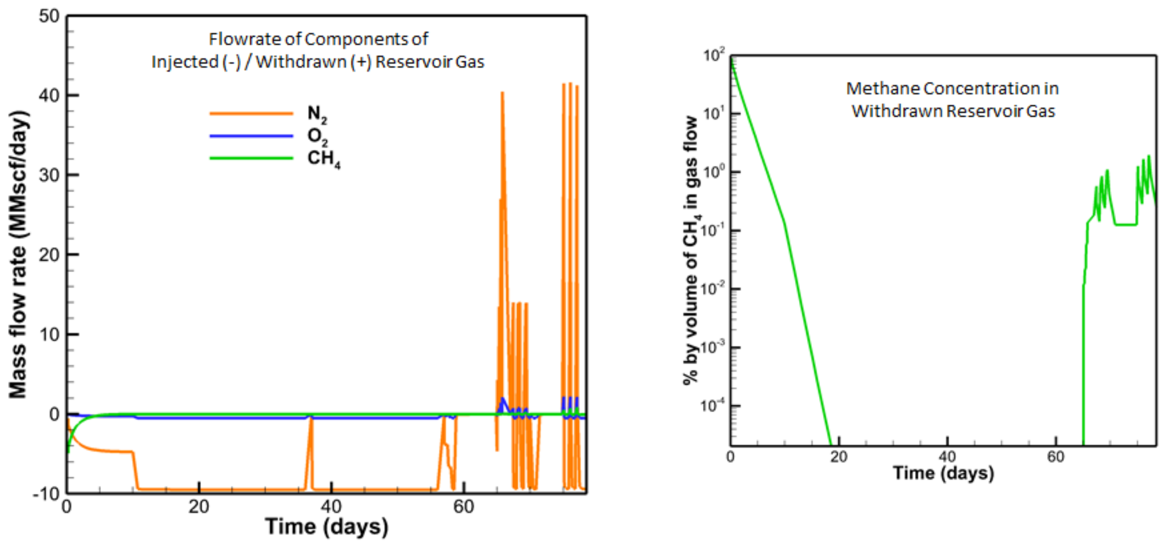


Figure 6-21 Natural Gas LBNL Model Results (Courtesy LBNL, Earth Sciences Div.)

As can be seen from Figures 6-18 and Figure 6-21, both modeling efforts, performed by different entities using different models but the same information, indicated that the maximum percentage of methane in the withdrawal stream would be less than 1% and that it would occur during the optional ambient air test.

6.10 RISK MITIGATION STRATEGIES EMPLOYED

Of all the risks discussed and recommendations formulated, the highest priority involved the prevention of flammable mixtures in the withdrawal stream (U.S. Bureau of Mines 1985 and 1999). Several strategies were developed and incorporated into the TSF design specification to minimize the risk of such an occurrence:

- **Minimization of ignition sources** – Ignition of a combustible mixture can come from a variety of sources, including an open flame, spark from a grinder, static electricity, or even a lightning strike. Elimination of certain sources of ignition is relatively easy by simply forgoing activity onsite that would generate a spark or require an open flame. Others, such as a spark from static electricity, are very difficult to eliminate entirely. A 25-foot radius buffer zone was incorporated around the vent.

- **Monitoring and measurement of test operating conditions** – Instrumentation of various operating parameters is critical in detecting potentially dangerous conditions. In particular, the continuous analysis of oxygen and methane contents in the flowing stream during both injection and withdrawal operations provides the facility operators with advanced warning as concentrations approach established limits. Monitoring additional operating parameters such as pressure and temperature also ensure the operation can be conducted safely.

- **Oxygen/gas mixtures below the combustible limit** – Limiting the concentration of oxygen in the injected air by reducing the oxygen content of the injected air to below a level that will support combustion, significantly decreases the likelihood that a combustible mixture will flow to the surface during withdrawal operations (Zlochower and Green, n.d.) The use of nitrogen membrane technology was chosen to reduce the oxygen content to less than 8%, which is considered to be the safe limit at the elevated pressures of the compression test (see U.S. Bureau of Mines, 1999, Figure 43).

  Limiting the concentration of methane in the withdrawal air also significantly decreases the likelihood that a combustible mixture will flow to the surface. At elevated pressures, the lower flammability limit for methane in air can be reduced to less than 4.0% (van den Schoor et al., n.d.). If the methane concentration exceeds acceptable limits based on flowing pressure and temperatures, the withdrawal tests will be shut-in to ensure than an unsafe concentration does not enter the wellbore and is not produced to the surface.

- **Operating procedures and control limits** – Written operating procedures will be provided to onsite personnel for use throughout the testing period. Operators will be appropriately trained in all aspects of the facility operation during both normal and abnormal conditions. The procedures will indicate the safe operating parameters for the various equipment and emergency procedures during an operational upset.

  Control equipment will be configured with documented set points that are well within the safety limits and approved by PG&E (see Decision Matrix discussion in Section 6.11). All critical controls are to be tested during installation for proper operation, the correct set points, and fail-safe operation.

6.11 DECISION MATRIX

As mentioned previously, due to the safety concerns described above, the decision was made to initially utilize oxygen-depleted air as the primary injected gas for reservoir testing purposes. Based on an evaluation of the test results with oxygen-depleted air (occurs during Phase 4 of the test), a decision would be made by PG&E as to whether it is safe to conduct additional testing (Phase 5) with ambient air. (See phases in Table 6-3.) A Decision Matrix was developed to establish guidelines for PG&E in making that decision. The Decision Matrix, identified pre-established criteria to guide operations of the test as well as to guide the decision on whether or not, once the initial testing with oxygen-depleted air was completed, to proceed with injection and withdrawal testing utilizing ambient air.

The Decision Matrix, summarized herein, provided a data evaluation protocol to be used by PG&E to support its operation and decision on whether to move beyond Phase 4. The decision matrix was prepared based on the Key Performance Indicator (KPI) of methane content in the withdrawn gas. The methane content will be continuously monitored during the test, then compared to the decision threshold levels developed. The reliability of methane monitoring instrumentation during operating conditions and the reliability of modeling to predict methane concentrations and their rate of change were also considered.

Three basic outcomes were envisioned, depending on the findings of Phases 1-3 of the compression test:

- A No-Go outcome indicates that it will be unsafe to proceed with air injection because of the risk of forming an explosive mixture.
- A Caution outcome indicates that it may be unsafe to proceed. Further checking and reconciliation of testing results are required before a decision to use or not use air can be made.
- A Confirm outcome indicates that the safety criteria to proceed with air injection have been met. A Confirm outcome is supposed when multiple measured test parameters align with reservoir modeling-derived parameters, the detection instrumentation operates within design limits, and methane concentrations are demonstrated to remain below the Lower Explosive Limit (LEL) with an adequate factor of safety.

The PCE and MHA will perform data evaluation required to help make this decision. The results would then be provided to a Testing Operations Review Committee ("TORC"), comprised of subject-matter experts, who then advise the project team on whether to proceed to Phase 5.

The following constraints were adopted:

- Oxygen-depleted air will be used for injection in the initial injection / withdrawal trial. For purposes of this project, oxygen-depleted air has been defined as containing 5% or less oxygen by volume. The oxygen content of the injected air will be monitored continuously. An alarm will sound if the oxygen content exceeds 5.5% by volume, and injection would be shut down if it exceeds 6.0%.
- Methane levels will be monitored in the withdrawn mixture continuously, and an alarm will be triggered if concentrations reach 2%. If levels exceed 5% in oxygen-depleted air, withdrawal will cease and the well will be shut-in.
- If injection and withdrawal trials using ambient air are undertaken, an alarm will be triggered if methane concentrations reach 1% at the continuous gas withdrawal monitors. Withdrawal will cease and the well will be shut-in if concentrations reach 2% in ambient air.

Input from the combustible gas analyzers, oxygen analyzers, pressure sensors, and temperature sensors would be routed to a data acquisition, control, and safety system to ensure the test was operated within safe parameters. During withdrawal, the control and safety system will work to shut in the well at the wellhead in the following events:

- A high methane content condition (5% when oxygen-depleted air is used and 2% if ambient air is used);
- A high oxygen content condition (6% when oxygen-depleted air is used);
- A high pressure condition (exceeding 2,500 pounds psi at the wellhead);
- A minimum flowing pressure of 1,000 psig; or
- A high temperature condition of 140 F or higher.

Based upon the results of the initial testing with oxygen-depleted air, a decision would be made on whether to proceed with testing utilizing ambient air. The Testing Operations Review Committee (TORC) was formed to assist in reviewing and analyzing the test data, comparing it against the predetermined criteria (outlined below), and making a recommendation on how/whether to proceed to the ambient air testing phase.

The TORC would utilize the criteria in Table 6-5 to analyze the results of the depleted air testing.

Table 6-5 Ambient Air Decision Criteria

	Criteria	**Result**	**Action**
CONFIRM	Measured methane concentration is less than 0.3% by volume (i.e., not more than 0.1% above modeled volume).	Data/results meet safety criteria.	TORC review, confirm, and provide recommendation to proceed with ambient air injection and withdrawal testing. Cease ambient air testing if methane concentrations reach 2% in withdrawal operations.
CAUTION	Measured methane concentration between 0.3% and 2.0% by volume of predicted volume. Rate of change in measured methane exceeds 0.2% per hour.	Result not in line with expectations based on modeling work.	TORC reviews and analyzes test data; may recommend additional modeling, additional oxygen-depleted testing, revisions to test procedures, or proceeding with ambient testing after concluding it is safe to proceed.
NO-GO	Measured methane concentration of 2% (50% of LEL).	Exceeds allowable content. Unsafe condition may exist.	TORC to review results; continue testing with oxygen-depleted air.

The TORC was an independent body made up of members with the following functional experience:

- Reservoir engineer
- Gas process engineer
- Gas facility operations engineer
- Safety specialist

The PCE and MHA will perform the data evaluation required and provide the results to the TORC for review. Data collected during the injection / withdrawal testing will be available daily to the PCE, MHA, and the TORC.

The TORC has the needed flexibility to:

1. Analyze all available data.
2. Adjust the test procedures if required to ensure the ongoing safety of the test; adjustments may include but are not be limited to:
    a. Adjustments to various parameters of the test such as flow rates, flow durations, and shut-in times to assist in controlling the methane concentration in the withdrawal stream.
    b. Adjustments to the monitoring methodology and instrumentation.
    c. Adjustments to the thresholds for alarms and emergency shut downs.
3. Request updates to the reservoir model by calibrating to the actual test performance data to assist with decision-making.

6.12 TSF PROCUREMENT

Once the decision was made to utilize oxygen-depleted air, the PCE developed a technical specification for the TSF to guide PG&E's procurement of the engineering, construction and operation of the TSF. The TSF was designed to support the primary and secondary test objectives. The design involved the coordination of three primary components as follows:

- Site preparation
- Injection / withdrawal well
- Compression equipment and balance of plant

The TSF site preparation consisted of the following tasks: road improvements and extension of the existing wellpad, subgrade preparation, and fill. The initial step in the site preparation was the generation of a Geotechnical Engineering Report. During creation of this report, specific information about the TSF soil properties were collected and analyzed to provide the appropriate design specifications for the pad extension and ultimately the installation of the TSF equipment. The PCE then utilized the results of the geotechnical report to create a site grading and drainage plan as the basis for the design of the road improvements and the pad expansion. The pad expansion in conjunction with the existing pad defined the site boundaries and served as the basis for access roads and foundation for all equipment and personnel.

The Injection / withdrawal test well (I/W Well) drilling and completion program was designed by the PCE and Irani Engineering in close conjunction with the storage reservoir team. The I/W well was designed to comply with the United States Environmental Protection Agency (EPA) Underground Injection Control (UIC) program/permit requirement and to flow the appropriate rates to support injection for the bubble build and withdrawal to simulate the expected CAES operation if the project was fully developed beyond this feasibility study. The I/W well is a directional well intended to be completed with a gravel packed liner in the Mokelumne River formation at an approximate depth of 4,770 feet.

The final components of the TSF design were the mechanical compression equipment and the overall design of the TSF, or the Balance of Plant engineering and supply. To accommodate all phases of the compression test, the program required equipment that would provide both high-pressure air and high-pressure nitrogen. The latter, as discussed above, was required as a safety precaution during the initial phases of the test against the creation of a potential flammable mixture during the withdrawal phase. During the procurement phase, PG&E was unable to find an EPC contractor willing to "wrap" the entire scope of the TSF work; therefore, the scope of the TSF was divided into two distinct components: 1) Air Nitrogen Injection Package (ANIP), which included the low-pressure (LP) and high-pressure (HP) compressors, nitrogen membranes, and related ancillary equipment, and 2) Balance of Plant (BOP) and Operations, which included overall engineering design, electrical, mechanical, and TSF operations.

The ANIP equipment required was directly a function of the test requirement to provide nitrogen. Nitrogen membranes will be utilized to generate the required nitrogen. The membranes operate at a maximum efficiency of 56% (maximizing the nitrogen produced per amount of compressed air provided) with an inlet pressure of 350 to 500 psig. This design parameter required the TSF be supplied with a combination of LP compressors, nitrogen membranes, and HP booster compressors. The nitrogen membranes and HP booster compressors were sized for the maximum test injection flow rate of 9,500 standard cubic feet per minute (SCFM). The LP compressors must provide enough compressed air for the maximum injection flow rate, plus account for the nitrogen membrane efficiency. Therefore the LP compressor must be able to deliver approximately 20,000 SCFM.

The overall design and engineering of the TSF was performed under the BOP contract with Bluewater Energy Services (BES). BES contracted with Stantec as the engineer of record for the BOP design. The function of the BOP design engineer was to integrate all other aspects of design into a cohesive engineering package as the basis of the design, construction, and operation of the TSF. This work requires inclusion of the geotechnical soils engineering, the grading and drainage plans, and the ANIP equipment.

During the BOP design engineering, Stantec utilized the required codes and standards as the basis of the design. When the basis for the engineering design was approximately 50% completed, a Hazard and Operability Study (HAZOP) was conducted (discussed in more detail below). This is when the safe operation of the plant was reviewed with the proper requirements incorporated into the TSF design. Additionally this was where any required environmental or permit conditions were incorporated into the design (such as the sound wall).

During the TSF BOP design, Stantec created the following engineering documents as the basis of the TSF design:

- TSF General Arrangement
- Piping and Instrument Diagrams
- Piping Isometrics
- Piping and Valve Specifications
- Mechanical Equipment Specifications (Test Separator and Silencer)
- PLC (Plant Control System) Logic Diagrams

- Electrical Single Line Diagrams
- Grounding Grid Plan
- Switchgear Specifications
- Electrical Specifications
- Foundation Plans

6.13 PROCESS HAZARD ANALYSIS (PHA) — HAZOP

To provide another review of the safety design of the TSF, a process hazard analysis (PHA) was conducted in accordance with all the mandatory PHA requirements for compliance with the U.S. OSHA Process Safety Management (PSM) Standard, 29 CFR 1910.119(e), issued in 1992. Different methodologies may be used to satisfy the OSHA's standard, depending on the stage of engineering design and information available. The selected and preferred methodology for the TSF was the Hazard and Operability Study (HAZOP), which was conducted upon completion of the Front End Engineering Design (FEED)—that is, at 50% engineering completion.

The approach to the HAZOP that was followed is described in *Guidelines for Hazard Evaluation Procedures*, 3rd Edition, Center for Chemical Process Safety (CCPS), 2008. The study assessed parameter deviations from normal design intent, deviations from operating procedures, equipment failure modes, identification of any previous incident that had the potential for catastrophic consequences, human factors and facility siting. Review of human factors and facility siting is described in Sections 8.5 and 8.6, respectively, of the CCPS guidelines book referenced above.

The process was divided into study segments, called nodes, to which guidewords or parametric deviations were applied. A PG&E Risk Matrix was provided to all of the PHA attendees as a guide in determining the risk levels. Each hazard was analyzed, documented, and if required, recommendations were assigned that would reduce or mitigate risk. Scenarios that constituted a hazard were ranked by the PHA team according to their estimated severity and likelihood of occurrence. Risk ranking was only applied to scenarios considered to have a credible potential for hazardous consequences.

The PHA team used five levels of severity to categorize each consequence based on degree of potential injury; severities were assigned to each consequence, assuming that the safeguard within the process did not respond as designed. The PHA team also used five levels of likelihood to categorize each hazard scenario. Likelihood was determined assuming that the safeguard within the process responded as designed. Safeguards reduce the likelihood of an incident from occurring or mitigate one that has happened.

Both the scenario severity and the scenario likelihood must be estimated in order to determine scenario risk. The severity and likelihood were considered jointly using a risk-ranking matrix to determine appropriate prioritization of the scenarios and associated recommendations. The risk ranking ranged from low to very high. A typical risk matrix is shown in Figure 6-22; the risk matrix and definitions for the severity and likelihood levels used in the PHA study are confidential to PG&E.

$$\textit{Scenario Severity} * \textit{Scenario Likelihood} = \textit{Scenario Risk}$$

The same risk estimation was used consistently in both the HAZID and HAZOP with the PHA team agreeing upon the severity and likelihood to evaluate scenario risk.

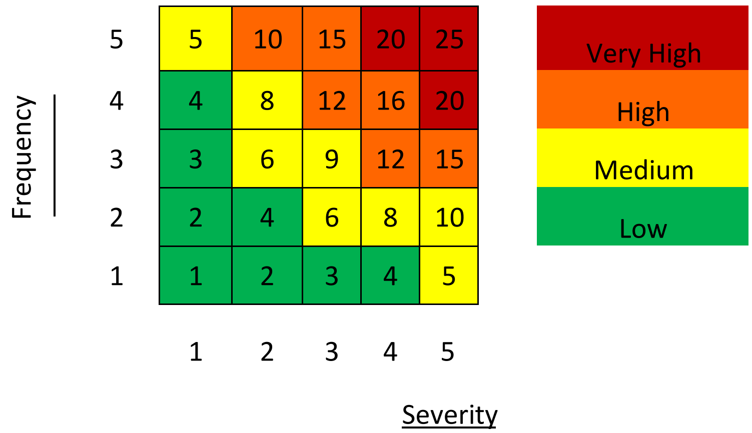


Figure 6-22 Typical Risk Matrix

6.13.1 Results of HAZOP

As a result of the HAZOP, 13 recommendations were made and implemented in the final engineering design and/or operating procedures. Table 6-6 provides a summary of the significant recommendations from the HAZOP (note: not all recommendations are listed):

Table 6-6 HAZOP Summary of Significant Recommendations

	Issue	Recommendation
1.	High-pressure releases could cause injury to employees in specific areas.	Create exclusionary zones around vents and equipment that restrict access; increase labeling/signage.
2.	Deviation during start-up procedure.	Develop a valve sequencing procedure for the manual and automatic valves to ensure safe start-up when initiating flow of injection gases.
3.	Methane and/or oxygen analyzer is out of service.	Three steps: 1) Install separate sample lines to the analyzers, 2) Configure analyzers so that at least one analyzer is always in service, and 3) Include analyzers in routine test and calibration program.
4.	Frac tanks could contain nitrogen or potential reactive chemicals.	Install sight glasses so employees can view level of frac tanks and not be exposed; install barriers and signs clearly restricting access to entry of frac tanks.
5.	Seismic event could cause damage to silencer and/or connected piping causing velocity impact hazard.	Perform seismic analysis on vent silencer. Provide structural support downstream of the test separator and piping to help protect against failure of or damage during a seismic event.

Note: Future tests and efforts, such as those described herein, should conduct their own Process Hazard Analysis (HAZID, HAZOP, or others as determined) and not rely on the results and recommendations of the HAZID or HAZOP for this project and its specific conditions.

A final sign-off by the engineering team, ANIP and BOP contractors, and PG&E was completed prior to starting operations to verify and document that the recommendations had been implemented.

6.14 PERMITTING: GENERAL APPROACH AND SCOPE

With the test objectives outlined in mind, the first order of business in concert with the design of the temporary facility required to perform the test, was to determine the various permits required and the various permitting activities necessary to gain these approvals.

Certain permitting activities during this project phase were able to benefit from the core drilling phase (see discussion in Chapter 6) in that previous environmental field studies and agency-approved Avoidance and Minimization Measures (AMMs) were utilized to a great extent. The scope of this phase included two distinct work activities based on the location and nature of the work: (a) construction of the electric distribution line to the site to power the electric compressor motors, and (b) construction of the temporary site facilities on King Island and subsequent air injection testing of the reservoir.

The electric distribution line work extended from PG&E’s Eight Mile Substation approximately 4.25 miles to the wellpad site on King Island. Work included the re-conductoring of existing line segments, construction of a new wood pole line, installation of a major transformer, and the vertical extension of the two lattice steel masts at the Bishop Cut crossing to provide the required navigation clearance.

The work at the King Island wellpad site included expansion of the pad developed for core well drilling, mobilization and demobilization of the compression and support equipment, drilling of the injection / withdrawal well, and compression testing operations.

6.14.1 Permitting Jurisdictions

A combination of federal, state, and local permits are typically required for this type of activity. This section provides a discussion of the applicability of the permits required to support this phase of the project.

Federal

Since the CAES project was partially funded by the federal Department of Energy (DOE), the DOE was required to comply with environmental procedures under the National Environmental Policy Act (NEPA).

1. For the electric distribution line work, the DOE prepared an Environmental Questionnaire and issued an Interim Action Memo (IAM) that confirmed the electric distribution upgrade activity would not have an adverse environmental impact nor limit the choice of reasonable alternatives for the project.

To support the DOE's IAM determination, biological and cultural resource surveys were completed along the electric distribution line route, and consultation was initiated with the US Fish and Wildlife Service (USFWS) under Section 7 of the Endangered Species Act and with the California State Historic Preservation Office (SHPO) under Section 106 of the Historic Preservation Act. The USFWS concurred the project, with the specified Avoidance and Minimization Measures (AMMs), would not adversely affect federally listed species. The SHPO concurred with DOE's determination that no historic properties would be affected by the electric distribution line work. Consultation with local Native American tribes resulted in an agreement to monitor, at tribe-selected pole locations, the augering work for the electric line construction. No cultural resources were discovered during augering at the selected pole locations.

2. For the proposed activities at King Island, NEPA compliance consisted of preparation and approval of an Environmental Assessment (EA) and Finding of No Significant Impact (FONSI). This process included a public notice and 35-day review and comment period that concluded on December 31, 2013.

   In addition to compliance with NEPA, DOE completed consultations under Section 7 with the USFWS and Section 106 with SHPO. To support DOE compliance with these two resource-specific laws, field surveys were conducted of the potential impact areas at King Island not previously surveyed for the core well drilling phase, and biological and cultural resource reports were prepared addressing potential impacts to these resources. The reports prescribed AMMs as part of the project design, most of which were previously approved by the resource agencies and implemented for the core well drilling. The biological reports were used to formally consult with the USFWS regarding potential impacts to federally listed species. The USFWS concurred that the project is not likely to adversely affect federally listed species. The cultural resource reports were used to consult with the SHPO who concurred the project would not affect historic resources. Consultation with the Native American tribes resulted in an agreement to conduct shovel testing at the well pad expansion area and prepare an ethnographic study. No cultural resources were found during this testing.

   The EA, its appendices (which include the above referenced biological and cultural reports) and the FONSI are located at the links identified below.

   http://www.netl.doe.gov/File%20Library/Library/Environmental%20Assessments/PG-E_CAES_Concurrence_Final-EA_04-30-2014.pdf

   http://www.netl.doe.gov/File%20Library/Library/Environmental%20Assessments/PGE_CAES_Concurrence_FEA_Appendix_04-30-2014_complete.pdf

   http://www.netl.doe.gov/File%20Library/Library/Environmental%20Assessments/5-15-14-signed-PGE-FONSI.pdf

3. In addition to complying with NEPA, the other key federal permit required for project implementation was the US Environmental Protection Agency (EPA) Underground Injection Control (UIC) well drilling and injection permit. The UIC program is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. In 1974, Congress passed the Safe Drinking Water Act (SDWA). Part of the SDWA required EPA to report back to Congress on waste disposal practices, and to develop minimum federal requirements for injection practices that protect public health by preventing injection wells from contaminating underground sources of drinking water (USDWs).

   A USDW is an aquifer or part of an aquifer that is currently used as a drinking water source or may be needed as a drinking water source in the future. Specifically, a USDW:

   - Supplied any public water system, or
   - Contains a sufficient quantity of ground water to supply a public water system, and
     - Currently supplies drinking water for human consumption, or
     - Contains fewer than 10,000 mg/l total dissolved solids (TDS), and
   - Is not an exempted aquifer

   The UIC program protects USDWs from endangerment by setting minimum requirements for injection wells. All injection wells must be authorized under either general rules or specific permits. Injection well owners and operators may not site, construct, operate, maintain, convert, plug, abandon or conduct any other injection activity that endangers USDWs. The purpose of the UIC requirements is to:

   - Ensure that injected fluids stay within the well and the intended injection zone, or
   - Mandate that fluids that are directly or indirectly injected into a USDW do not cause a public water system to violate drinking water standards or otherwise adversely affect public health.

   Specific requirements are found in Title 40 of the Code of Federal Regulations. The Ground Water Office of EPA Region IX based in San Francisco was responsible for processing and administering the UIC permit for this study.

   PG&E's application, its final UIC permit issued on August 20, 2014, and other related documents can be found at the following link:

   http://www.epa.gov/region09/water/groundwater/uic-permits.html#pge-caes

State

The three state agencies with jurisdiction over some aspect of the proposed TSF and air injection testing activities include the Division of Oil, Gas & Geothermal Resources (DOGGR), California Department of Fish and Wildlife (CDFW), and the California Regional Water Quality Control

Board (RWQCB). A description of the permitting requirements of each agency is described below.

DOGGR

DOGGR regulates all gas and oil well activities in the state. A key role of the agency is to establish "Field Rules" for well drilling and well operation/maintenance for each natural gas field (see the "Reservoir Screening and Site Identification" chapter for a definition of Field Rules). Field Rules may expire after a gas field has been depleted and production discontinued. Where field rules are still active, issuance of a well drilling permit is considered ministerial. However, where field rules must be re-established, DOGGR must conduct an environmental review of proposed new field rules and drilling activity under the California Environmental Quality Act (CEQA). The King Island site had active field rules; thus the issuance of well drilling permit was considered ministerial.

CDFW

CDFW manages the state's fish and wildlife resources, including species that are protected as threatened or endangered under state law. To ensure the project activities did not result in impact to state-listed species, the biological studies prepared for submission to DOE included all state-listed species, as well as any other sensitive species of concern to CDFW. Appropriate AMMs were included in the biological report to address any potential impacts to these species. Since the project would not adversely affect any state-listed threatened or endangered species, no CDWF approvals were required, but agency staff coordinated with the USFWS during the DOE Section 7 consultation and monitored the DOE NEPA process.

RWQCB

RWQCB manages the federal National Pollution Discharge Elimination System (NPDES) program in California and has prepared regulations for addressing Construction Storm Water runoff from sites greater than one acre. A Notice of Intent (NOI) to secure coverage under this permit was filed and WDID#: 5S39C367809 was issued by the RWQCB for the project. A comprehensive Storm Water Pollution Prevention Plan was prepared and implemented for both the electric distribution line work and the work at King Island.

Local/Regional

As a regulated public utility, PG&E's activities are subject to the sole jurisdiction of the California Public Utilities Commission (CPUC). As such, the CPUC pre-empts local <u>discretionary</u> land-use approval authority, but requires utilities to obtain local <u>ministerial</u> permits.

San Joaquin County requires approval of a ministerial Improvement Plan for Oil and Gas well facilities. The objective of this Improvement Plan is to ensure the well drilling activity does not affect adjacent land owners or uses (noise, light and glare), and that the activity complies with other county engineering and safety ordinances (site development, hazardous materials, and fire safety). As long as the standard permit conditions for gas well drilling and site restoration can be met and are agreed to by the applicant, the permit is issued. An Improvement Plan was approved for the core drilling phase at King Island, and the county determined subsequent approval for the injection and withdrawal well associated with the Compression Testing Phase was not required.

A condition of the Improvement Plan approval was to obtain an Operational Fire Permit from the County Fire Prevention Bureau. Permit FP-1300001 was approved by the Woodbridge Fire District and issued by the Bureau.

The other local agencies with jurisdiction over the proposed air injection phase were the local Reclamation Districts, which are responsible for maintaining selected levees in the Sacramento – San Joaquin River Delta. An encroachment permit was obtained for the use of the road on the top of King Island levee for project vehicle access, with the objective of ensuring the road impacts resulting from the use by project vehicles would be mitigated.

Due to the potential to release air emissions during construction and testing, the air injection phase came under the jurisdiction of the San Joaquin Valley Air Pollution Control District (SJVAPCD). SJVAPCD develops, plans, and implements control measures for stationary sources in its control area, which includes the project site. Given the potential to be an emissions source, this phase of the project was required to either obtain permits under Rule 2010 (Authority to Construct and Permit to Operate) or to seek an exemption under Rule 2021.

PG&E elected to pursue the exemption, which consisted of demonstrating compliance with the following criteria:

- Purpose of the operation is to permit investigation, experimentation or research to advance the state of knowledge or the state of art of a particular (emissions reducing) industrial process.
- SJVAPCD shall be notified, in writing, of the purpose, goals, and objectives of the project, measures to be taken to minimize the emission of air contaminants, the proposed installation date, the planned start-up date, the expected duration of the test, and test schedules.
- Amount and duration of emissions shall be minimized as determined by SJVAPCD.
- Cumulative total days of operation shall not exceed 180 calendar days.

In addition, since this project phase involved construction, excavation and related earthmoving activities, it was required to comply with District Rule 8021, which relates to limiting fugitive dust emissions. In conjunction with this rule, PG&E was also required to provide written notification to the District at least 48 hours prior to commencing earthmoving activities. Since the disturbed area was less than 5 acres, the project was not required to submit a Dust Control Plan, although one was developed and implemented as a standard practice.

6.15 TSF CONSTRUCTION AND OPERATIONS

6.15.1 TSF Construction

PG&E constructed the TSF based on the design created by Stantec Engineering under direction of Bluewater Energy Services (BES). At the 50% design point, the project team performed a HAZOP, as described in Section 6.13. All major project participants attended the HAZOP and were required to sign off on the final HAZOP implementation plan; the implementation plan presented the TSF design response to the 13 initiatives identified in the HAZOP.

A design challenge specific to the TSF was the utilization of leased or rental equipment for the preponderance of the major equipment. This challenge resulted in selecting the best equipment available for the process design during the procurement phase. It also added the unique challenge of interfacing portions of the plant without complete design details.

The design basis is depicted on the following key Stantec drawings:

- General Arrangement: M00 01 001, Rev 0 (Figure 6-26)
- One Line Diagram: E00 02 001, Rev 0 (Figure 6-27)
- P&ID – Injection: P00 02 001 Rev 1 (Figure 6-28)
- P&ID – Withdrawal: P00 02 001 Rev 1 (Figure 6-29)

Construction was completed in phases with distinct scope and contractor responsibilities. The phased construction was planned to minimize the cost associated with leased equipment; equipment contracts were structured so that the equipment was not eligible for payments until the equipment was on site and ready for operation. The following are the construction phases, contractors, and the timing of their site construction activities:

- Site pad preparation: Ahtna – July to September 2014
- I/W Well Construction: Irani Engineering / Paul Graham Drilling – October and November 2014
- Air Nitrogen Injection Package (ANIP) equipment installation: Generon ICS – January to March 2015
- Balance-of-plant installation: Bluewater Energy Services (BES) – July 2014 to February 2015

Site Pad Preparation

Site pad preparation began with the removal of the remaining orchard trees from the approximately 2.7-acre site (an approximately 1.0 acre well pad already existed and was expanded by an additional 1.7 acres to accommodate the equipment required for the air injection test). This tree removal was followed by clearing and grubbing the site and establishing the design sub-grade elevation. At this point Ahtna turned the site over to BES for installation of the TSF underground grounding grid.

Once the underground grounding grid was installed, Ahtna then installed sub-surface geo-textile fabric and imported the required 18 to 24 inches of Class II aggregate road base. The pad material was compacted to 95% and finish-graded to provide proper site drainage (Figure 6-23).

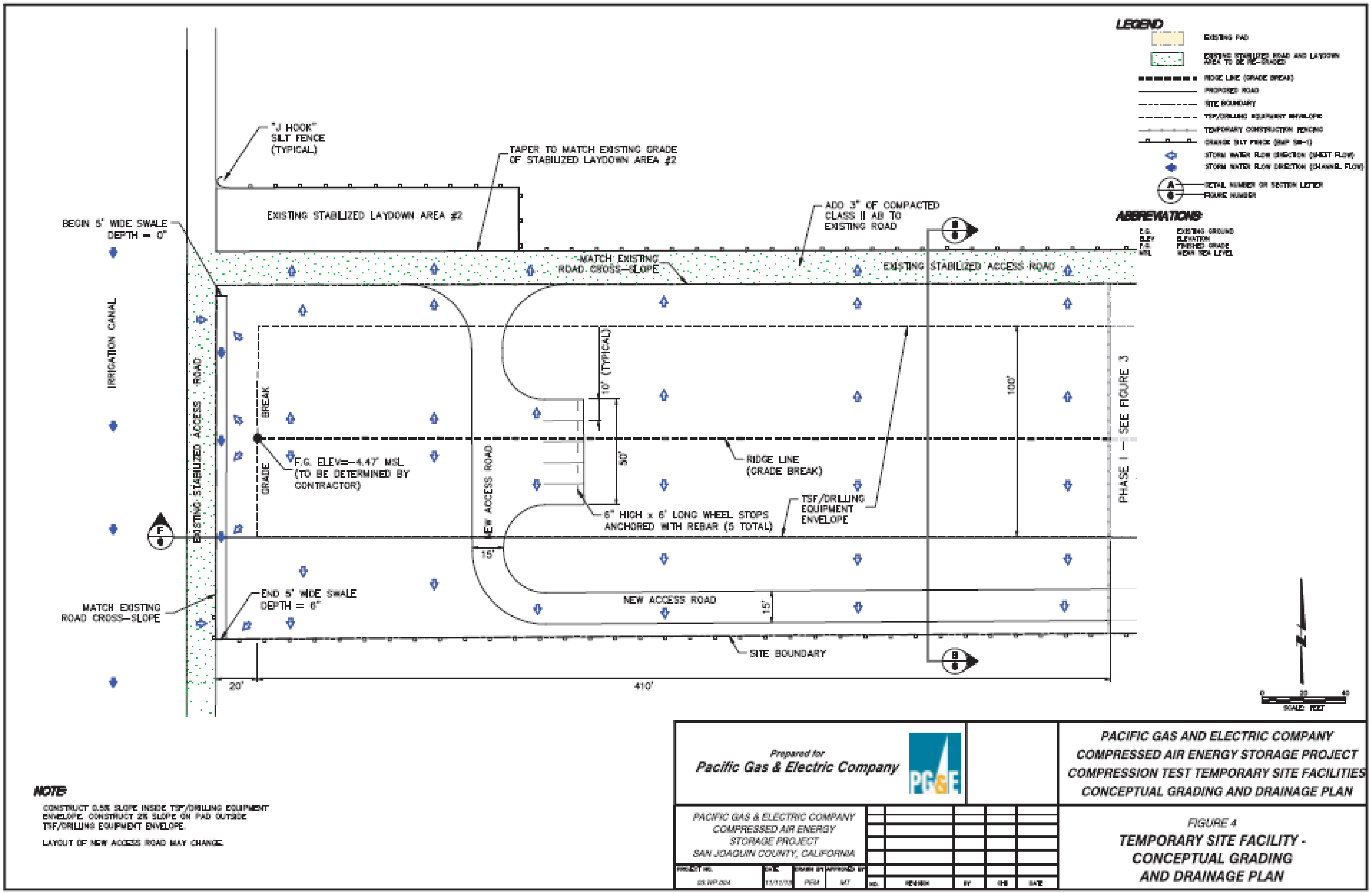


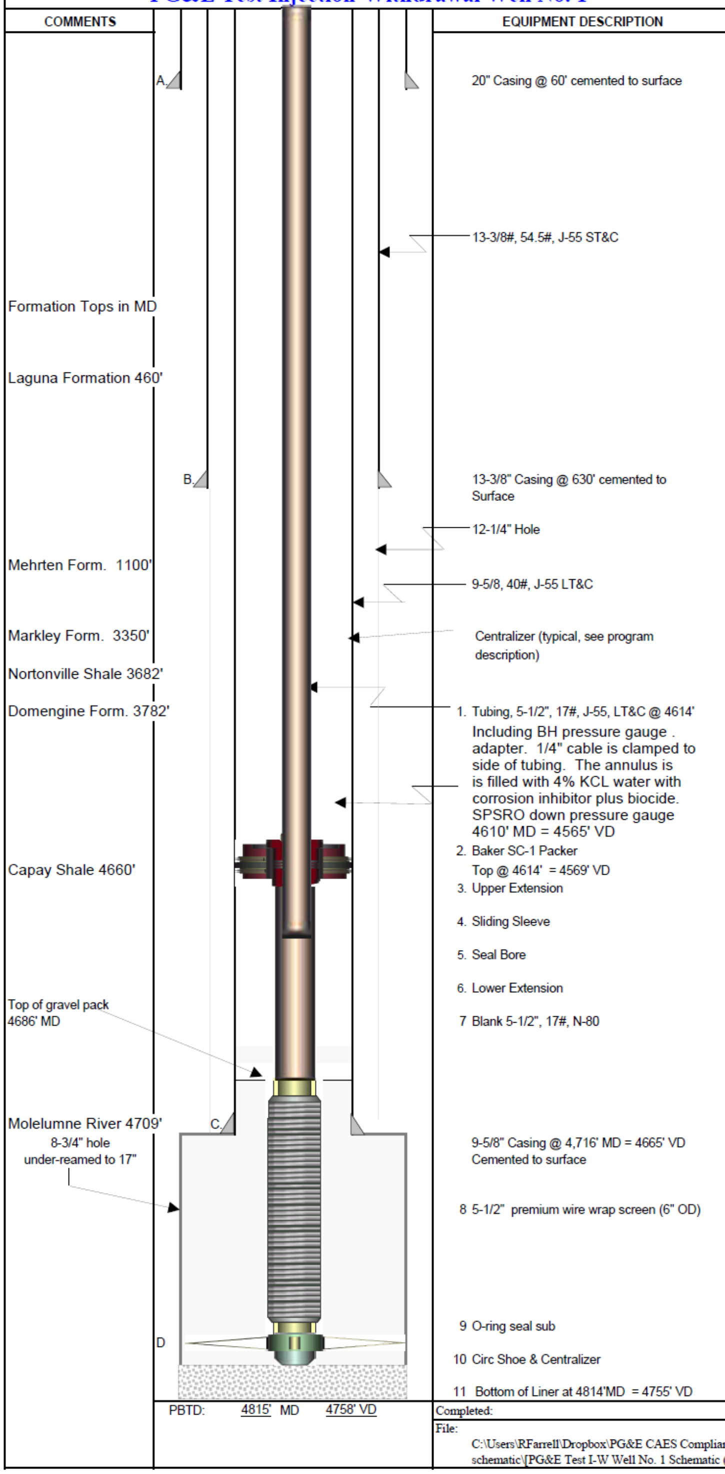
Figure 6-23 TSF Conceptual Grading and Drainage Plan

I/W Well Construction

A permit was received from the EPA for drilling the PG&E Test Injection / withdrawal Well 1 on August 20, 2014 (Permit No. R9UIC-CA5-FY13-1). Drilling operations for the PG&E Test Injection / withdrawal Well 1 commenced on October 9, 2014 and were completed on November 4, 2014. Well completion operations to install the 5 ½-inch tubing with the downhole pressure gauge were concluded on November 26, 2014. The well was directionally drilled to a total measured depth (MD) of 4,963 feet and a true vertical depth (TVD) of 4,900 feet. The top of the objective Mokelumne River Formation (MRF) was encountered at 4,709 feet MD (4,658 feet TVD).

The well was completed with 13 3/8-inch casing cemented to the surface at 630 feet, and 9 5/8-inch casing set at 4,716 feet MD and cemented to the surface. The MRF completion zone of 4,709 to 4,815 feet was under-reamed to a diameter of 17 inches, a 5 ½-inch premium wire-wrapped screen was installed from 4,686 to 4,814 feet, and the annulus between the screen and the formation was gravel-packed with 184 cubic feet of 20/40 sand. After gravel-packing operations were complete, 4,614 feet of 5 ½-inch tubing was installed with a packer assembly to isolate the annulus between the tubing and well casing. A schematic of the wellbore is provided in Figure 6-24.

PG&E Test Injection-Withdrawal Well No. 1



PG&E
WELL COMPLETION DIAGRAM

FIELD	NA
WELL #	PG&E Test Injection/Withdrawal Well No. 1
Ground MSL -6	-3.75
KB	8.25'
LOCATION	Sec. 27, T 3N, R 5E, MDB&M

DIRECTIONAL DATA

MAX ANGLE	20	THRU ZONE	4815'
KOP	3490'	HOLE TYPE	Directional
4703			

SURFACE EQUIPMENT

TREE	5-1/8" 3M
SWAB CAP SIZE & THRD	9" 4P Acme Thread
TOP TREE FLANGE	5-1/8" 3M
TUBING SPOOL FLANGE	11" 3M

TUBING DETAIL

	1st or LS	SS or Btm of Taper
SIZE	5-1/2"	
WEIGHT	17#	
GRADE	J-55	
DEPTH	4614'	
THREAD	LT&C	
NEW/USED	NEW	
COATING	None	
SCSSV	None	
Min. I.D.	4.667"	

	O. D. (in.)	I. D. (in.)	LENGTH (ft)	DESCRIPTION
1.	5-1/2"	4.767"	4614'	5-1/2", 17#, J-55
2.	8.6"	6"	4.56'	Baker SC-1 Packer
3.	7.63"	6.969"	5.99'	7-5/8", 26#.Upper Extension
4.	8.13"	6"	2.12'	Baker Model S Sliding Sleeve
5.	7.63"	6"	1.7'	Baker Seal Bore
6.	7"	6.366"	19.63'	Lower Extension
7.	5.5"	4.892"	38.30'	Blank 5-1/2", 17#, N-80
8.	6"	4.892"	122.68'	51/2" Wire wraped screen
9.	5.5"	3.5"	2.63'	O-ring seal sub
10.	5.5"	N/A	1.9'	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' - 630'
C	9-5/8""	40#	J&N	LT&C	0' - 4,716'
D	5-1/2"	17#	N-80	LT&C	4614'-4815'
E	6"	17#	N-80	LT&C	Liner from 4686' to
F					4814'
G					
H					
I					
J					
K					
L					
M					
N					

Prepared By:	Saeed Irani	Date	January 19, 2015
Updated By:	Saeed Irani	Date	January 19, 2015
		Printed on	January 28, 2015

Completed:
File:
C:\Users\RFarrell\Dropbox\PG&E CAES Compliance\Well Completion Report\Phase III\Comment Response\6. IW well schematic\[PG&E Test I-W Well No. 1 Schematic (8).xls]Actual WBD

Figure 6-24 I/W Well Schematic

Because of the unique purpose of this well and the extensive injection and withdrawal testing to be conducted, a downhole pressure gauge was installed with a hardwired cable to the surface. The gauge housing was installed just above the packer at 4,610 feet MD (4,565 feet TVD) and connected to the surface by a ¼-inch cable strapped to the outside of the 5 ½-inch tubing. The wellhead was modified to provide routing of the cable to a surface control box for access to the data from the downhole gauge.

Observation Wells

Two observation wells were utilized to gather additional reservoir information during the testing phase. The Piacentine #1-27 well was a gas-producing well that was modified for this purpose. A downhole packer was installed on the existing 2-3/8-inch tubing at a depth of 4,650 feet to isolate the annulus from the storage formation. Pressures were monitored at the wellhead for both the tubing and annulus. Periodically, bottomhole pressure and temperature surveys were taken to confirm actual reservoir conditions at the location of the well.

The project also utilized the previously drilled core well, the Piacentine #2-27 (see Chapter 5, "Core Drilling, Completion, Logging and Analysis"), as an observation well. Casing had been installed in this well after conclusion of the previous coring operation; however, the casing was not perforated, preventing the wellbore from communicating with the reservoir. Rather, the project team decided to periodically run thermal-decay-cased hole logs in the well to analyze the water saturation in the reservoir near the wellbore.

A sketch of the relative location of the observation wells to the I/W well is provided in Figure 6-25. This figure depicts the distance from each observation well to the I/W well at the depth of the Mokelumne River formation, which is approximately 180 feet for the Piacentine #1-27 well, and 360 feet for the Piacentine #2-27 well.

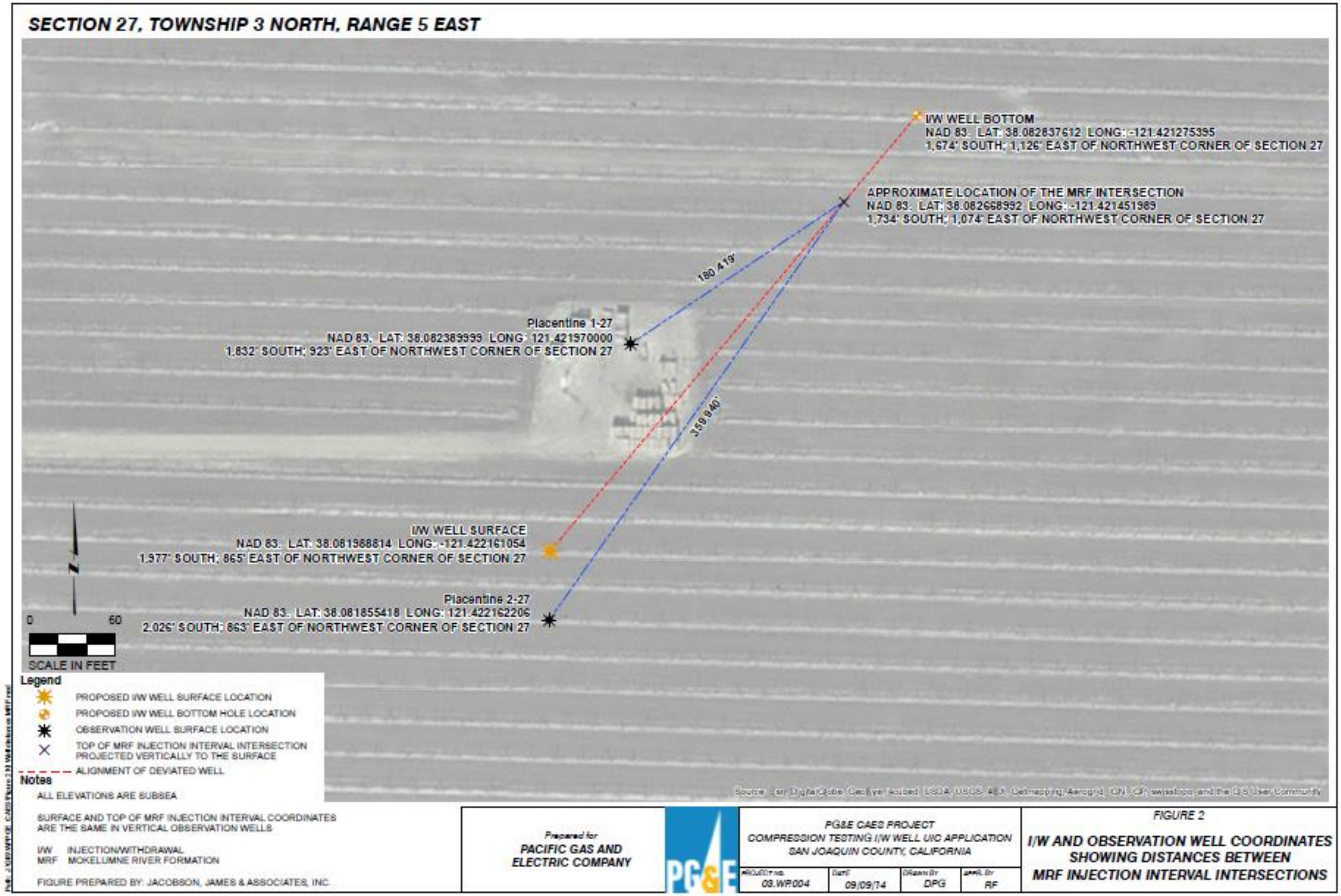


Figure 6-25 Observation Wells in Relation to I/W Well

ANIP Equipment Installation

Generon was selected to supply the Air Nitrogen Injection Package (ANIP) equipment. All of the ANIP equipment was leased for the test period and therefore was constructed to be installed on a temporary basis. All equipment was stand-alone for installation without a foundation and any underground utilities. Also each piece of equipment was self-contained with all required controls and instrumentation for safe operation and shutdown.

The ANIP equipment consisted of the following:

- 5 LP compressors with a 350-psig discharge pressure
- 5 Air-cooled after-coolers for the low-pressure (LP) compressor discharge cooling
- 4 Demister tanks
- 2 Fin fan cooling units for the LP compressors
- 5 nitrogen processing units (NPU)
- 5 high-pressure (HP) booster compressors with a maximum discharge pressure of 2512 psig
- Required tanks, air-driven pumps, and hoses for the removal, collection, and storage of discharge condensate
- Interconnecting low- and high-pressure hoses for the installation of all equipment
- Start-up vent silencers and protective relief devices
- Motor starters and control systems for all equipment

Generon delivered all of their equipment to the TSF and set the equipment in the locations determined by the Bluewater design, shown in Figure 6-26. Generon's technicians mechanically connected all of their equipment; DL Payne (Bluewater's electrical subcontractor) provided all of the electrical connections to cables that had been installed prior to the arrival of the ANIP equipment, as depicted in Figure 6-27. The LP compressors and NPUs arrived on site ready for operation following typical commissioning by Generon's technicians The LP compressors required final alignment and extensive tuning by ICS (third-party vendor). The time required to prepare the LP compressors ultimately delayed the test and determined the final test schedule and duration.

Generon was responsible for the high-pressure discharge hose and connection to the balance-of-plant piping terminal point; the terminal point is in the lower right corner of Figure 6-28 and has the reference "Injection Gas from ANIP."

Balance-of-Plant Installation

Bluewater Energy Services (BES) was contracted to provide the balance-of-plant supply and construction of the TSF. BES acted as the prime contractor. Procurement of all required balance-of-plant equipment and materials was by BES or Stantec. BES utilized the following major subcontractors for their respective disciplines:

- Engineering: Stantec
- Electrical: DL Payne
- Electrical Switchgear: Belyea – Equipment supply only

- Mechanical: Bayview Mechanical
- Noise Control – ArtUSA Noise Control

BES constructed the TSF in phases to support their equipment deliveries and the delivery of the major ANIP equipment, which was planned for just-in-time arrival prior to the start of the test. Additionally, the construction philosophy was unique for the TSF in that the installation had to meet all required safe practices and codes, but was intended for only four months of service after which it would be demolished.

Electrical Installation

Following the delivery of the Belyea electrical transformers and switchgear, DL Payne tested each piece of equipment. The transformers and switchgear were then installed on wooden cribbing. DL Payne constructed a series of cable trays that traversed the site to all locations for equipment, as designed on the TSF General Arrangement and the One-Line Diagram (respectively Figures 6-26 and 6-27). Cables sized for each service were installed in the tray to be terminated once the equipment arrived.

Mechanical Installation

Bayview Mechanical completed all the piping and mechanical equipment installation for BES. Their work included the only two concrete foundations installed on site—for the test separator and the vent silencer. Their piping was all installed and tested per ANSI B31.1; this piping provided the BES interface to both the ANIP equipment and the I/W well for injection and withdrawal.

Due to very stringent noise requirements from the TSF permits, a sound wall was constructed on the west and south sides of the site. This wall was installed by ArtUSA Noise Control and consisted of a series of steel columns and fabric sound blankets that could be removed to work on or move equipment.

Controls

All of the TSF instrumentation indicated on the piping and instrumentation diagrams (P&IDs) (Figures 6-28 and 6-29) was installed by BES subcontractors.

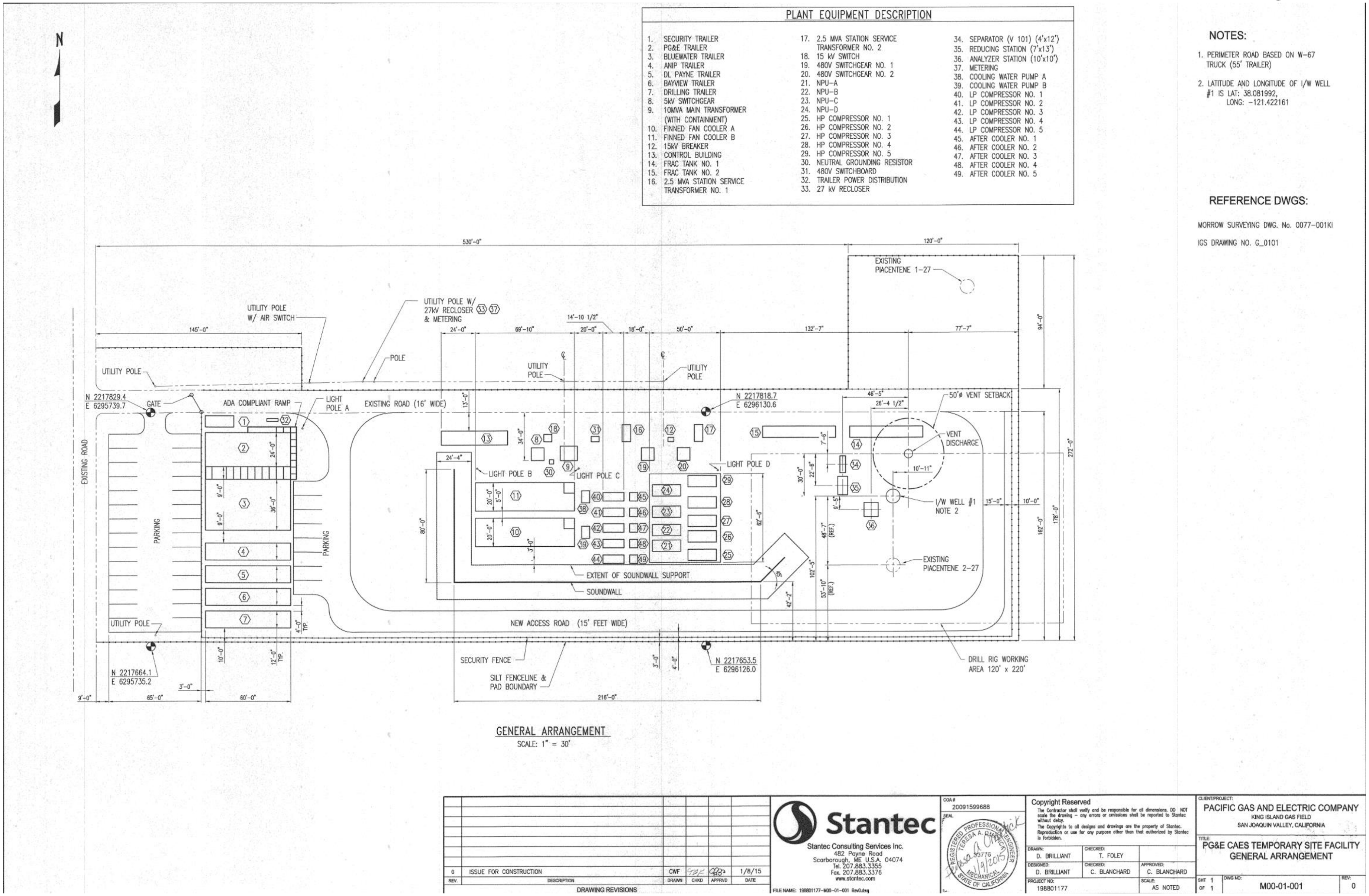


Figure 6-26 General Arrangement of Equipment for the Temporary Site Facility (TSF)

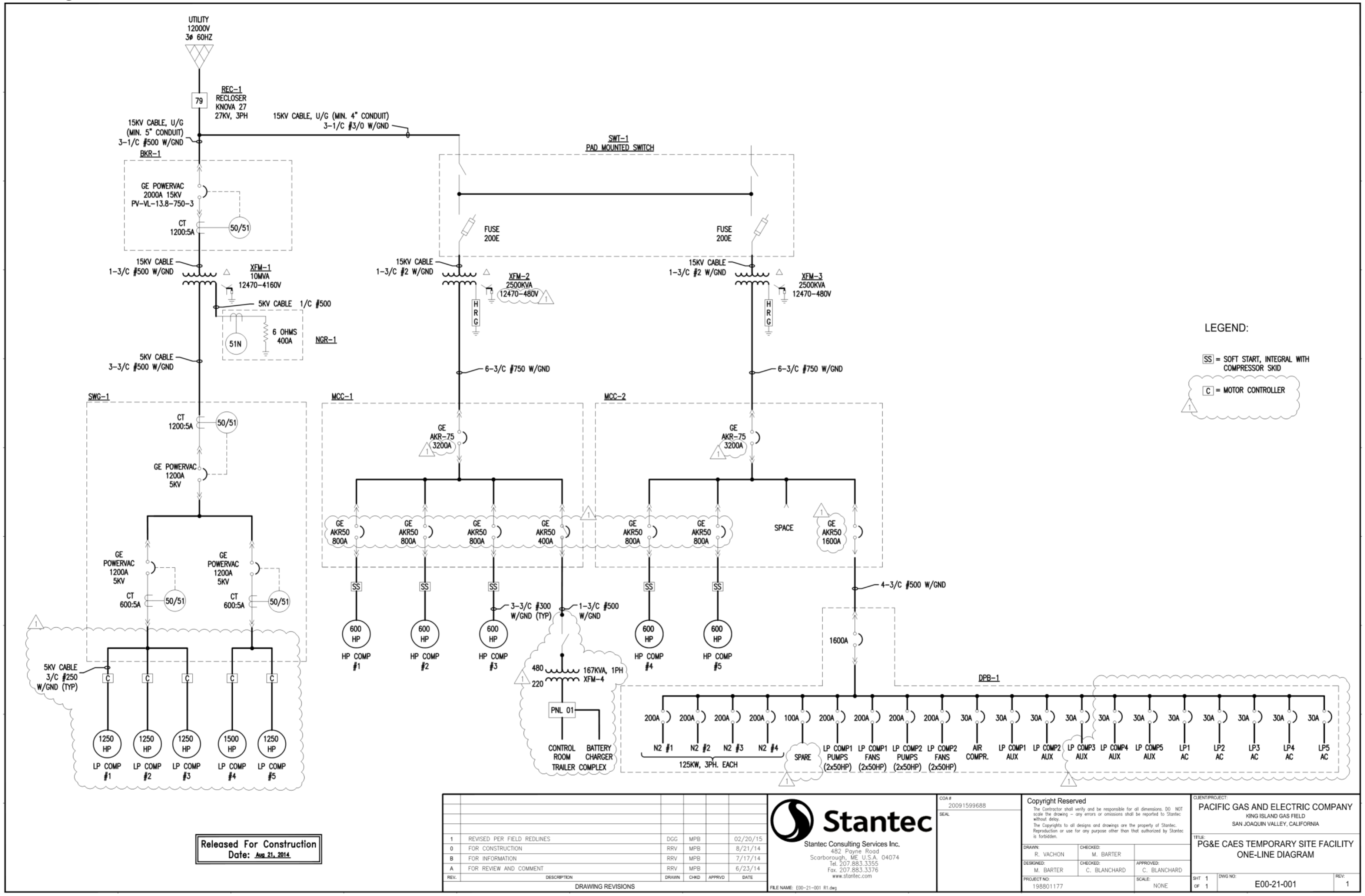


Figure 6-27 One-Line Diagram of Electrical Connections at TSF

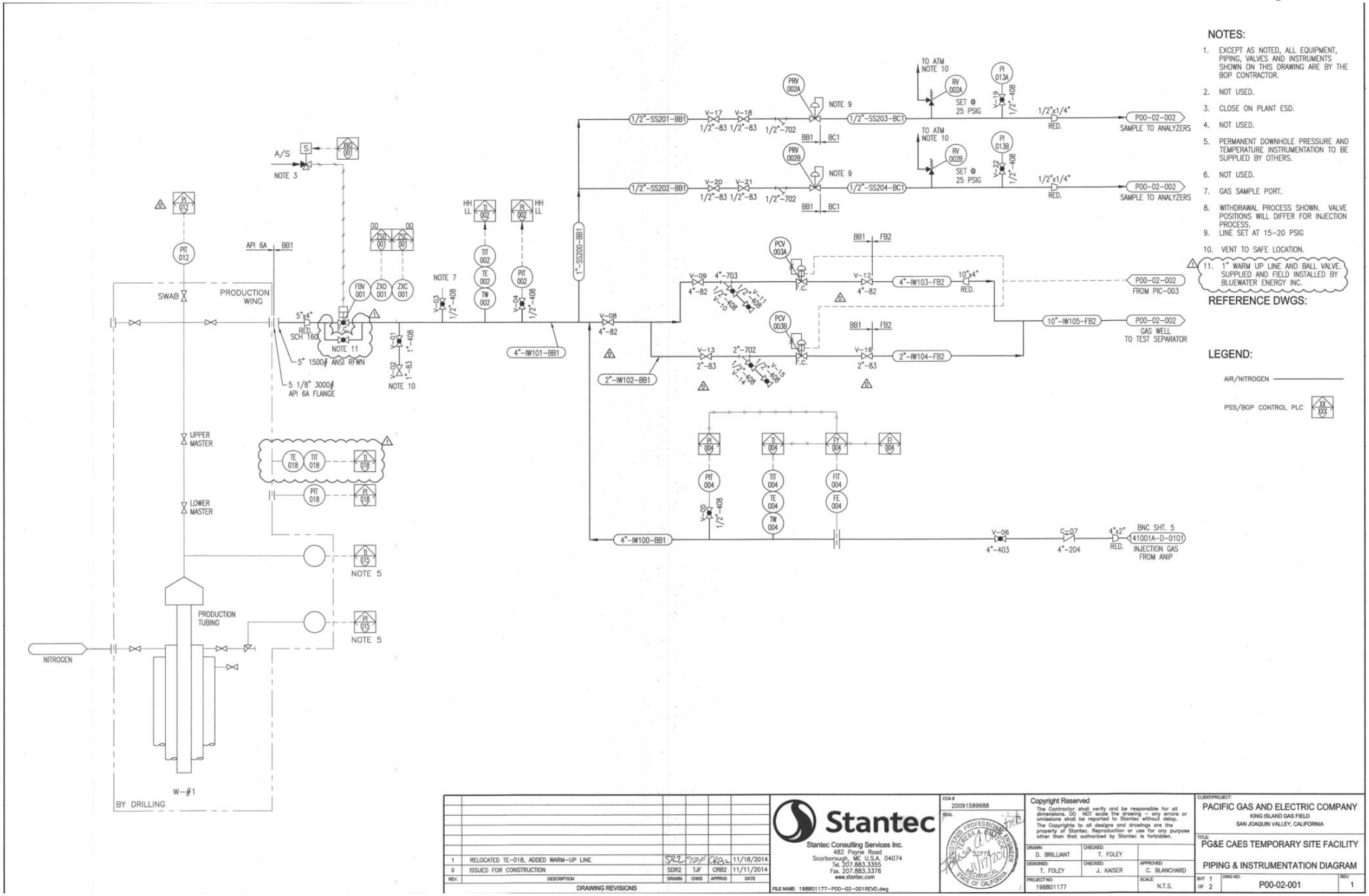


Figure 6-28 Piping and Instrumentation Diagram (P&ID) – Injection Diagram at TSF

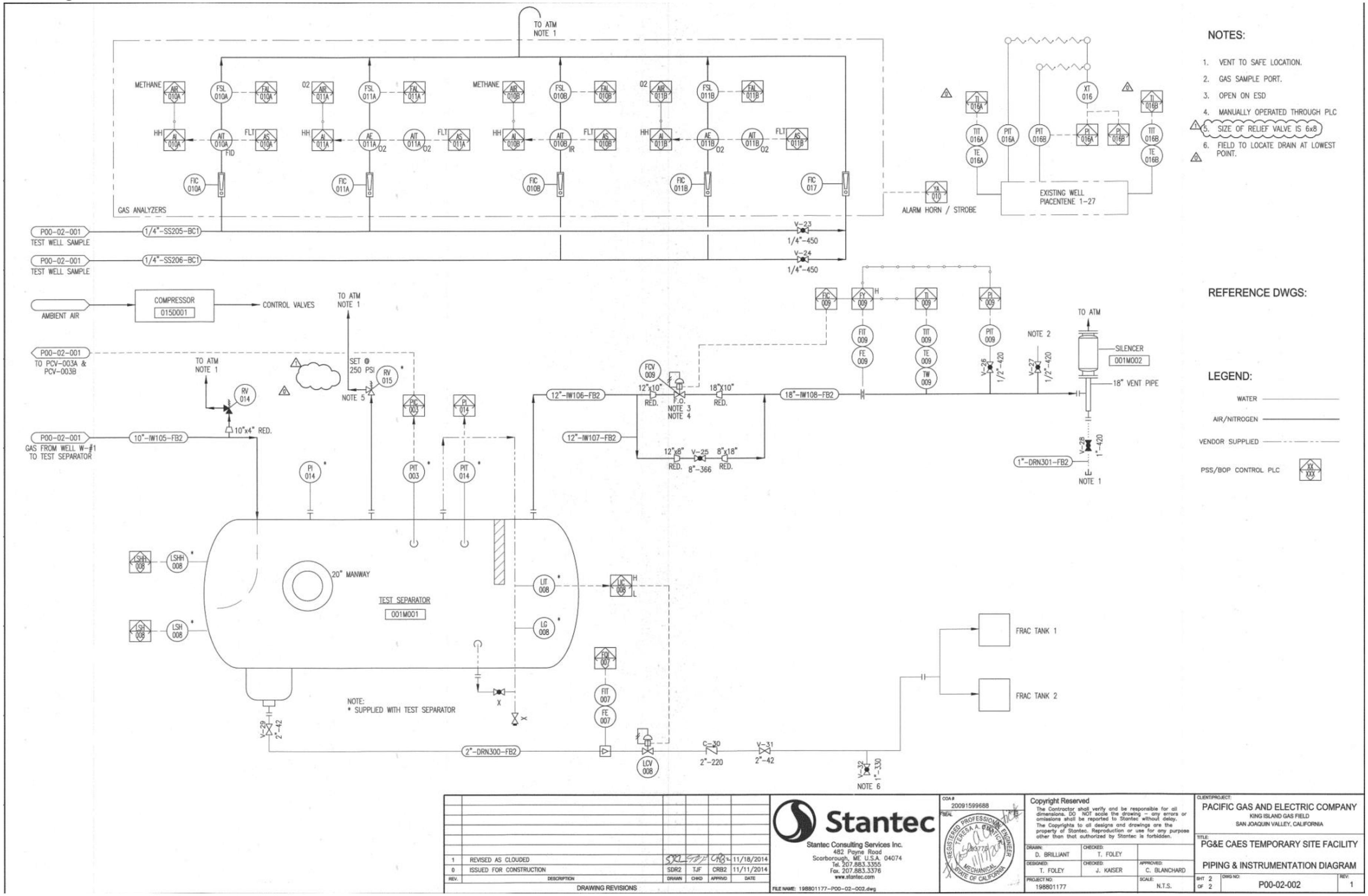


Figure 6-29 Piping and Instrumentation Diagram (P&ID) – Withdrawal Diagram at TSF

The instruments were then calibrated by PG&E instrument technicians, per the specifications shown in Table 6-7. The instrumentation provided in the TSF was for the safe operation and monitoring of the plant, to collect the information required to analyze the performance of the reservoir, and to provide the information required to support the decision matrix discussed in Section 6.11 to transition from injecting oxygen-depleted air to injecting ambient air into the I/W well.

Table 6-7 TSF Instrumentation Specifications

Location	Equipment	Instrument Type	Manufacturer / Model	Accuracy	Operating Limits[1]	Stability
I/W Well Downhole (with surface read-out)	Downhole Press/Temp Sensors	Piezoresistive Pressure Transducer	Tendeka SPSRO P/T Quartz Tag No. 00-PT-015	0.02% full scale	500-10,000 psi	<0.02% full scale per year
		Platinum Wire RTD	Tendeka SPSRO P/T Quartz Tag No. 00-TT-015	± 045°F	77-350°F	--
Piacentine 1-27 and Citizen Green 1 Downhole[4]	Suspended Press/Temp Sensors	Hybrid quartz crystal sensor	Metrolog CGM5	± 0.02%	0-15,000 up to 0-30,000 psi	--
				± 0.3°F	0-302 °F	--
I/W Well Wellhead	Press Sensor at tubing head and annulus	Absolute Pressure	Rosemount 3051S2CA4A2A11A1AE5Q4 Tag No. 00-PIT-012 (tubing head) Tag No. 00-PIT-018 (annulus)	± 0.03% of span	0-3,000 psi	± 0.15% of reading for 24 months
	Temp element and transmitter at tubing head	Thermocouple	Pyromation R1T185L483-(TW)-SL-8HN31 Tag No. 00-TE-002 Rosemount 3144PD1A1E5M5Q4 Tag No. 00-TIT-002	± 0.02% of span	0-120°F (transmitter)	± 0.1% of reading for 24 months
	Temp element and transmitter at annulus	Thermocouple	Omega SA1-RTD-4W-120 Tag. No. TE-018 Rosemount 648DX1D1I5WASWK1M5Q 4F6B5 Tag No. TIT-018	± 0.06%	-100-500°F (element) 0-120°F (transmitter)	<0.2% per year
Piacentine 1-27 Wellhead	Press Sensors at tubing head and annulus	Absolute Pressure	Rosemount 3051S2CA4A2A11X5AWA3 WK1I5M5Q4, 701PBKKF Tag No. 00-PIT-016A, 016B	± 0.03% of span	0-3,000 psi	± 0.15% of reading for 24 months
	Temp element and transmitter at tubing head	Thermocouple	Omega SA1-RTD-4W-120 Tag. No. TE-016A Rosemount 648DX1D1I5WASWK1M5Q 4F6B5 Tag No. TIT-016[a]	± 0.06%	-100-500°F (element) 0-120°F (transmitter)	<0.2% per year
	Temp element and transmitter at annulus	Thermocouple	Omega SA1-RTD-4W-120 Tag. No. TE-016B Rosemount 648DX1D1I5WASWK1M5Q 4F6B5 Tag No. TIT-016B	± 0.06%	-100-500°F (element) 0-120°F (transmitter)	<0.2% per year
Citizen Green 1 Wellhead	Press Sensor at tubing head	Pressure	Barton Model 202A-2000	0.5% full scale	0 – 2000 psi	--
Injection Pipe near	Injection Gas Press/Temp /Flow	Differential Pressure Flow	Rosemount 3051S2CD2A2A11A1AE5Q4 Tag No. 01-FIT-004	± 0.03% of span	0-100 inches water column	± 0.15% of reading for 24 months

Location	Equipment	Instrument Type	Manufacturer / Model	Accuracy	Operating Limits[1]	Stability
I/W Well Manifold		Absolute Pressure	Rosemount 3051S2CA4A2A11A1AE5Q4 Tag No. 01-PIT-004	± 0.03% of span	0-3,000 psi	± 0.15% of reading for 24 months
		Thermocouple	Pyromation R1T185L483-(TW)-SL-8HN31 Tag No. 01-TE-004 Rosemount 3144PD1A1EM5Q45 Tag No. 01-TIT-004	± 0.02% of span	0-120°F (transmitter)	± 0.1% of reading for 24 months
Flow Pipe near Test Separator	Gas to Atmosphere Press/Temp /Flow	Differential Pressure Flow	Rosemount 3051S2CD2A2A11A1AE5Q4 Tag No. 02-FIT-009	± 0.03% of span	0-100 inches water column	± 0.15% of reading for 24 months
		Absolute Pressure	Rosemount 3051S2CA2A2A11A1AE5Q4 Tag No. 02-PIT-009	± 0.03% of span	0-3,000 psi	± 0.15% of reading for 24 months
		Thermocouple	Rosemount 0068N21C30A060W44E5XA Tag No. 01-TE-009 Rosemount 3144PD1A1E5M5Q4XA Tag No. 02-TIT-009	± 0.02% of span	0-120°F (transmitter)	± 0.1% of reading for 24 months
I/W Well Manifold near Wellhead	Hydrocarbon Analyzer 1	Flame Ionization Detector (FID) on slip stream	Baseline Modcon Series 9000 THA Tag No. DAS-AIT-010A	± 1% full scale	1-20,000 ppm	± 1% for 24 hours
	Hydrocarbon Analyzer 2	IR Detector on slip stream	Hitech Inst. IR600 series Tag No. DAS-AIT-010B	±2.5%	0-100% Methane	±2 %
	Oxygen Sensor	Zirconia sensor	Sensotec Rapidox 2100ZF Tag No. DAS-AIT-011A, 011B	± 1%	<1 ppm to 100% O_2 10E-4 Torr to 40 Bar 5 to 35°C	± 2% per month
	Fire and Flame Sensor	IR/UV Sensor	Honeywell FS20X	NA	-40 to +185°F	--
Water Tank	Analog Level Transmitter	Piezoresistive pressure sensor	Magtech LT-1	½ to ¼ inch resolution	-400 to 400" H_2O Maximum operating pressure 4,500 psi	

All instruments, except for the Piacentine 1-27 and Citizen Green wellhead instruments, were hard-wired to the TSF programmable logic controller (PLC) located in the plant portable control room. The Piacentine 1-27 wellhead instruments were configured to communicate wirelessly with the PLC. The Citizen Green data was recorded onsite and downloaded manually twice each week. The PLC communicated with the BES operator console and acted as the control system for the TSF balance-of-plant equipment.

To be able to analyze all the data taken during the test, the TSF was provided with a data acquisition system (DAS). The DAS for the TSF was engineered, supplied, installed and monitored by the PG&E Applied Technology Solutions (ATS) group. ATS's responsibility included calibrating the test instruments, wiring between the TSF PLC, configuring the wireless transmitters/receivers for the Piacentine 1-27 well and the HP Datalogger, and programming the datalogger that was used to control the gathering and storing of the test data. All required data points were collected and stored every five seconds for the duration of the TSF operation and testing.

Additionally the DAS consisted of a Labview-based monitoring system with data storage backup for compilation and storage of the required test data. The raw data and daily spreadsheet presentation of the information were available to project participants both on site and through a remote Dropbox interface.

6.15.2 TSF Operations

Following construction and commissioning of the TSF, the facility initiated fulltime operations, which were scheduled and directed by the test plan. Operations involved modes: injection and withdrawal (described below). The site was manned 24 hours per day, seven days per week by two independent, but very interactive operations teams.

BES had responsibility for managing all activities at the TSF. They were responsible for the security of the site, controlling site access for all project suppliers, and, most importantly, for the safe operations of the balance-of-plant equipment to follow the test plan as directed by PG&E. The BES operations team included two operators per shift, with two shifts per day, and a four-person team for project management, predominantly on dayshift, but on site when needed.

Because BES operators had continuous feedback from the process stream with respect to flowrate, pressure, temperature, and critical constituents (percentage of oxygen during injection of oxygen-depleted air and percentage of methane during withdrawal), they were constantly interfacing with the Generon operators to ensure the correct process parameters were being met.

Generon had responsibility for operating the ANIP equipment in the mode and at the design point dictated by the test plan and as directed by BES. The Generon operations team included four operators / technicians per shift, with two shifts per day. Generon’s equipment had no remote indication capabilities and relied on the operators constantly performing site-monitoring of their equipment.

The PG&E site manager conducted a daily operations call at 0800 every day the plant was in operation. The call included the PG&E Project Manager, lead subsurface personnel, and BES and Generon site leads. The call focused on any safety or environmental issues from the previous day’s operation, as well as a discussion on the test plan results from the previous day and the plan for the current day.

This daily operations call relied on the information collected by the DAS to track actual versus planned progress during each test plan phase and step.

Injection Mode

To inject into the reservoir, the BOP operators selected the injection mode on the plant control system. The ANIP operators would start the required number of low-pressure (LP) and high-pressure (HP) compressors and nitrogen-processing units (NPUs) to meet the desired step in the test plan. The flow from the ANIP equipment was measured by FE-004 (as indicated on Figure 6-28) to provide the feedback for verification and recording the data for the current test step.

When the ANIP equipment was started, the discharge from the equipment was initially routed to the vent silencer, discharging to the atmosphere. This step can be seen on Figures 6-28 and 6-29. The flow from the ANIP equipment enters Figure 6-28 at the reference "Injection Gas from ANIP." It then exits Figure 6-28 after exiting PCV-003A&B at the reference point "Gas Well to the Test Separator." This flow then enters Figure 6-29 at the reference point "Gas Well to the Test Separator," flows through the Test Separator and the flow control valve, and exits the Vent Silencer.

The ANIP equipment vented the compressed oxygen-depleted air through the vent silencer until a minimum quality of 95% nitrogen was obtained from the NPUs. The minimum required nitrogen quality was required to be recorded on both N_2 analyzers before proceeding with injection. The ability of the NPUs to produce the required nitrogen quality at the required test plan flowrates was the predominant factor in plant start-up time.

Once the appropriate nitrogen quality was obtained, BOP operators utilized PCV-003A & B (as indicated on Figure 6-28) to match the discharge pressure of the ANIP compressors and the I/W well. Once the two pressures were within the required setpoint, FBV-001 (see Figure 6-28) was opened; PCV-003A & B were closed, and injection was initiated.

During the ambient air injection phase, the NPUs were removed from the ANIP equipment string. The start-up process was the same as indicated above with the exception of having to get 95% quality nitrogen to allow injection. The only requirement for injection was to pressure match the ANIP compressor discharge pressure with the current I/W well pressure. Start-ups in the mode were typically less than 30 minutes.

Withdrawal Mode

During the withdrawal test phase the focus was on the percentage methane that was being withdrawn from the I/W well; the maximum methane allowed during withdrawal was 2% in order to stay below pre-test established threshold of 50% of the lower explosive limit (LEL).

During the injection phase, both analyzers were required to have 95% nitrogen before injection was allowed. During the withdrawal phase, if a limit of 2% methane was reached on *either* of the two hydrocarbon / methane analyzers, the withdrawal process was stopped.

To initiate withdrawal from the I/W well, the BOP operators placed the plant in withdrawal mode. FCV-009 (Figure 6-29) was set to the desired test plan flowrate. PCV-003A & B were set to maintain a pressure of 200 psig in the test separator. FBV-001 was opened to initiate the withdrawal flow to the test separator (to remove and liquids from the I/W well discharge) and the vent silencer for discharge to the atmosphere. FE-009 (Figure 6-29) was used to complete the withdrawal flow for test plan adherence.

The test separator collected liquids from the withdrawal flowrate. The tank worked in a batch process and LCV-008 (Figure 6-29) would dump the collected fluids to on-site Frac tanks when LIT-008 (Figure 6-29) indicated the level was at 90%. During the withdrawal phases, no well fluids were produced at flows below 20 MMscfd.

During the withdrawal process, the plant also implemented an exclusionary zone that covered the entire east end of the plant. This precaution was necessary due to the large volume of nitrogen being discharged and the realization areas of low O_2 were in proximity to the vent silencer. All personnel entering the exclusionary zone were required to have a personal O_2 monitor; a buddy system was also implemented to ensure that no one entered the exclusionary zone alone.

6.16 AIT RESULTS

This section summarizes the results of the Air Injection Test (AIT). A more complete report and analysis entitled the "Final Technical Memorandum for Compressed Air Energy Storage, Reservoir Characterization and Full Field Development Model (FTM)" is included in Appendix 6A, Attachment 1.

The injection testing plan was divided into five distinct phases based on the type of operation scheduled as detailed in Section 6.8.4 above.

- Phase 1 – Oxygen-depleted air bubble build
- Phase 1a – Oxygen-depleted air equilibration period
- Phase 2 – Oxygen-depleted air withdrawal/injection cycle testing
- Phase 3 – Data evaluation and post-test equilibration (reservoir is shut-in)
- Phase 4 – Ambient air testing (optional based on results of Phase 3 evaluation)

6.16.1 Phase 1 – Oxygen-Depleted Air Bubble Build

The test bubble for the compression testing program was built with oxygen-depleted air consisting of approximately 5% oxygen and 95% nitrogen. As discussed in Section 7.10, oxygen-depleted air was chosen for the test bubble because the King Island Gas Field still contains native natural gas that is potentially combustible with ambient air for methane concentrations in excess of the lower explosive limit (LEL). The LEL is defined as the lowest concentration (percentage) of a gas in air capable of producing a flash of fire in the presence of an ignition source (arc, flame, heat). At a concentration in air lower than the LEL, gas mixtures are "too lean" to burn. The reservoir simulation model used in the preliminary compression testing program design predicted that the proposed compression testing program should not produce methane in sufficient concentrations to exceed the LEL. Nevertheless, since this field test is the first known test of CAES in a natural gas reservoir, for safety measures, the injected air was chosen to be depleted of oxygen to concentrations below the LEL for the primary 500 MMscf bubble.

Test Bubble Development

Oxygen-depleted air injection was initiated in the I/W well at 1:30 pm on February 14, 2015. For the first 10 days, the injection rate was low due to startup issues and staging with the high-pressure compression. For the next 30 days, the injection rate reached an average of 6 MMcfd. After the installation of additional equipment and fine-tuning the existing compression, the injection rate increased to between 9.0 and 9.5 MMcfd for the remainder of the bubble build. The designed bubble size was 500 MMscf. The final bubble size of 493.1 MMscf was achieved on May 4, 2015 after 80 days of injection.

Reservoir Pressure Response

The reservoir pressures in the I/W well and the two pressure observation wells, Piacentine 1-27 and Citizen Green RD1, increased as a result of the air injection and bubble build. The Piacentine 1-27 and Citizen Green RD1 wellbores at the MRF reservoir level are located 171 feet and 1,980 feet, respectively, from the I/W wellbore at the MRF reservoir level. Figure 6-30 shows a plot of the measured and estimated bottomhole pressures in these wells as a function of the cumulative net oxygen-depleted air injection.

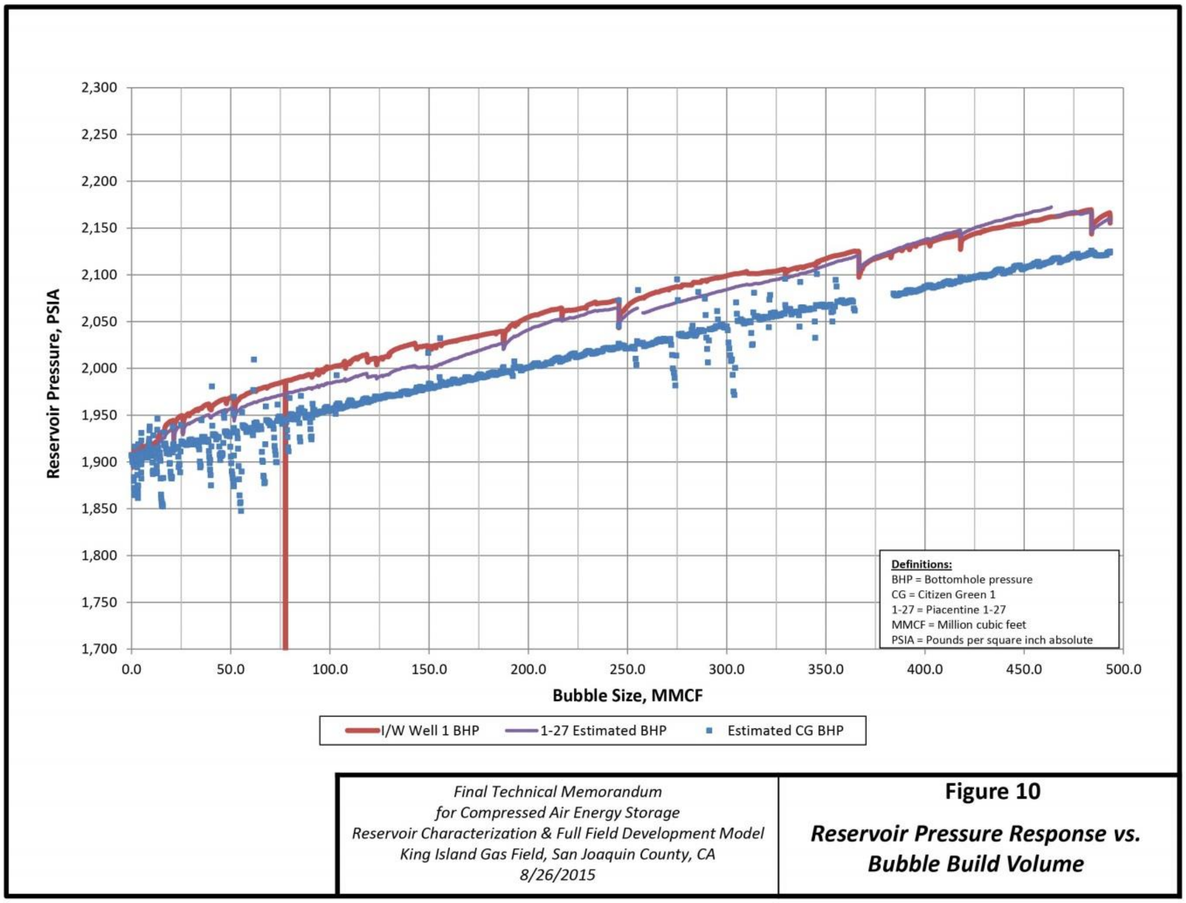


Figure 6-30 Estimated vs. Measured Bottomhole Pressures

The observed increase in reservoir pressure was in agreement with the pre-testing simulation model predictions. The bottomhole pressure in the I/W well was recorded by a surface readout gauge located in a side pocket at 4,610 feet MD (4,565 feet TVD). The bottomhole pressures in the observation wells were determined based on the recorded tubing pressures and an estimated gas gradient from surface to bottomhole in the wellbore.

Pressure Fall-off Testing

During the Phase 1 bubble build period, a series of pressure fall-off tests (FOT) were conducted to investigate the expanding bubble size and average reservoir permeability in the bubble area. Three falloff tests were conducted at the beginning, middle, and end of the bubble build. Pressure data were recorded by a bottomhole electronic gauge with surface readout capability. The gauge was located inside the tubing at 4,610 feet MD (4,565 feet TVD). The results are summarized in the Table 6-8.

Table 6-8 Results of Fall-off Tests in Injection / Withdrawal Well

Fall-off Test Results						
Falloff Test Date Description	**Final Rate**	**Fluid Injectate**	**Estimated Effective Permeability (md)**	**Estimated Bubble Height (Feet)**	**Flow Capacity (kh, md-ft)**	**Skin Factor**
10-28-2014 Step Rate Test	-15,840 bbl/day	KCL Water	140.0	31	4,340	+0.62
2-17-2015 Initial Bubble Build	-2.10 mmscfd	Oxygen-Depleted Air	90.5	60	5,431	-1.45
4-1-2015 Mid Bubble Build	-8.52 mmscfd	Oxygen-Depleted Air	238.1	80	19,050	-1.41
5-1-2015 Post Bubble Build	-9.57 mmscfd	Oxygen-Depleted Air	253.0	80	20,237	-1.40

Definitions
bbl = barrel.
ft = feet.
kh = permeability-thickness.
md = milli-darcy.
mmscfd = million standard cubic feet per day.

The log-log diagnostic plots for all three FOTs exhibit a unique pressure derivative behavior (after the infinite acting radial period), which is interpreted to be characteristic of a radial discontinuity. A radial discontinuity is a change in permeability-thickness, viscosity, and/or porosity-compressibility that occurs at a given radius from a well.

Radial discontinuities are almost always associated with fluid injection. In this case, the injected “air” bubble was distributed radially around the I/W wellbore, and the air/water interface appears as a radial discontinuity. The “air” zone exhibits a relative permeability to gas, gas viscosity, and gas compressibility. The water zone has a relative permeability to water (considering trapped gas), water viscosity, and water compressibility. The relative permeability to gas may not equal the relative permeability to water; however, both viscosity and compressibility are significantly different for air versus water. The result is a change in diffusivity and transmissibility between the two zones, which is seen in the current FOT pressure transient behavior.

The distance to the radial discontinuity or the extent of the “air” bubble was calculated for a simulated test history match using Welltest software. The results of the simulated tests are summarized in Table 6-9, as well as in the FTM and discussed in the FOT reports, which are provided in Appendix P to the FTM. The results show an increasing bubble size consistent with the amount of oxygen-depleted air injection.

Table 6-9 Results of Simulated Fall-off Tests in Injection / withdrawal Well

	Cumulative Net Injection	Static Reservoir Presssure	Bubble Radius	
Date	MMCF	PSIA	FOT, ft	Volumetric, ft
14-Feb-2015	0.0	1,893	0.0	0.0
17-Feb-2015	5.0	1,895	72.3	34.4
25-Mar-2015	187.3	2,009	172.2	176.5
1-Apr-2015	245.7	2,031	214.6	201.8
1-May-2015	484.0	2,125	307.0	276.1

Definitions
FOT = fall-off test.
ft = feet.
MMCF = million cubic feet.
PSIA = pounds per square inch absolute.

Thermal Multi-gate Decay Lithology (TMDL) Logging Results

Halliburton performed Thermal Multi-gate Decay Lithology (TMDL) logging in the Piacentine 1-27 and 2-27 observation wells to obtain information on water saturation (Sw) changes in the injection zone before, during, and after the building of the depleted air bubble.

The purpose of the TMDL logging was to detect depleted air bubble breakthrough at one or both observation well locations by monitoring changes in Sw in the MRF injection zone. The expectation was that depleted air entering a water-saturated permeable layer in the injection zone would result in a decrease in Sw that could be detected with the TMDL log. The runs 1 and 2 Sigma and Sigma-Sw curves tracked each other closely in both wells, suggesting that the depleted air bubble had not reached either well by April 4, 2015.

Due to the inability to run the logging tools deep enough into the Piacentine 1-27 well and the apparent ineffectiveness of the TMDL tool as a result, the third and last run of the TMDL on May 9, 2015 at the end of bubble building (following the first cycle test) was performed only in the Piacentine 2-27. Tracks 4 and 5 of the processed log provide an overlay of the Sigma and Sigma-Sw curves from runs 1, 2, and 3. The curves generally track one another, with the notable exception of the upper 10 feet of the lower MR-1 sand (4750-4760 feet), where the run 3 Sigma-Sw curve shows significantly lower water saturation, which is consistent with displacement of formation water by injected depleted air. This result is consistent with an Eclipse model simulation that showed reduced water saturation at this time in the two model layers that correspond to the upper 10 feet of the lower MR-1 sand.

6.16.2 Phase 1a – Oxygen-Depleted Air Equilibration Period

After the oxygen-depleted air bubble had been built, the reservoir was shut-in to allow time for the pressure to stabilize. A pressure fall-off test was conducted during this period while monitoring bottomhole pressures. The results of that test are included with the discussion of the other FOT tests provided in Section 6.16.1.

6.16.3 Phase 2 – Oxygen-Depleted Air Withdrawal/Injection Cycle Testing

After the bubble was built with the oxygen-depleted air, two sequences of short-term air cycle testing were conducted for the I/W well. The tests aimed to evaluate the King Island reservoir's productivity, injectivity, storage capability, oxygen depletion, and any chemical reactions during the storage and cycling. The cycle testing schedule was designed to evaluate the reservoir performance under normal well cycling conditions, typical of a commercial CAES plant operation. The short-term test program involved monitoring the oxygen-depleted air flow rates and pressures, obtaining samples, and varying operational procedures over a two-week period. Methane and oxygen concentrations of the gas stream were monitored closely during all periods of withdrawal to ensure safety of the surface operations.

Deliverability Testing

Isochronal well performance tests were conducted on the I/W well during the air cycle testing phase. The I/W well was flowed at a constant rate for a one-hour period, then shut-in for one hour to allow the reservoir pressure to return to stabilized conditions. The well was then flowed at a higher rate for another one-hour period. The procedure was repeated to obtain up to four flow periods of equal duration with four shut-in periods of one hour. (This procedure is often referred to as a modified isochronal test procedure because the shut-in period duration is equivalent to the flow period duration.)

The bottomhole and surface wellhead pressures were evaluated to determine the deliverability of the reservoir and well at various producing pressures, including the Absolute Open Flow (AOF) potential of the well, which is defined as the rate at which the well will produce against a zero sandface back pressure. The AOF cannot be measured directly due to physical limitations, but may be extrapolated from the isochronal tests. The wellhead and sandface AOF test results are valuable in setting maximum producing rates, forecasting production, designing surface facilities, and determining reservoir problems (such as rate-dependent skin factors).

A summary and complete analysis of the isochronal well test results during depleted air cycle testing are presented in the FTM. The analysis indicates that the AOF potential of the I/W well is high at the sandface, with an AOF of 590 MMscfd. The wellhead AOF, which is affected by the tubulars and friction, is 83 MMscfd. The I/W well showed that the reservoir is capable of excellent deliverability, on the order of magnitude required for a full field CAES development project. The results are useful to support the planned full field flow potential.

Bubble Performance

The oxygen-depleted air cycle testing program is summarized in Table 6-10. The first cycle testing sequence involved a 24-hour schedule, with a 10-hour withdrawal period followed by a 14-hour re-injection period. This schedule was repeated for three consecutive 24-hour cycles. The second cycle testing sequence investigated a higher rate over a shorter 5-hour withdrawal period followed by a 19-hour re-injection period. This sequence was also repeated for three consecutive 24-hour cycles. These time periods and rates approach those anticipated for normal air-cycling operations.

Table 6-10 Oxygen-Depleted Air Cycle Testing Program

PHASE 2 - Oxygen-Depleted Air Cycling										
Test Day	Day	Date	Withdrawal Period HRS	Withdrawal Rate MSCFD	Withdrawal Volume MSCF	Injection Period HRS	Injection Rate MSCFD	Injected Volume MSCF	Bubble Size MSCF	Comments
81	Tues	5/5/2015	4.0	Various	2815	5.0	9.3	1934	492,191	Isochronal Test 1
82	Wed	5/6/2015	10.0	20.9	8,710	13.5	9.6	5,419	488,900	Cycle Program 1
83	Thu	5/7/2015	10.0	22.3	9,288	13.5	9.1	5,101	484,713	
84	Fri	5/8/2015	10.0	21.4	8,914	12.0	9.5	4,757	480,556	
85	Sat	5/9/2015	0.0	0.0	0	8.0	9.6	3,199	483,755	Shut-in at 8:00 for evaluation
86	Sun	5/10/2015	0.0	0.0	0	0.0	0.0	0	483,755	
87	Mon	5/11/2015	0.0	0.0	0	6.0	8.1	2,023	485,778	Start injection at 18:00
88	Tue	5/12/2015	4.0	Various	2,778	14.0	9.4	5,476	488,476	Isochronal Test 2
89	Wed	5/13/2015	5.0	27.9	5,821	17.0	8.6	6,083	488,738	Cycle Program 2
90	Thu	5/14/2015	5.0	40.4	8,421	17.0	9.5	6,742	487,059	
91	Fri	5/15/2015	5.0	43.9	9,144	11.5	9.5	4,536	482,451	Shut-in at 17:00
END OXYGEN-DEPLETED AIR CYCLING - PROCEED TO EVALUATION PHASE 3										

Definitions
HRS = hours.
MSCF = thousand cubic feet.
MSCFD = thousand cubic feet per day.

Pressures, air-flow rates, water rates, oxygen levels, and hydrocarbon concentration measurements were monitored closely during the cycle testing. A summary of these data are presented in the FTM, and the hour-by-hour DAS data are provided in **Appendix O** of the FTM. Results from the testing are used to history-match the numerical reservoir simulation model and to predict performance under ambient air conditions.

6.16.4 Phase 3 – Data Evaluation and Post-Test Equilibration

After completion of the compression testing program phases with oxygen-depleted air, the PG&E Testing Operations Review Committee (TORC) analyzed all collected data, including withdrawal air and water rates and measured methane concentrations to determine whether to proceed to the ambient air testing phase. The primary focus of this review was to ensure that additional testing with ambient air could be conducted safely.

Preliminary predictions of hydrocarbon gas production for an ambient air testing program were made using the initial King Island simulation model built in June 2013. The data from the simulation model, as well as the field data from the injection / withdrawal testing using oxygen-depleted air, were used to evaluate if such testing could be conducted safely using ambient air where the presence of a sufficient oxygen concentration in the withdrawal air mixture could allow combustion if a combustible gas (methane) was present at a concentration in excess of the Lower Explosive Limit (LEL). The methane concentrations measured during the Phase 2 oxygen-depleted air cycling were less than 0.3%.

The simulation model predicted the methane concentration (in mole %) during the proposed ambient air withdrawal period would initially be zero and increase gradually as a function of the cumulative withdrawal air from the well (Figure 14 in the FTM).

Based on a thorough evaluation by the TORC and key PG&E technical staff, and utilizing the decision matrix discussed in Section 6.11, the decision was made to inject approximately 80 MMscf of ambient air and perform withdrawal testing. This decision included the condition that, during the withdrawal phase, the I/W well would be shut-in immediately and the testing terminated for hydrocarbon or methane concentrations at or above 2% in the withdrawal stream, as indicated by either hydrocarbon analyzer.

6.16.5 Phase 4 – Ambient Air Testing

Injection operations of ambient air commenced on May 21, 2015 and concluded on May 30 after a total of 78.1 MMscf of ambient air had been injected. A single withdrawal period was designed with the intent of producing all of the injected ambient air bubble, plus beginning to draw down the remaining oxygen-depleted air bubble as long as the methane concentration in the produced gas mixture stayed below the threshold 2% level.

Deliverability Testing

Isochronal well performance tests were conducted for the I/W well after the ambient air bubble was injected. The isochronal testing procedure followed the same one-hour flow and shut-in periods used for the previous isochronal tests during the Phase 2 oxygen-depleted air cycle testing. The four step rates were 5, 10, 20, and 30 MMcfd each. Isochronal testing was conducted on May 30 and June 3. The isochronal test on June 3 was necessary because the pressure data being reported by the bottomhole Spartek gauge were suspected of being erroneous. A wireline pressure-temperature gauge (McAnally) was run in the I/W well and hung just above the Spartek gauge. The readings from the wireline gauge showed that the Spartek gauge ceased to accurately measure downhole pressures on or about May 22, 2015. Analysis of the downhole pressure data indicates that, prior to this date, the Spartek readings were consistent with expected behavior and appear to be accurate. Spartek pressure readings recorded by the DAS were disregarded. Downhole pressures were subsequently obtained by conducting monthly bottomhole pressure tests.

The ambient air isochronal well test results are presented, along with the depleted air cycle isochronal test results, in Figures 15 and 16 of the FTM for the wellhead and bottomhole pressure data. The complete analyses are given in Appendix Q of the FTM.

The ambient air data are displayed with the oxygen-depleted air isochronal data. The ambient air isochronal data points fall on the same trendline extrapolations as the oxygen-depleted air data points. The high deliverability of the well is confirmed with ambient air isochronal data.

Withdrawal Testing

An injection sample of the ambient air was collected just prior to the start of injection. The composition of the air injectate is shown in Table 6-11.

Table 6-11 Ambient Air Injectate Composition

Ambient Air Sample - I/W Wellhead		
Collected 5/21/2015 @10:15 am		
Constituent	Mole%	Wt%
Oxygen	22.357%	24.745%
Nitrogen	77.601%	75.192%
Carbon Dioxide	0.042%	0.063%
Total	100.000%	100.000%
Specific Gravity [air=1] real gas	0.9980	
Compressibility, z	0.9996	

Pressures, air-flow rates, water rates, oxygen levels, and hydrocarbon concentration measurements were monitored closely during the withdrawal testing. These data are presented in Appendix O of the FTM on a hour-by-hour basis. Results from the testing are used to compare to the predicted results of the numerical reservoir simulation model.

Table 6-12 is a summary of the chromatographic analyses for the ambient air samples collected during the ambient air testing. The samples were collected at the wellhead and analyzed by Zalco Laboratories in Bakersfield.

Table 6-12 Analytical Results of I/W Well Gas Samples During Ambient Air Testing

CAES - Injection/Withdrawal Well - Withdrawal Gas Sample Analytical Results									
			Detected Results - Mole %						Compression Test Phase
Sample ID	Date	Time	Oxygen	Nitrogen	Carbon Dioxide	Methane	Ethane	Total	
I/W Well Withdrawal Gas Sample	05/31/2015	0:05	22.110	77.575	0.233	0.082	< 0.001	100.00	Ambient Air Withdrawal Test
I/W Well Withdrawal Gas Sample	06/01/2015	17:17	10.785	85.979	2.416	0.818	0.001	100.00	Ambient Air Withdrawal Test
I/W Well Withdrawal Gas Sample	06/03/2015	17:08	3.502	92.502	2.657	1.336	0.002	100.00	Ambient Air Extended Withdrawal
I/W Well Withdrawal Gas Sample	06/04/2015	9:20	2.047	93.773	2.494	1.685	0.002	100.00	Ambient Air Extended Withdrawal

The methane concentration threshold (2.0 mole percent) was exceeded after 80.2 MMscf of cumulative withdrawal from the I/W well. The methane behavior during withdrawal largely tracked the predicted methane concentrations from the simulation results, lending credibility to the model and emphasizing the need to manage and suppress methane production for future CAES operations on a field-wide scale.

6.17 CONCLUSIONS FROM AIT DATA ANALYSIS

The Eclipse computer reservoir model was updated based on the results of the AIT, and additional simulations were run to predict performance during a full-field CAES operation. The base case demonstrates the feasibility of a 300-MW CAES operation in a depleted natural gas reservoir such as the King Island Gas Field. The reservoir pressure and average methane concentration in the produced air during the withdrawal/injection cycling of air are shown in Figure 66 of the FTM for a two-year operating period. The reservoir pressure decreases with time due to formation water continuing to efflux into the aquifer. The percentage of methane is below 2% for the field-wide average rate. The methane concentration decreases gradually with continued CAES cycle operations. Water production is not significant because it is projected to be less than 300 barrels per day total over the two-year operating period. None of the individual wells produce over 4% methane concentration during the two-year period.

Several sensitivity cases were run with the optimized model to investigate what would happen if one or more re-injection cycles were missed or skipped during a week’s operational period (for example, if the plant was unable to operate in an injection mode temporarily). The model results showed that a delicate balance exists to keeping the methane away from the wells during a withdrawal cycle. Re-injection is critical to controlling the methane concentrations by well. Only two or three days may be skipped without field re-injection, before methane concentrations begin to increase to unacceptable levels in some wells. If the lost air injection is made up by over-injection, the model predicts that this action does help the operations to recover and to bring the methane concentrations back down to previous levels.

References

U.S. Bureau of Mines. 1985. *Bulletin 680 – Investigation of Fire, Explosion Accidents in the Chemical, Mining and Fuel-Related Industries – A Manual.*

U.S. Bureau of Mines. 1999. *Bulletin 627 – Flammability Characteristics of Combustible Gases & Vapors.*

Van den Schoor, F. et al. n.d. *The Lower Flammability Limit of Methane in Air at Elevated Pressures and Temperatures: A Theoretical and Numerical Study.*

Zlochower, I.M. and G.M. Green, n.d. *Limiting Oxygen – Impacts on Flammability*.

Appendices

Appendix 6A, Attachment 1, Final Tech Memo for CAES, Reservoir Characterization and Full Field Development Model.pdf.
Appendix 6A, Attachment 2, Flammability characteristics of combustible gases and vapors Bureau of Mines.pdf.
Appendix 6A, Attachment 3, Limiting Oxygen – Impacts on Flammability.pdf.
Appendix 6A, Attachment 4, Methane LFL as function of progress.pdf.
Appendix 6A, Attachment 5, USBM-680 Investigation of Fire & Explosion.pdf.

Chapter 7
CAES Plant and Reservoir Design

7.1 INTRODUCTION

The design of a Compressed Air Energy Storage (CAES) facility must incorporate two primary elements with very different operating constraints: the subsurface storage reservoir and the surface equipment necessary to inject air when power is available for compression, and withdraw air to generate electricity during peak demand periods. The conceptual design needs to consider various operating conditions during both injection and withdrawal.

For this CAES study, the project team modeled and evaluated numerous iterations and sensitivities to derive a design that achieves a match between the operating characteristics of the reservoir and the surface equipment. In considering each aspect of the CAES system, this chapter discusses different optional designs for reservoir development and surface equipment that should be considered in selecting the final full field development design.

As part of the 300-MW CAES feasibility study, and prior to moving forward with a Conceptual Engineering Design for a CAES facility and the reservoir infrastructure, PG&E performed a high-level comparison of two potential CAES technologies that could be used: GTCAES and SMARTCAES™. The analysis sought to determine which technology and its associated configuration would best meet the feasibility study's objectives and provide the operational flexibility needed in an environment of increasing renewable generation. Once a technology was selected, additional analysis was conducted on the reservoir wellfield design, the CAES technology configuration and features and a preliminary cost estimate.

This chapter first reviews the GTCAES and SMARTCAES™ processes. It then considers the SMARTCAES™ system design in terms of wet versus dry cooling and the compression cycle. A project description is included for the King Island CAES Project, with descriptions of the Energy Conversion Facility (ECF) and the storage reservoir. The chapter describes the conceptual engineering developed for the reservoir and the ECF, with details on the air transmission system, the well collection system, and air pipeline. A section discusses how the SMARTCAES design can meet the operational challenges of the grid. The final section discusses the initial capital cost estimates for the major components of the project.

7.2 CAES TECHNOLOGIES EVALUATED: GTCAES vs. SMARTCAES™

This study evaluated two technologies. The first technology (GTCAES) utilizes a conventional gas turbine's exhaust thermal energy to heat the compressed air. It is a modified Brayton cycle similar in configuration to a combined-cycle power plant. In a GTCAES system, a waste heat recuperator (WHR) transfers the gas turbine exhaust heat to the compressed air in a process similar to that of a heat recovery steam generator (without the steam cycle). The heated air is then piped to a turbo-expander generator package (similar to a steam turbine but using air instead of steam) to generate electricity.

The second technology (SMARTCAES™) utilizes two turbo-expanders in series on a single shaft driving an electric generator to generate electricity. In a reheat recuperative configuration, the waste heat from the low-pressure turbo-expander is captured to heat the compressed air prior to the high-pressure combustors, raising the temperature to 1000ºF before entering the HP turbo-expander, which exhausts to the LP combustors, increasing the temperature above 1600ºF and expanding to the recuperator.

In the high-pressure SMARTCAES™ system, which is applicable for this feasibility study, the motive compressed air is pre-heated before entering a third unfired high-high pressure expander that exhausts to the HP combustors. This variation gains additional power from the high reservoir storage pressure.

The CAES facility will utilize high-pressure motive air that is compressed and stored in an underground reservoir that was previously a producing natural gas field. Although the reservoir is considered "depleted" for gas recovery purposes, small levels of residual gas remains in the reservoir and has the potential for mixing with the compressed air and being present in the withdrawal stream that is sent back to the ECF site for power generation.

The technology comparison was performed on the basis of the King Island reservoir being utilized for storage and should not be extrapolated for other storage reservoirs. The following subsections discuss the critical factors considered in the comparison between the two technologies, including plant capacities, performance, costs, and commercial availability.

7.2.1 GTCAES Process

The GTCAES process consists of individual hot air expanders, which are driven by reservoir-stored compressed air heated by the exhaust gases from individual gas turbines via an integrated recuperator. The process, illustrated in Figure 7-1, is based on a natural-gas-fueled gas turbine power generation unit providing both electrical energy and the source of heat for the CAES cycle from the hot exhaust gas of the gas turbine.

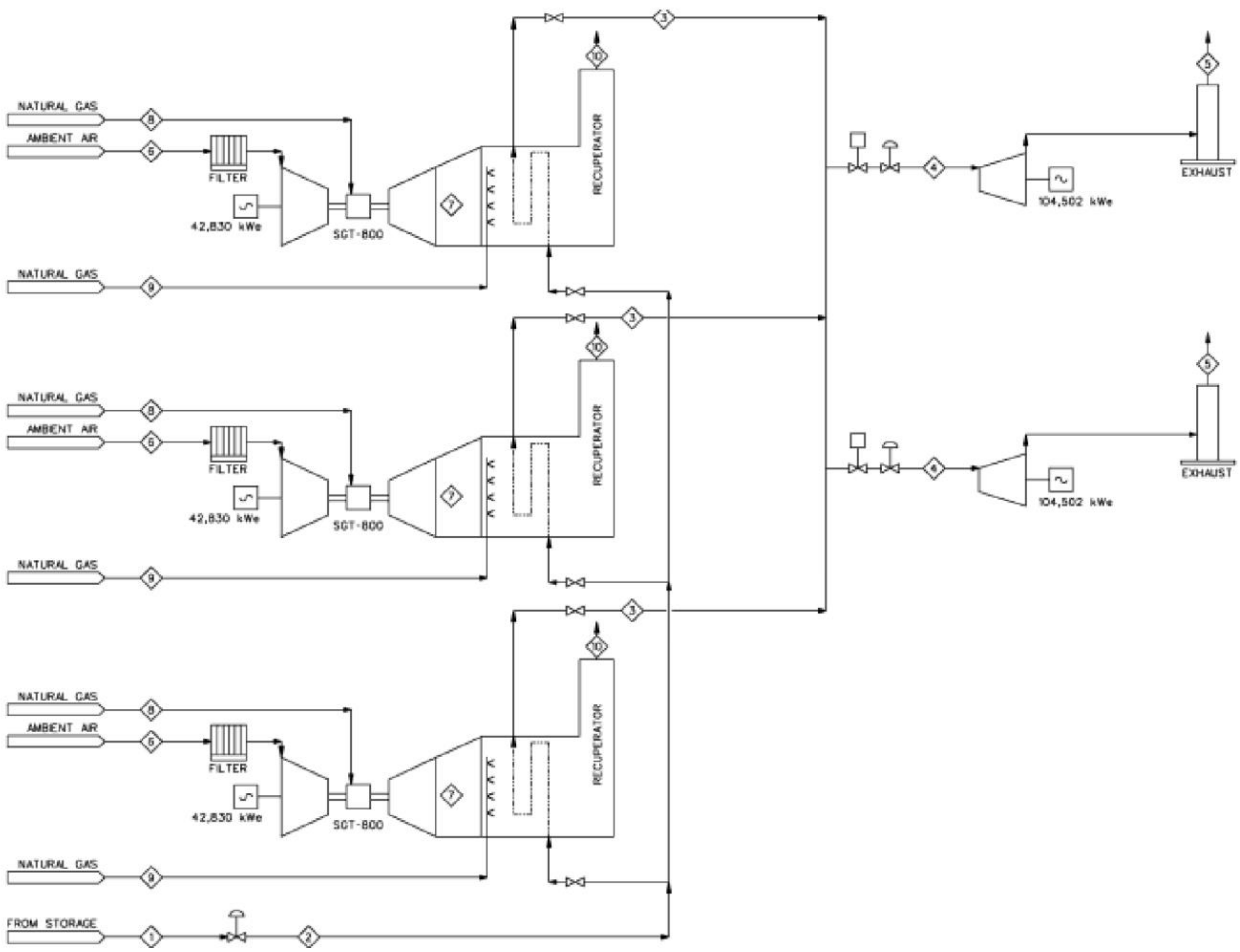


Figure 7-1 GTCAES Process

This exhaust gas typically is in the range of 800-1100°F. The gas turbine operates as in any other typical gas turbine application (i.e., it could operate as a standalone unit subject to the manufacturer's operational limitations on start-up times, minimum load, etc.), but would have a recuperator, located in the gas turbine exhaust path, which heats compressed motive air delivered to the hot air expanders.

Two thermodynamic cycles would be utilized in this design: an open Brayton cycle (gas turbine) and a hot-air expansion cycle (air expanders). This system, designated "GTCAES" for this feasibility study, has been conceptually developed in various forms since 1987 as an advanced CAES technology by others in the energy storage industry.

The GTCAES technology reviewed for this feasibility study does not utilize any air injection options for power augmentation, nor does it utilize adiabatic efficiencies from storing and recovering heat produced during the process. These options are configurations of the technology that have been patented and investigated by Alstom, MHI, TurboPhase, and ESPC (technical papers on the subject are widely available). However, no research and development information was available to verify increased efficiencies, and no operating plants exist with an operating history from which to draw historical data. Also, several engineering challenges associated with utilizing compressed air with residual natural gas content in a gas turbine inlet and/or dry low NOx (DLN) combustion changer have yet to be investigated. One of these challenges includes the expected variable proportion of the potential entrained natural gas/methane in the air and the design of an associated control scheme to manage the entrained gas as an offset to the already planned design fuel burn for the facility. Another challenge is designing the cycle to manage the temperature rise associated with the potential combustion of entrained natural gas, which, if not monitored/controlled, would be incremental to the design/expected fuel burn for the facility.

The intellectual property (IP) rights for several variations of the GTCAES cycle is currently owned by Dresser-Rand. This has the designated term “D-R Gen II CAES” (and has yet to be fully engineered for the configuration discussed herein).

The conceptual GTCAES cycle design that was chosen to provide the required 300 MW for this project would utilize three Siemens SGT-800 Gas Turbines, three waste heat recuperators, and two Siemens SST-800 Steam Turbines modified for compressed air use.

For a GTCAES cycle design, each facility would have its own set of equipment selection criteria used to accomplish its project operational objectives. A decision on the appropriate prime mover and required redundancy would be based on the developer’s business objectives, the reservoir characteristics, and the expected operational profile.

For this feasibility study, it was deemed important to be able to operate even at a reduced output during major overhauls or outages; this criterion led to a decision to incorporate multiple trains of equipment versus only one train. This decision dictated the class of combustion turbine (CT) ratings. The exhaust temperature of the CT then dictates the recuperator and, therefore, the expander performance, further reducing the population of CTs that can be used to meet individual objectives. Commercial availability expectations at the time of procurement (given that the feasibility study and any associated permitting/approvals would take time) need to be considered. The main point here is that for the GTCAES configuration, a number of technical, operational, business, and permitting considerations need to be taken into account when making a final decision on the prime movers.

For the feasibility study, the Siemens equipment was identified for selection from among various gas turbines with power output ranging from approximately 32 MW up to 115 MW. As noted above, this decision dictates other corollary parameters including exhaust temperature, turndown, redundancy, start-up times, etc. Although an economy of scale could be achieved by utilizing a single gas turbine train, the flexibility offered by a multiple train configuration best addresses the objective of developing an operationally, flexible CAES design to assist with the intermittency of high renewable penetrations. For this project and the feasibility study objectives, PG&E determined that, for GTCAES, the Siemen’s equipment/turbines best fit for this configuration in the power outage range mentioned above.

No “used” or custom-designed equipment were considered because one of the objectives of the project was to demonstrate that the CAES system is “market ready.” Market ready was defined as the system is available as a package with integrated controls as an offer through a defined channel and with warranties and guarantees that are financeable. “Used” equipment would necessarily need customized modifications and would not be considered “market ready.”

7.2.2 SMARTCAES™ Process

The second configuration evaluated consists of a modular, single-shaft turbo-expansion system that incorporates an external heat recuperator. This system, called SMARTCAES™, is manufactured by Dresser-Rand (D-R) specifically for compressed air energy storage plants. The process outlining the D-R scope of supply is illustrated in Figure 7-2.

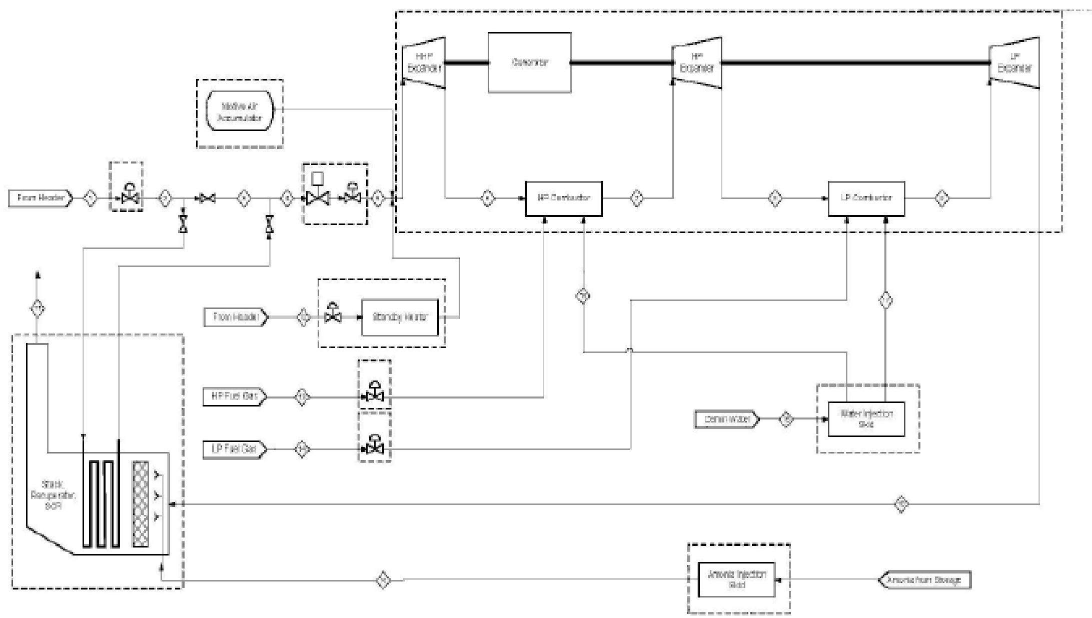


Figure 7-2 SMARTCAES™ Process

Dresser-Rand has similar CAES equipment installed and in utility operation since 1991. For the purposes of this study, Dresser-Rand provided an upgraded SMARTCAES™ train design nominally rated for 150 MW (a 36% increase over their standard offering) that features an HP (high pressure) and LP (low pressure) fired turbo-expander, an unfired HHP (high high pressure) turbine, and an air-preheating recuperator that utilizes LP expander waste heat.

Two trains were proposed to provide at a minimum the 300 MW plant total output being investigated for the feasibility study. A general process flow diagram of the SMARTCAES™ compressor and generation cycle designs are provided in Figures 7-23 and 7-25.

7.2.3 Decision on Technology for Design

While both the SMARTCAES™ and GTCAES systems are theoretically viable, the SMARTCAES™ design had technical and commercial advantages based upon the future needs of the electric system and the expected operations plant profile.

- **Dispatch and Turn-down.** The SMARTCAES™ system has increased dispatch flexibility and lower turn-down ratios than GTCAES, with a more favorable heat rate at minimum load.
    - SMARTCAES™ is guaranteed to reach full load within 10 minutes. Only the gas turbine component of the GTCAES configuration (approximately 50% of the total plant output) is likely to be guaranteed to reach full load within 10 minutes.
    - The turbo-expander for the GTCAES configuration is essentially a modified steam turbine and is expected to be limited to conventional steam turbine startup procedures. Additional modifications or costs to provide hot air to keep the modified steam turbine warm may be needed to generate power within 10 minutes from this part of the cycle in GTCAES.
    - SMARTCAES™ technology is capable of operational turn-down ratios to approximately 10-11% load while meeting emissions guarantees and operating in a stable condition. The GTCAES technology may be limited in turn-down by the emissions compliance requirement of the gas turbine to 50%.
    - The heat rate of the SMARTCAES™ system remains relatively constant at part loads, increasing slightly at minimum load by 7% from the base-load condition. The GTCAES heat rate, however, increases by a factor of approximately 200% at minimum load, resulting in higher fuel consumption per kWh than SMARTCAES™.
- **Warranties.** The SMARTCAES™ power equipment is offered with warranties and performance and emission guarantees on the cycle by Dresser-Rand; this is a significant commercial advantage in terms of reduced risk and ability to finance the project. The GTCAES system is likely to have warranties on individual equipment components, but no supplier has yet offered full performance guarantees on the cycle or process at the time of this investigation.
- **Commercial Development.** The SMARTCAES™ technology has some commercial development such as the McIntosh (Alabama) single-train unit (utilized with a salt dome formation) with historic operational and performance data. The high-pressure SMARTCAES™ offering is an upgraded version with increased motive air flow and pressure, ideally suited for a porous rock formation reservoir/applications.

Other parameters such as capital cost, full-load emissions, permitting hurdles, and performance at full rated loads were found to be similar between the two technologies (though part-load emissions are significantly better with SMARTCAES™). Both technologies provide benefits to grid reliability when dispatched for supporting renewable generation sources.

7.3 SMARTCAES™ SYSTEM DESIGN

Once the decision was made to focus the conceptual engineering effort on the SMARTCAES™ configuration, two additional, critical decisions needed to be made:

1. Should the design incorporate wet or dry cooling?
2. Should the compression cycle be based on a 6- or a 12-hour/day reinjection cycle?

7.3.1 Wet vs. Dry Cooling

The PG&E Compressed Air Energy Storage (CAES) Project objectives include the conceptual design of an Energy Conversion Facility (ECF) that incorporates a compression plant to compress air for storage and a power generation plant to utilize the stored air for generating 300 MW (nominal) of electricity. A pre-requisite to the conceptual design process was the selection of the compressed air and equipment cooling methodology, which affects both the cost and performance of the facility.

Both the compression and the generation plants have equipment that require cooling; however, the compression system, which has a cooling load of approximately 430 MMBtu/hr, requires significantly more cooling than the 20 MMBtu/hr cooling load of the generation plant.

Therefore, PG&E studied the performance and costs of wet and dry cooling methodologies for the compression plant, with the assumption that the generation plant's vendor preferred solution (air-cooled heat exchangers) would be utilized for the smaller heat load. The study also looked at the concept of air re-injection time cycles since the cooling load is dominated by compression time, and the cooling load has a direct impact and associated pros/cons on each method of cooling.

Two cooling options for the air compression plant were investigated:

1. **Dry Cooling** – includes an air-cooled heat exchanger, circulating water pumps, interconnecting piping, and the associated equipment to transfer heat between the compressors and the cooling water system. See Figure 7-3 for a simple block diagram of a dry cooling system.

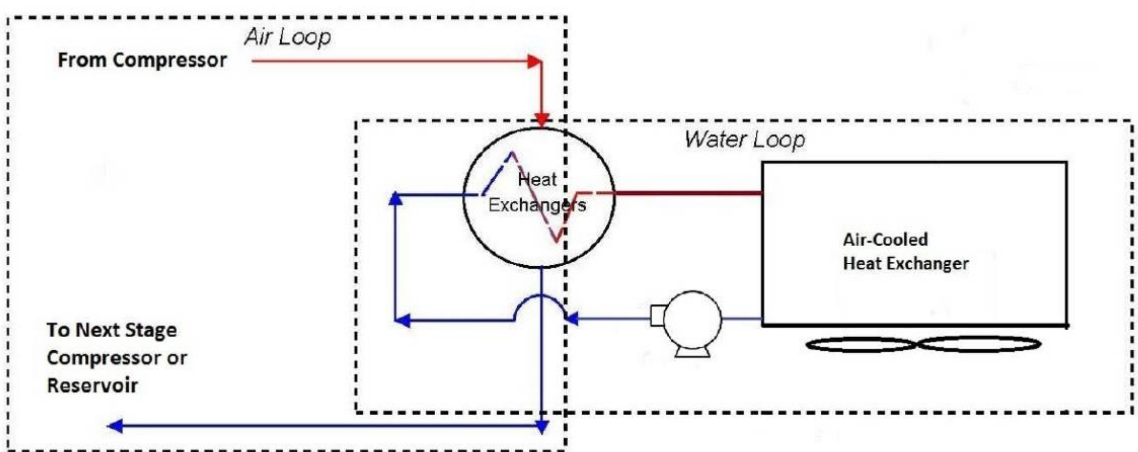


Figure 7-3 Dry Cooling System

2. **Wet Cooling** – includes a mechanical draft cooling tower, circulating water pumps, interconnecting piping, and the associated equipment to transfer heat between the compressors and the cooling water system. See Figure 7-4 for a simple block diagram of a wet cooling system.

Note: An analysis described in the *WorleyParsons Conceptual Design and Cost Estimate Report* (see Appendix 7A, Attachment 5, WP Conceptual Design ECF) was performed with the assumption that the facility would utilize wet cooling, based on siting the ECF at a specific site with access to recycled water. The entire report and contents of this chapter are based on that premise. However, to allow for the possibility that dry cooling could be selected due to site control, permitting, or operational considerations, WorleyParsons was tasked with investigating the high-level changes that would be encountered based on the choice of an alternate ECF location. The results of that analysis, the *WorleyParsons Conceptual Design and Cost Estimate Report, Addendum 1 for Alternate Ming Centre Site*, is Appendix 7A, Attachment 5, WP Conceptual Design ECF. Dry cooling would be required at the alternate site

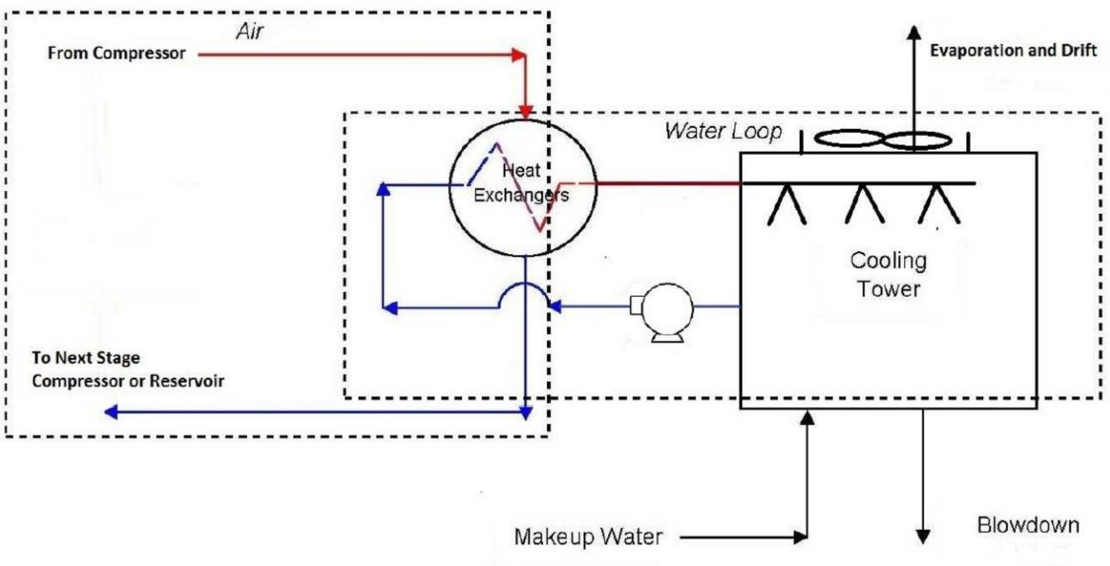


Figure 7-4 Wet Cooling System

7.3.2 Dry Cooling Options

A dry cooling system for the compression plant would have the identical compressor air process and shell-and-tube and aftercoolers as the wet cooling system. However, instead of circulating the water through a cooling tower, the water in the cooling loop would be cooled by an air-cooled heat exchanger (ACHE). Figure 7-5 depicts a preliminary water balance diagram developed during the analysis (other water balances are included in the *WorleyParsons Conceptual Design and Cost Estimate Report, Addendum 1 for Alternate for Ming Centre Site*) (see Appendix 7A, Attachment 5, WP Conceptual Design ECF).

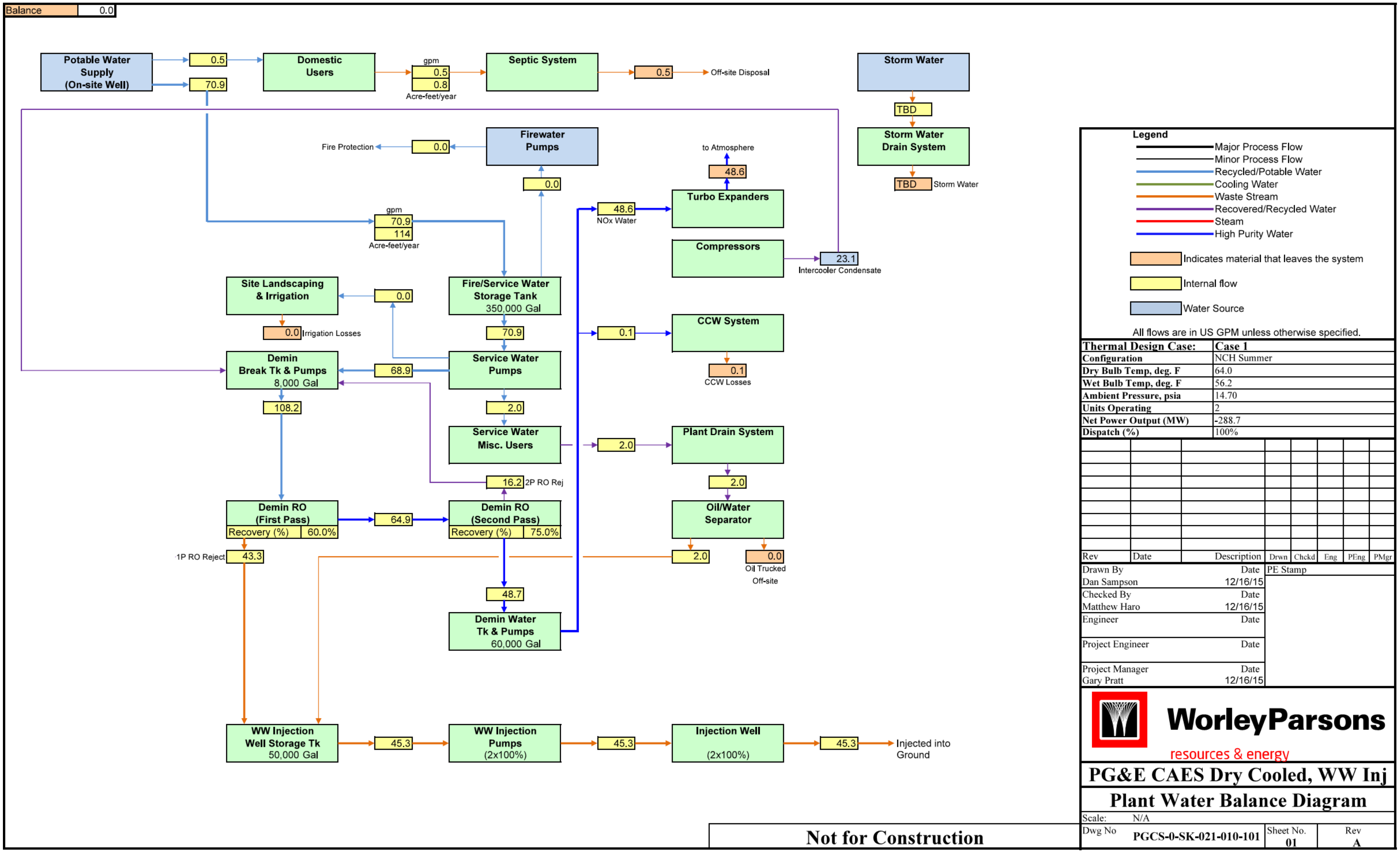


Figure 7-5 Dry Cooling Water Balance

The ACHE would consist of a number of individual ACHE bays installed side-by-side. Each bay of the ACHE would contain bundles of small-diameter finned tubes (typically 1 inch diameter) welded into a header at each tube end. The heated water from the compression system shell-and-tube heat exchangers would be pumped through the tube bundles. Two or three fans mounted directly below each bay of tube bundles would force air up and through the tube fins to cool the water.

The cold water temperature that can be achieved depends on the ambient temperature during operations. Typical ACHEs are designed for an approach of 10°F—that is, the cold water temperature will be 10°F higher than the ambient dry bulb temperature. Therefore, the cooling water temperature to the intercoolers/aftercoolers is heavily influenced by ambient dry bulb temperature (much more so than wet cooling, which is based on the ambient wet bulb temperature). As the ambient air temperature rises, the effectiveness of the air cooling declines and results in warmer cooling water. The varying cooling water temperature, in turn, affects the air temperature entering the next compressor stage. The higher cooling water system temperatures result in less efficient compressor operation, requiring more electrical power to do the same amount of work.

A dry cooling system designed to operate during times of higher temperatures (a distinct possibility as outlined in Section 7.3.1) would require the need for a larger heat transfer surface. Therefore, if additional heat transfer duty is required, additional bays of tube bundles and fans would be added to the ACHE, resulting in expansion of the configuration/footprint and higher capital costs.

7.3.3 Wet Cooling Options

The California Energy Commission (CEC), consistent with the policies adopted by the State Water Resources Control Board and the Warren-Alquist Act, requires that alternative water supply sources (such as recycled water) and alternative cooling technologies (such as air-cooled heat exchangers) be proven “environmentally undesirable” or “economically unsound” before fresh water can be considered as a make-up water source for a cooling tower. For the purposes of the *WorleyParsons Conceptual Design and Cost Estimate Report* (see Appendix 7A, Attachment 5, WP Conceptual Design ECF), it was assumed that recycled water would be used based upon its availability at one of the potential ECF sites.

Just as a source of cooling tower makeup water is one challenge for wet-cooled systems, the challenge of what to do with the cooling tower blowdown wastewater is another. Two possible alternatives—discharge to a local wastewater treatment facility or to evaporation ponds—were not feasible. The return to a local water treatment facility was investigated but found to be unworkable because the required water return quality criteria was comparable to the water quality being provided, and therefore, does not allow for concentration in the tower.

A zero liquid discharge (ZLD) system is feasible; enough space is available to accommodate the ZLD system, along with the other required equipment, within the site boundaries. The ZLD system analysis was driven by a thermal process of brine concentrators and crystallizers with appropriate water storage tanks to allow continuous ZLD operation, despite the cycling operation of the compression plant.

ZLDs have a well-documented history of cost and operational challenges; however, an advantage of the ZLD is that it would recycle most of the blowdown wastewater to the plant for process and cooling tower makeup. The blowdown would be pumped to a brine concentrator, which would concentrate the entrained silica and other minerals, and send approximately 95% of the recovered water (distillate) back into the plant to be used as cooling tower makeup or for other water system needs. The remaining waste from the brine concentrator (concentrate) would form a slurry that would be sent to a crystallizer, where a small amount of the remaining water would be recovered as it reduces the brine concentrate to a nearly dry solid. The solid would be pressed into cake for disposal in an approved landfill. See Figure 7-6 for the water mass balance utilizing a ZLD system.

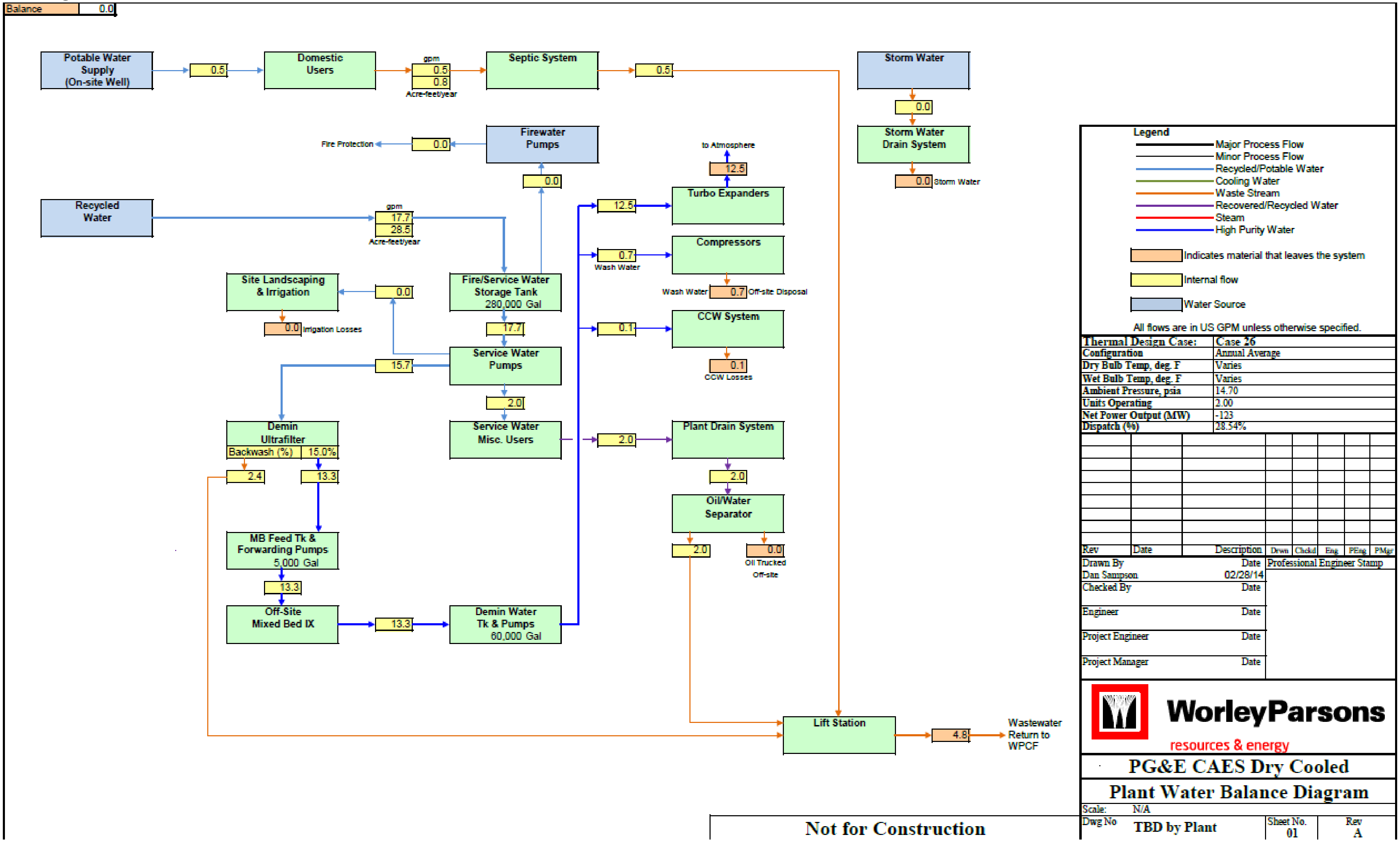


Figure 7-6 Wet Cooling Water Balance (Utilizing ZLD System)

For this feasibility study based on the use of a wet cooling option, the decision was made to utilize deep well injection of the wastewater for the following reasons:

- Lower capital and operating costs
- Improved performance with wet cooling
- Permitting synergies (i.e., the wells would be permitted at the EPA in parallel with the air injection/withdrawal wells)

The annual average water balance case is shown in Figure 7-7. Water balances for other ambient conditions and operations are included in the *WorleyParsons Conceptual Design and Cost Estimate Report* (see Appendix 7A, Attachment 5, WP Conceptual Design ECF).

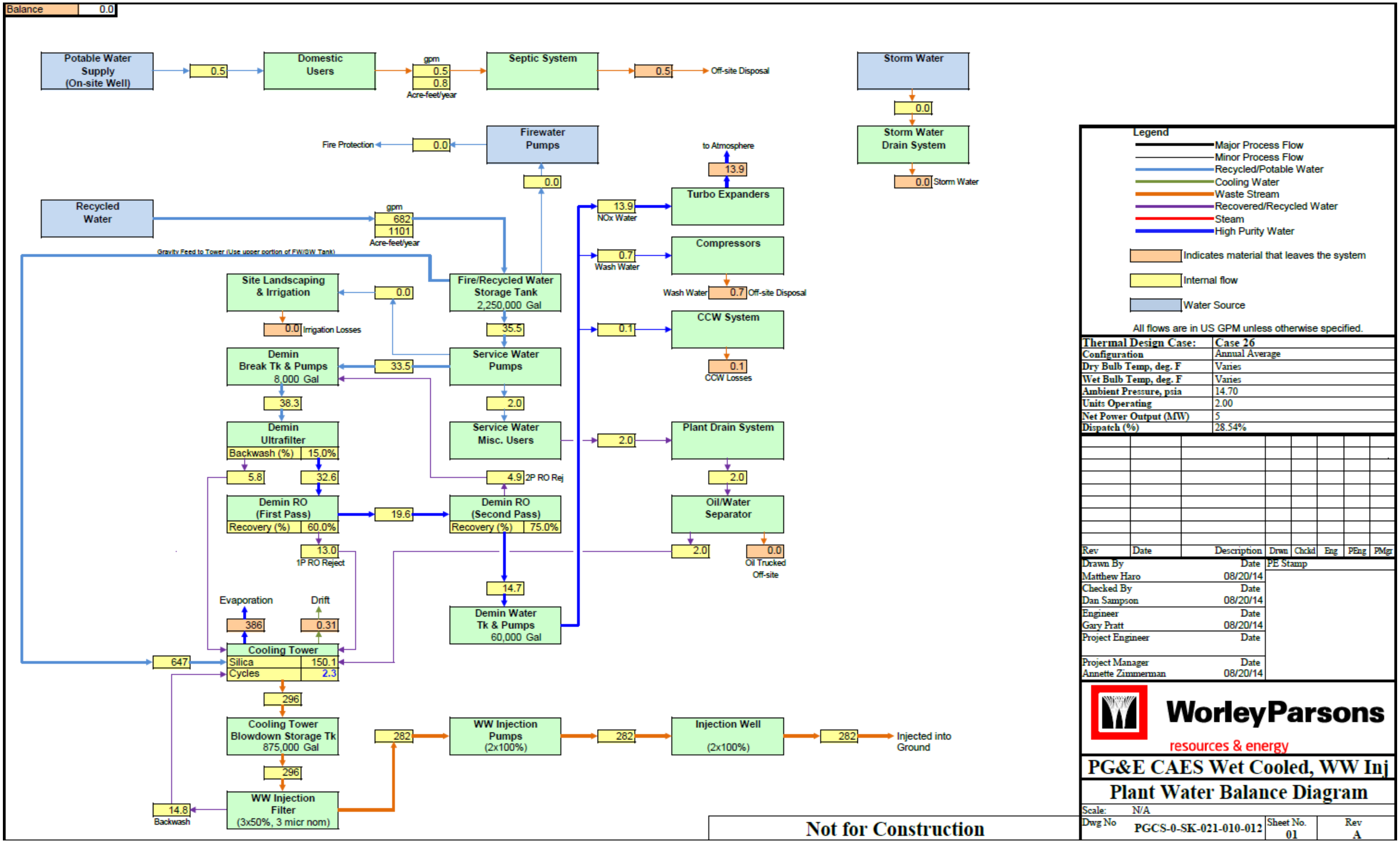


Figure 7-7 Wet Cooling Annual Average Water Balance (Utilizing Deep Well Injection)

The water balance shows the water losses by various processes during plant operations. For average annual ambient conditions at 100% compression, 682 gpm will be required from the WWPCF. Ultimately, the largest loss is from cooling tower evaporation, at 386 gpm. The conceptual water system was designed using the recycled water directly as cooling tower makeup, which limits the cycles of concentration in the cooling tower to about 2.3. This low ratio, therefore, has high rates of makeup water to, and blowdown wastewater from, the cooling tower, but in parallel eliminates the capital and operating cost of incoming water treatment before it is delivered to the cooling tower.

Ultimately, plant cooling can be accomplished by multiple methods (dry or wet cooling and within the wet cooling option, different approaches). The developer of the facility will have opportunities to design the cooling system to match its preferred approach when considering all factors including capital costs, operating costs, reliability, performance, and environmental impacts.

7.3.4 Compression Cycle: 6 vs. 12 Hours

The initial concept for the CAES facility assumed that a CAES facility would generate for 10 hours/day, Monday through Friday every week; it would then run the compression cycle for 12 hours/day, Monday through Friday every week; the Monday through Friday operation would leave a "deficit" in the air bubble, which would then be made up by running the compression cycle on the weekend (Saturday through Sunday). See Table 7-1.

Table 7-1 12-Hour Injection Cycle

King Island Program 300 MW Plant: 12-hour Injection				
Day	Air Rate, MMCFH, Withdrawal; (Injection in parentheses)	Hours	MMCF	Air Cumulative – MMCF
1	45.8	10	458.33	458.33
	0.0	1	0.00	458.33
	(22.9)	12	(275.00)	183.33
	0.0	1	0.0	183.33
2	45.8	10	458.33	641.67
	0.0	1	0.00	641.67
	(22.9)	12	(275.00)	366.67
	0.0	1	0.00	366.67
3	45.8	10	458.33	825.00
	0.0	1	0.00	825.00
	(22.9)	12	(275.00)	550.00
	0.0	1	0.00	550.00
4	45.8	10	458.33	1,008.33
	0.0	1	0.00	1,008.33
	(22.9)	12	(275.00)	733.33
	0.0	1	0.00	733.33
5	45.8	10	458.33	1,191.67
	0.0	1	0.00	1,191.67
	(22.9)	13	(297.92)	893.75

6	(22.9)	24	(550.00)	343.75
7	(22.9)	15	(343.75)	0
	0.0	9	0.00	0

Conditions within the California market are not as "static" as these initial assumptions would indicate. A few examples:

- The above operating profile assumes that the 98 hours during the week needed for compression are all low-priced hours and/or periods of excess generation; one of the key valuation components of a CAES plant is the ability to run the compression equipment to store excess generation and/or to use low-cost power.
- Similarly, the above operating profile also assumes that the need for the generation component of the plant only occurs during the peak/day time and that it occurs over a constant 10 hours, every Monday through Friday.

System conditions, which affect both supply and demand (and thus prices), are not as static as the operating profile assumption would indicate. Two items to consider:

- The California Independent System Operator (CAISO), the entity responsible for managing the majority of California's electric transmission system, often operates plants at their minimum operating point (Pmin); this then allows the CAISO to dispatch these plants up (or down) based on the real-time needs of the grid. With ever increasing amounts of intermittent power connecting to the grid (wind, solar, etc.), this practice will become increasingly important.
- As indicated in Figures 2-2 to 2-4 and Tables 2-1 and 2-2, future conditions indicate that during certain months of the year, an oversupply of generation may occur during the day, specifically during times of the day that would have been considered peak hours. Those hours would be prime candidates for using the excess generation to run the compressors to charge the reservoir.

These are just a couple examples of how system needs and/or conditions can change during the course of the day and into the future. They draw attention to the fact that storage and/or generation resources that have operational flexibility (i.e., fewer restrictions on when and how they operate) will have the most value both to the utility that contracts with those resources and to the system operator (such as the CAISO) that will then utilize those resources.

Before determining certain impacts (cost, operations, etc.) of moving to a 6-hour injection cycle, reservoir modeling was conducted to look at the sensitivity of moving to a higher injection rate. An air injection rate twice of that assumed for the 12-hour was utilized. Table 7-2 shows the weekly operation profile.

Table 7-2 6-Hour Injection Cycle

King Island Program 300 MW Plant: 6-hour Injection				
Day	Air Rate, MMCFH, Withdrawal; (Injection in parentheses)	Hours	MMCF	Air Cumulative – MMCF
1	45.8	10	458.33	458.33
	0.0	4	0.00	458.33
	(45.8)	6	(275.00)	183.33
	0.0	4	0.0	183.33
2	45.8	10	458.33	641.67
	0.0	4	0.00	641.67
	(45.8)	6	(275.00)	366.67
	0.0	4	0.00	366.67
3	45.8	10	458.33	825.00
	0.0	4	0.00	825.00
	(45.8)	6	(275.00)	550.00
	0.0	4	0.00	550.00
4	45.8	10	458.33	1,008.33
	0.0	4	0.00	1,008.33
	(45.8)	6	(275.00)	733.33
	0.0	4	0.00	733.33
5	45.8	10	458.33	1,191.67
	0.0	4	0.00	1,191.67
	(45.8)	10	(458.33)	733.33
6	(45.8)	16	(733.33)	0
	0.0	8	0.00	0
7	0.0	24	0.00	0

As can be seen in Table 7-2, by injecting at higher rates, more available hours are available during the week (including the weekend) during which the reservoir can be charged. This is important for the following reasons:

- Prices are not static. By being able to inject at higher rates, the CAES facility has more flexibility to “pick” the rights hours at which to run the compression.
- System loads are not static. By being available to inject at higher rates, the CAES facility will also be available to operate in generation mode sooner than under the 12-hour scenario and thus be able to capture potentially high value hours.
- By injecting at a higher rate for more than the 6 hours/day as indicated in Table 7-4, the facility may be able to operate in generation mode 7 days/week. This is important in California. Currently units that are available and able to generate for a minimum duration of 4 hours/day, 7 days/week are considered more valuable from a Resource Adequacy product perspective. (Resource Adequacy rules may change.)

The preliminary 6-hour modeling, conducted to determine any fatal flaws, identified one issue. As shown in Figure 7-8, the injection rate degrades during the early cycles, indicating some issues may arise with injecting at this higher rate. The project team viewed this as a short-term issue caused by bumping up against the assumed maximum reservoir pressure of 3,000 psia before the injection volume is completed within 6 hours.

After the reservoir has been cycled a few times, the issue may subside. Additionally, more wells or a different distribution of those wells across the reservoir could solve the issue. These items would be addressed in the final reservoir design.

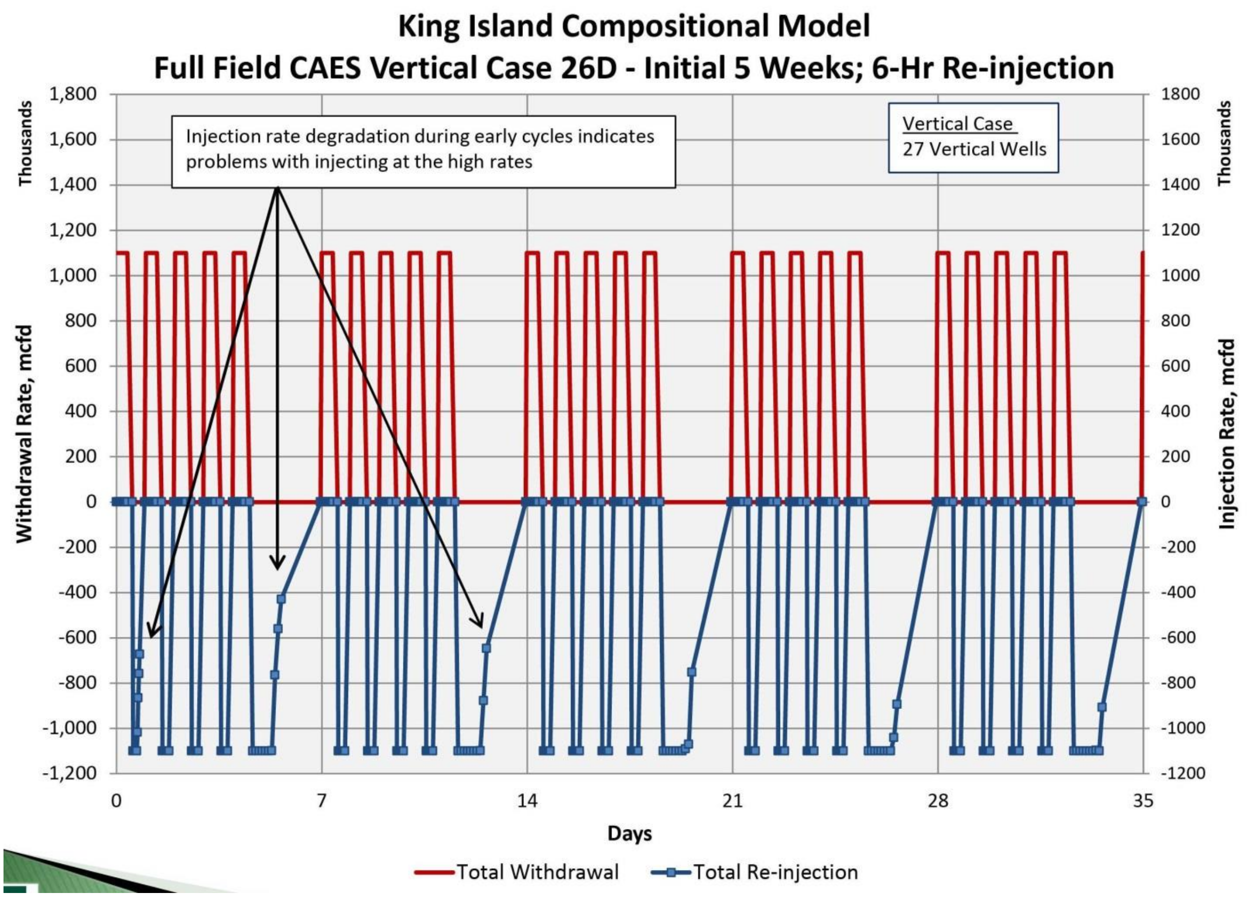


Figure 7-8 Preliminary 6-Hour Reservoir Modeling Results

7.4 PROJECT DESCRIPTION

The conceptual engineering effort, described in Section 7.5, is based on a specific project description for a specific location. This design may be different than the design(s) submitted by independent developers as part of the RFO. The project description for the King Island CAES Project includes the two major project operational locations—the ECF and the storage reservoir—as well as the needed equipment, pipeline, and wells.

7.4.1 Project Description for the King Island CAES Project

The conceptual design for the King Island CAES Project (KICP) would provide the capability to store energy in the King Island gas reservoir in the form of compressed air and to later retrieve the energy for power generation from the ECF rated at a gross nominal general capacity of

316 megawatts (MW). Compressed air would be piped from the ECF location to the King Island field, where it will be stored until it is needed for power generation, at which point it would be returned to the ECF location via the same air pipeline.

The principal elements that the base case project developed as part of the feasibility study, and upon which the *WorleyParsons Conceptual Design and Cost Estimate Report* (see Appendix 7A, Attachment 5, WP Conceptual Design ECF) was generated, include the following design features:

- ECF/power island site of 20 acres for the turbo-machinery, including air compressors, natural gas compression, turbo-expanders, generators, switchyard, and cooling equipment;
- Underground storage injection and withdrawal (I/W) wells and equipment at two well pads, hydrocarbon monitoring/control equipment, control building, and water storage tanks
    - West well pad, 6 acres, 20-25 air I/W wells, 2 water withdrawal wells, up to 1 water injection well
    - East well pad, 4 acres, 5-10 air I/W wells, 2 water withdrawal wells, 1 water injection well
- Underground compressed air pipeline, ECF to east well pad; 2.6 miles
- Air collection pipeline (east well pad to west well pad); 0.3 mile
- Natural gas pipeline to convey fuel to the ECF from a PG&E distribution feeder main; 1.4 miles
- Generator tie-line connecting the ECF to the existing Gold Hill-Eight Mile 230 kV transmission line circuit; 270 feet
- Recycled cooling water supply pipeline; 0.3 mile

7.4.2 Facility Design

The KICP facility would have two major project operational locations: (1) the ECF/Power Island and (2) the storage reservoir and I/W well field with two well pads. An underground compressed air pipeline and water line would connect the ECF with the well pads (see Figure 7-9).

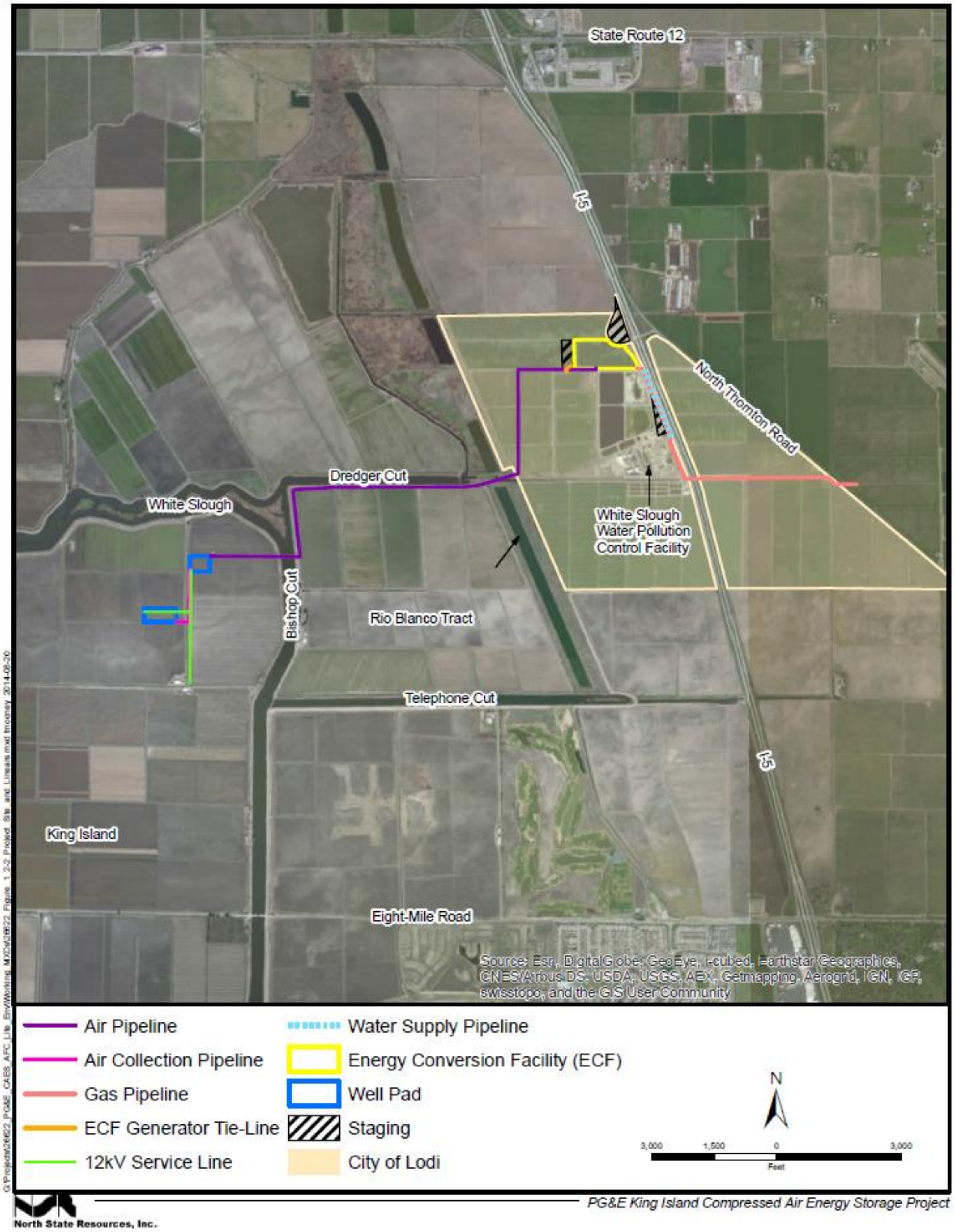


Figure 7-9 Project Site and Linears

As currently envisioned in the conceptual design, the KICP would employ two Dresser-Rand CAES compression trains and two expansion/generation trains. Each compression train would consist of a multistage compressor section driven by a dedicated approximately 137 MW (nominal rating) electric motor. Each compression train would be capable of producing up to 410 pounds per second of air at a compressor outlet pressure of up to 2800 psia.

Each expansion/generation train would be rated at 158.3 MW (gross). Thus, at a maximum compression load, the facility would consume up to 274 MW of electric energy, while at maximum generator output, the facility would consume 1215 MMBtu/hr of energy from natural gas and produce 316 MW on a gross basis (the facility is designed for 300 MW of nominal maximum continuous rating, otherwise known as Net Rated Output, for 10 hours). Facility power production on a net basis accounts for various auxiliary loads of approximately 6 MW. Figures 7-23 and 7-25 are the process flow diagrams of the KICP compression and expansion/generation systems, respectively.

The KICP reservoir is a depleted natural gas well field in the Mokelumne River Formation approximately 4,650 feet below ground surface. Based on project design modeling, the reservoir would likely operate over a wellhead pressure range of approximately 1,900 and 2,830 psia (static pressure range).

Air compression to build and refresh the reservoir bubble of compressed air would occur in four stages. Because air compression raises air temperature, the air would need to be cooled between stages using circulated cooling water to absorb and convey heat away from the compressors. This heated cooling water would be re-cooled in a conventional mechanical draft cooling tower using recycled water as the make-up water.

The process flow diagram in Figure 7-25 depicts the expansion/generation process. When required to meet system needs, the stored compressed air would be released from the reservoir, preheated in a recuperator, and expanded through the reheat-turbo-expander train. At maximum generator output, approximately 400 lbs/second per train of reservoir air would be piped through the recuperator and preheated to 630°F. The recuperator reclaims the low-pressure expander’s exhaust heat and consequently reduces the generation heat rate significantly. A very-high-pressure (VHP or HHP) expander is used as a topping turbine to provide additional power beyond what the LP and HP expanders can provide and to provide a more efficient mechanism for stepping down reservoir pressure to the design inlet pressure of the HP expander.

The KICP would manage any residual entrained native natural gas using a combination of turbo-expander system controls and well field management and operational strategies. The combustor system controls would manage the temperature rise associated with any residual native natural gas. These controls fall into two categories: (1) fuel gas valve adjustment based on measured residual native natural gas in the air pipe, and (2) recuperator bypass if other methods are insufficient to manage the residual native natural gas. In addition, the facility could reduce load, remove a train from service, or remove the I/W well producing high levels of native natural gas from service.

Each of the two expander trains has three bodies of multistage expansion. Compressed air from the reservoir is first preheated in the recuperator from where it flows to the very-high-pressure (VHP or HHP) expander. The discharge of VHP expander is directed to the HP expander, where it is heated via natural gas-fired combustors, which are also equipped with water injection for emissions control. These combustors are mounted on the inlet of the HP expander and provide the first direct heat input for the stored, compressed air, after pre-heating in the recuperator. The gases exit the HP expander, flowing to the low-pressure combustor, where additional natural gas is burned to increase the gas temperature for further expansion in the LP expander.

The low-pressure (LP) expander features eight gas-fuel combustors arranged in a can-annular configuration on the expander. The combustor system includes water injection for NOx abatement. Gases exiting the LP expander flow through the recuperator, where they are used to heat the cool air entering the expansion-generator train from the reservoir, and then exhaust through the stack.

The KICP compression system would consist of three compressor sections, each driven by an electric motor. The low-pressure and intermediate-pressure compressors each incorporates one section of compression, while the high-pressure compressor incorporates two sections of compression in a back-to-back configuration, making four sections of compression. The compressed air is cooled after each section to reduce the temperature of air entering the next section. Water-cooled heat exchangers are used for all process air-cooling requirements.

7.4.3 Process Description – Storage Reservoir and I/W Well Field

The compressed air storage reservoir is an underground geological structure located approximately 4,700 feet below the surface on King Island. The reservoir is a nearly depleted natural gas field that has been used for natural gas production from October 1985 to the present. All gas production from this field would have ceased prior to project commissioning, making the structure available for CAES. The project design includes two well pads, totaling 10 acres, with up to 30 total I/W wells. Each well pad would also have a control building, native natural gas monitoring and a control system to manage residual natural gas entrained in compressed air withdrawn from the I/W wells, and a produced water storage tank. The base case design includes a total of two injection wells for produced and wastewater disposal: one located at the east well pad and one either located at the west well pad or at the ECF. Figures 7-16 and 7-17 are general arrangement drawings of the west and east well pads, respectively.

Compressed air pumped through the air pipeline from the ECF would be injected into the storage reservoir at the well pads. When needed for energy production, air would be released from the reservoir, stripped of produced water, monitored for excess native natural gas, and then returned to the ECF through the pipeline.

Reservoir core analysis and modeling indicate that, with an established air compression bubble of approximately 8 to 10 Bscf (billion standard cubic feet), the reservoir can support a 300-MW power generation facility under a variety of operation scenarios. The development of the reservoir would be similar to that of a natural gas underground storage reservoir. The key elements are high-capacity I/W wells, observation wells to monitor conditions within and around the reservoir, and water injection wells for the disposal of produced and ECF wastewater. The

I/W wells' location within the reservoir needs to be based on a plan to minimize flow interference between the wells during periods of high flow rates and also to fully utilize the reservoir's volumetric capacity, which provides for longer sustained operations.

The anticipated design of the I/W wells is based on the results of the compression modeling and the simulation results of various well completion designs. These results indicated that straight, directional, or highly deviated wells are preferred to horizontal well designs. Directional and highly deviated wells would provide better control over the native gas concentrations in the withdrawal flow stream than horizontal wells.

7.4.4 Water Withdrawal and Disposal

One of the key findings from the modeling work is that reservoir pressure will be affected by a partial water drive. As natural gas was produced from the reservoir, water flowed into the reservoir from the underlying aquifer in response to declining pressure resulting from the release of the natural gas. Over time, reservoir pressure has continued to rise due to a continued influx of water. This response has been relatively slow, and the modeling has revealed that the effort to push the water from the reservoir back into the aquifer would likely be slow as well. With a given maximum injection pressure constraint, a developer could either inject at a rate that water would naturally efflux from the reservoir (push the water back with pressure) or physically remove a volume of water from the invaded zone in the reservoir. Time constraints to develop an adequately sized air bubble in a reasonable period of time may require the physical removal of some water from the reservoir.

The initial modeling runs assumed that the water removal strategy during the bubble-build period would involve four withdrawal wells located on the perimeter of the storage reservoir and operating at approximately 3,200 Bbl per day per water well. Modeling based on this water removal rate and a maximum injection pressure of 3,000 psi showed that building an 8 to 10 Bscf bubble in approximately one year would be feasible. The removed water would be re-injected into EPA-permitted injection wells completed to zones deeper than the underground sources of drinking water (USDW); in the vicinity of King Island, the Starkey formation would meet this criterion. Disposal of produced water into the Starkey formation would require one or more disposal wells, tankage for temporary storage, properly sized pumps for this purpose, and the interconnecting piping between the equipment location and the disposal well site.

In addition to the need to dispose of water withdrawn from the storage reservoir during the bubble build period, the project will also need to dispose of waters produced during normal operations. Reservoir modeling has indicated than an estimated 2,500 to 3,500 Bbl/day of water could be produced separately from the air flow stream during normal withdrawal operations. This produced water would be disposed of in the wastewater injection wells.

7.4.5 Reservoir Operations

Unlike other gas storage operations, the air stored in a CAES reservoir is the motive force that would be used to drive electric generation equipment. The following principles of operation would be followed to maintain the maximum capacity and greatest operational flexibility for the reservoir:

- The bubble build will take place slowly and will ensure high pressure throughout the withdrawal cycle.
- Reservoir pressure will be maintained at a high level. This practice will improve delivery of high-pressure air to the surface equipment, and prevent groundwater from encroaching into the reservoir.
- Concentration of native natural gas in the air flow from the reservoir to the I/W wellheads should be limited by actively monitoring and intervening in the withdrawal of individual wells as required. Wells are expected to perform differently from each other, so project operators will need to identify wells having higher gas concentrations and use operating strategies to limit their impact on the total flow stream.
- Well operation will need to be investigated and reworked at the first sign of impaired performance. Any underperforming well puts a proportionately larger burden on the remaining wells and can have an impact on the total performance of the reservoir.
- High-performing wells should not be over-produced. This could lead to a reduction in capability if one of these wells were to fail.

7.4.6 Compressed Air Pipeline

A 30-inch-diameter pipeline, approximately 2.6 miles long, would be constructed to deliver compressed air from the ECF compressors to the well/reservoir and from the well field back to the ECF generation equipment. Thus the air pipeline would allow bidirectional flow between the ECF and the well pads. The air pipeline design would include cathodic protection, blow-down valves (silenced as necessary), condensate traps/drains to manage water dropout as the air cools in the pipeline, and pipeline "pigging" equipment for maintenance. A 0.3-mile-long air collector/connector pipeline would also be constructed between the east and west well pads.

7.4.7 Wastewater Disposal System

In the base case design, ECF wastewater would be disposed of via two wastewater injection wells. These wells would be used for injection of the produced water from the reservoir. One injection well would be located at the east well pad, and a second at either the ECF site or the west well pad. To connect the ECF to the injection well(s) at the well pads, cooling tower blowdown and other industrial wastewater from the ECF could be piped to King Island for disposal. A wastewater pipeline would be co-located in the same trench as the air pipeline.

7.5 CONCEPTUAL ENGINEERING DESIGN

With the CAES technology (SMARTCAES™) and configuration alternatives (wet cooled with 6-hour compressor re-injection) now selected, the conceptual engineering effort moved in parallel on two fronts:

1. Air Transmission Design and Cost Estimate
2. Energy Conversion Facility (ECF) Plant Design and Cost Estimate

7.5.1 Reservoir Modeling

The King Island Reservoir was selected for potential full field development to support a 300-MW CAES plant. This selection was based on a thorough analysis of all the previous evaluation work discussed in this technical report, including air injection testing and significant reservoir modeling. Numerous sensitivities were tested to determine the most effective well design, bubble building scenario, and strategies to minimize native gas production.

The geological structure of the Mokelumne River formation in the King Island Field can be described generally as consisting of two interconnected lobes. This geological complexity is both an aid and a hindrance to the CAES development. It is helpful in the sense that it provides a developer an opportunity for a sequential development, building a bubble on only one lobe to start operations and then eventually expanding into the other lobe. It is a hindrance in the sense that the influence of one lobe on the other affects both flow dynamics and gas mixing within the reservoir, which adds complexity to the modeling and makes simulation of full operations more complex.

The final development design of the reservoir incorporates a variety of elements and strategies that were evaluated in numerous modeling sensitivity runs:

- Results of the compression testing as incorporated into the reservoir model
- Information received from EPA through the UIC permitting process for the compression testing
- Consideration for the surface restrictions related to well pad placement utilizing a total of 10 acres for well surface disturbance. Due to the aerial extent of the reservoir, two well pads appropriately located could accommodate all of the wells necessary to develop both lobes of the King Island reservoir. (See discussion on well pad layout and design in the "Well Collection System" section later in this chapter.)

The reservoir design process for a full field development commenced in August 2013 immediately after completing the model simulation runs for the compression test. The initial base case assumptions for a reservoir design to support a 300-MW surface facility included the following:

- Air bubble cushion = 5,000 to 12,000 MMscf.
- Withdrawal rate per cycle = 1100 MMscfd over a 10-hour period.
- Injection rate per cycle = 550 MMscfd (50% of withdrawal rate).
- Bubble build period = Approximately 1 year.
- Number of wells = As needed to achieve the total withdrawal rate.
- Well spacing = 2 to 3 acres.
- Maximum well bottomhole injection pressure = 3,000 psia.
- Daily cycle = 10 hour withdrawal, 1 hour rest, 12 hour injection, 1 hour rest; repeat M-F.
- Weekend cycle = Injection for 39 hours to restore bubble size.

Initially the reservoir modeling was completed using a two-phase solvent model (Eclipse 100), where the air was being modeled as an injected solvent into a depleted gas reservoir. This approach was taken to simplify the production history match and operational modeling to focus on flow characteristics of air and water within the reservoir and wellbore. After the base case model had been modified such that the necessary flow characteristics could be achieved, additional refinement was achieved utilizing a fully compositional model (Eclipse 300). This model was used to provide additional data regarding expected mixing of the injected air with the native natural gas in the reservoir and predictions of gas concentration during full operations. This latter modeling is an important aspect of a future CAES operation to ensure that withdrawal operations can be performed safely and meet the technical limitations of the CAES equipment.

After conclusion of the air injection testing, the model parameters were updated to provide a better match with the actual test data. It was determined that the methane concentrations in the withdrawal gas stream were more accurately predicted by utilizing a smaller grid pattern near the wellbore, so where feasible this refinement was used for the subsequent simulations. The previous full field development scenarios were rerun to check performance with the revised model and additional adjustments made based on the analyses of those results.

A detailed report of the testing results and subsequent modeling for the full field development is provided in the "Final Technical Memorandum for Compressed Air Energy Storage—Reservoir Characterization and Full Field Development Model, King Island Gas Field" by WorleyParsons dated September 25, 2015 (see Appendix 7A, Attachment 6, CAES Final Tech Memo FINAL 25 Sept 2015 Rev 0 Full). A summary of the key design parameters is depicted in Table 7-3.

Table 7-3 King Island CAES Full Field Development Parameters

Design Criteria	Parameter
CAES Plant Capacity	300 Megawatt
Air Bubble Volume	9.0 to 10.0 Bscf
Working Volume per Withdrawal	0.5 Bscf (5% of Bubble)
Estimated Time Period for Bubble Build	18 months
Field Withdrawal Rate / Plant Intake Rate	1.1 Bscfd
Cycle Withdrawal Period	10 hours maximum
Total Injection Rate	0.5 Bscfd (50% of deliverability)
Number of Wells	As needed to achieve deliverability
Well Locations	Both East and West Structural Areas
Maximum Bottomhole Pressure	3,000 psia
Minimum Bottomhole Flowing Pressure	1,500 psia
Minimum Wellhead Tubing Pressure	850 psia
Maximum Drawdown at Sandface	200 psi
Maximum Methane Concentration - Plant Intake	2.0 percent
Maximum Methane Concentration - Well Stream	4.0 percent

Following are some of the conclusions from that report related to the development of a 300-MW CAES facility.

1. **Air Bubble Size—**Analysis concluded that an air bubble of approximately 9.0 to 10.0 Bcf at King Island would be sufficient to provide the necessary delivery pressures over the entire operating range and also large enough to keep gas concentrations in the withdrawal air stream within safe parameters. Figure 7-10 shows, for a 9.6 Bcf bubble,

the range of field operating pressures and methane concentrations during the modeled weekly cycling scenario for the first 2 years of operation.

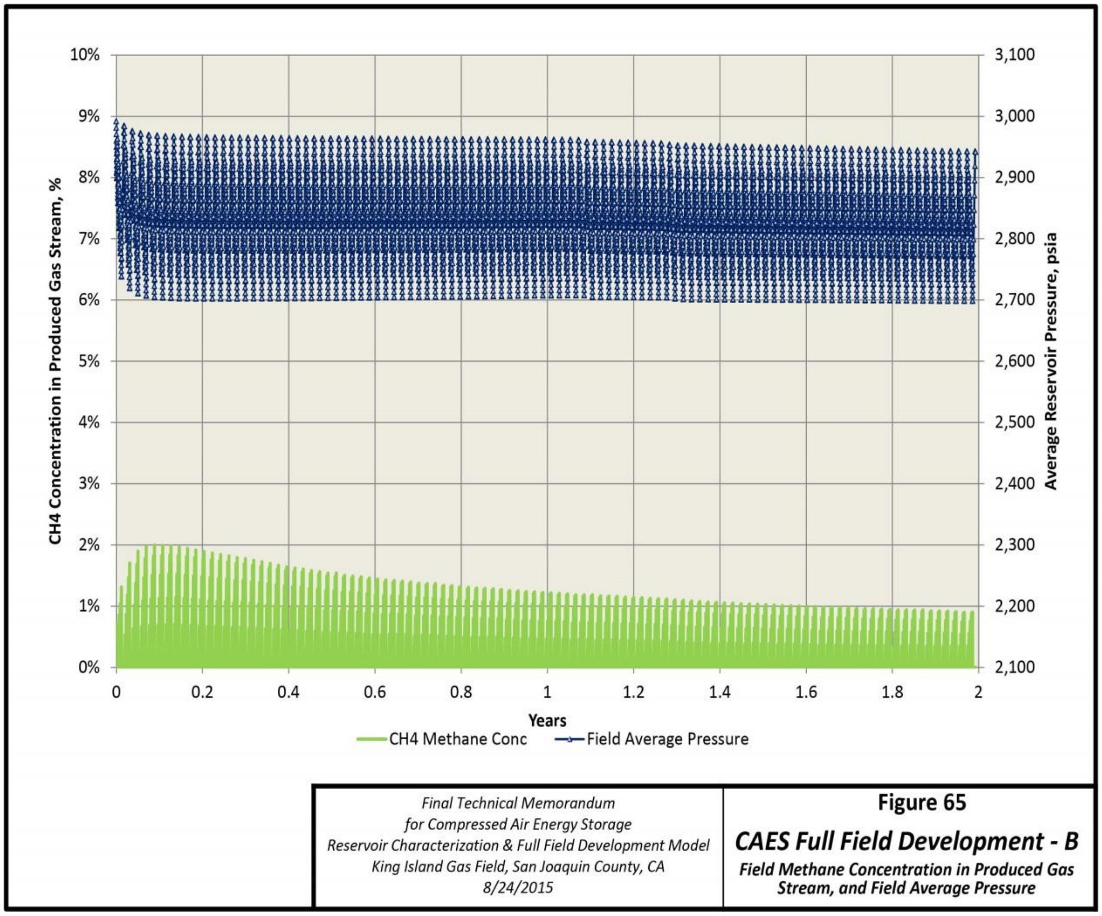


Figure 7-10 Reservoir Pressure and Methane Concentration during Full Field Operation

2. **Type of Injection/Withdrawal (I/W) Well** – Both horizontal and vertical I/W wells were modeled and their performance investigated. Modeling results showed that even though the horizontal wells potentially had better flow performance, the vertical wells were superior in terms of managing the native gas concentration on withdrawal. During the initial bubble build, the vertical wells were much more effective at pushing the native gas away from the wellbore more uniformly across the entire vertical cross-section of the storage zone, and thereby keeping the native gas away from the wellbore on withdrawal.

3. **Bubble Build Period** – The time to build the bubble without physically removing water from the underlying aquifer and staying within the 3,000 psi injection pressure

limitation turned out to be 10 years and 4 months. This is due to the relatively slow rate of water efflux from the underlying aquifer limiting the ability to build sufficient air volume in the desired timeframe. When water withdrawal wells were installed at the perimeter of the reservoir and operated throughout the bubble build period at a rate of 3,200 Bbl/day, the bubble build period was reduced to 1 year and 6 months. Figure 7-11 depicts the bubble building period predicted by utilizing water withdrawal wells.

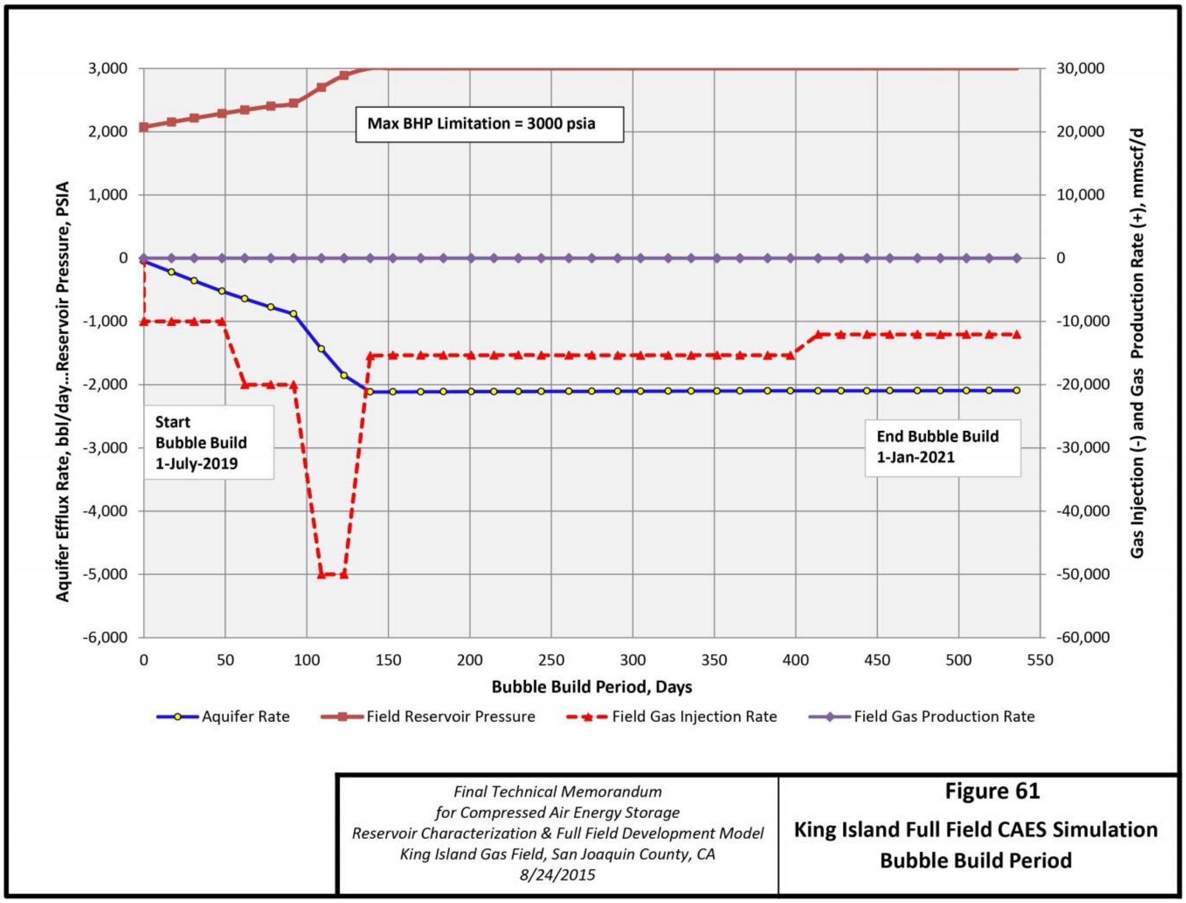


Figure 7-11 Bubble Build Period

Additional sensitivity runs were made to evaluate strategies for sweeping the native natural gas away from the I/W wells, thereby minimizing the impact of the gas concentration during withdrawal. These strategies included minimizing the number of injection wells during the bubble build to concentrate the bubble, control the growth, produce as much of the native gas as possible before air injection commenced. Additionally, the project team evaluated an injection scenario that utilized an initial nitrogen buffer before the start of air injection to minimize the mixing of the native gas with air. The most effective technique evaluated utilized an "inside-out" well development plan where a single I/W well is located at the top of each lobe of the structure (see geological discussion above) and then wells are added as the bubble expands. This bubble-building methodology pushes the native gas further to the outer edges of the reservoir, providing benefit during the early years of operation. The collective native gas concentration from all I/W wells during each withdrawal cycle of the first 2 years of operation is shown in Figure 7-11 above. The maximum native gas concentrations from individual wells during the first 2 years of operation are depicted in Figure 7-12.

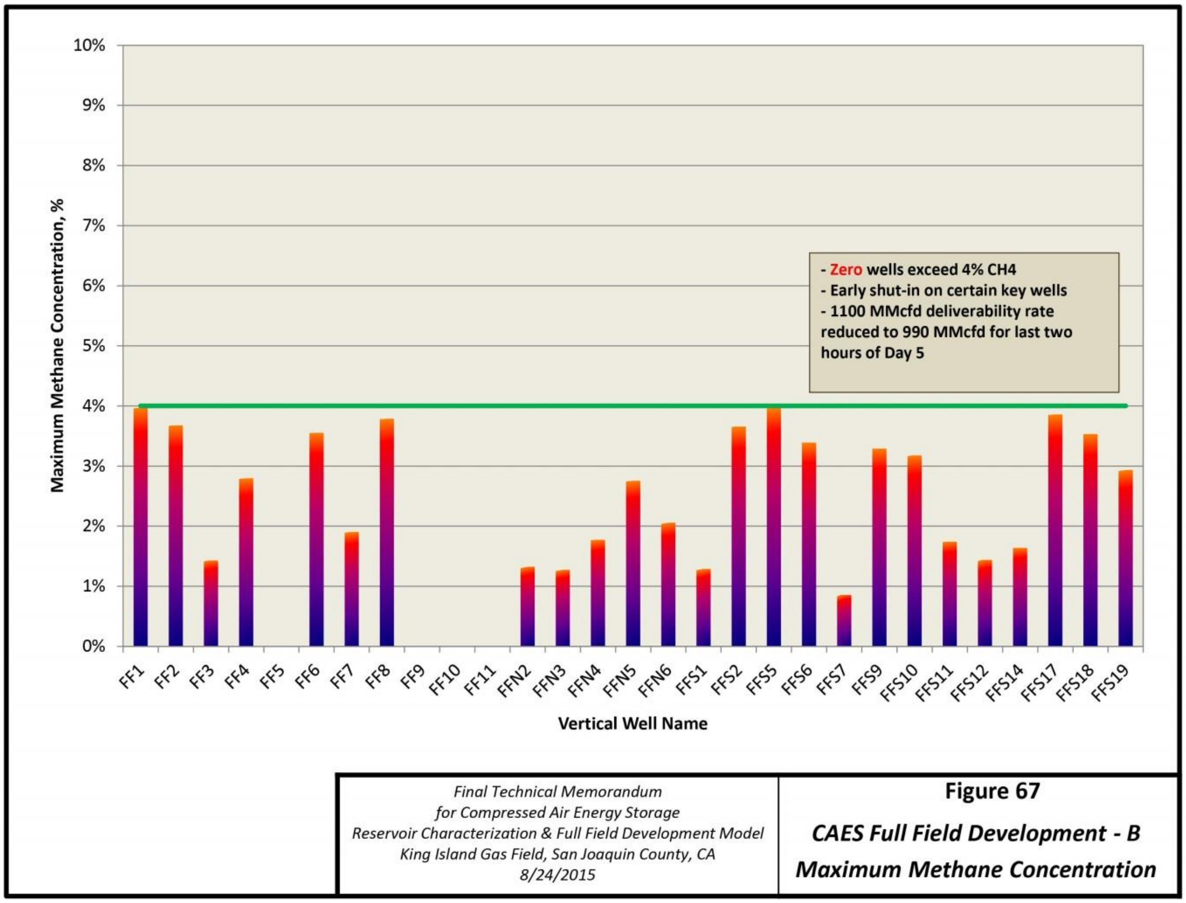


Figure 7-12 Maximum Native Gas Concentrations from Individual Wells During First 2 Years of Operation

4. **Water Production** – After the bubble has been developed, water production is not expected to be a significant factor with estimates of less than 300 barrels per day total over the two-year operating period (Figure 7-13).

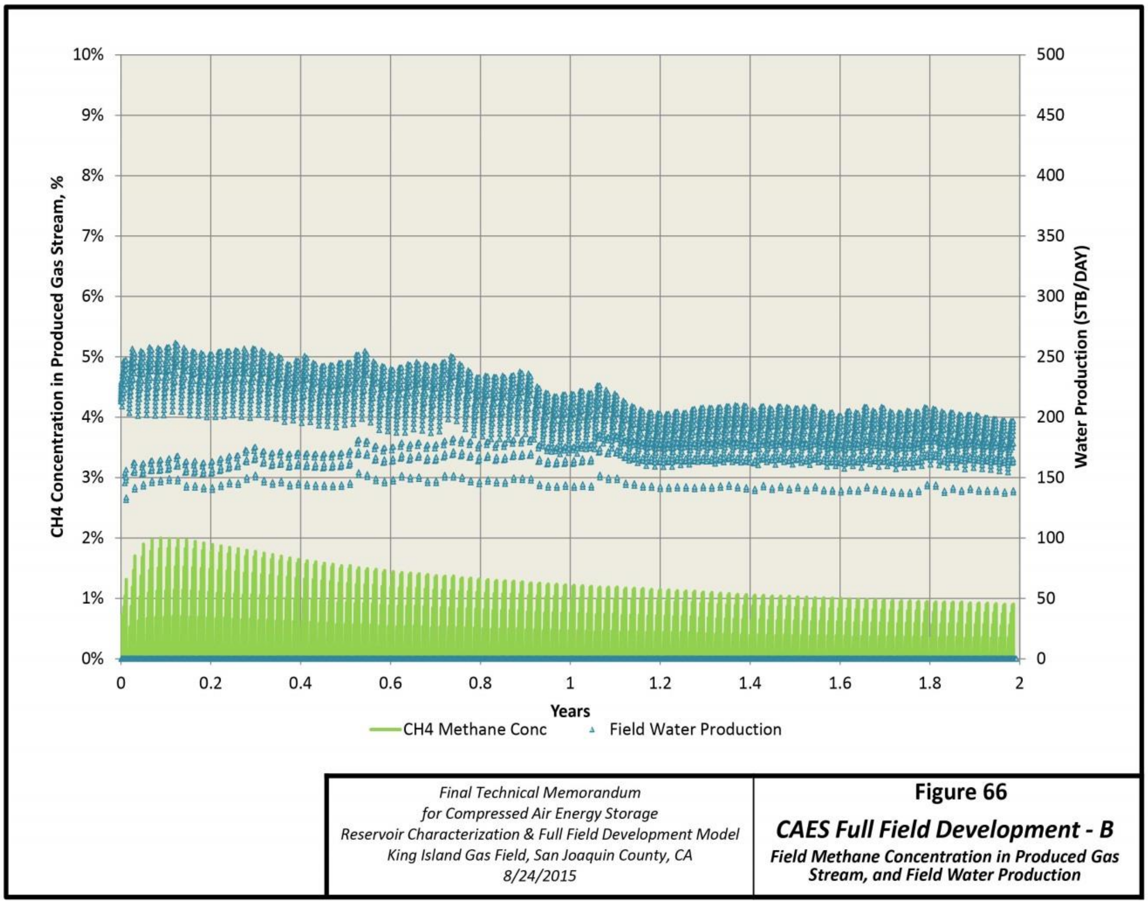


Figure 7-13 Water Production and Maximum Native Gas Concentrations

Additional sensitivity cases were run to investigate what would happen if one or more re-injection cycles were missed or skipped during a week's operational period. The model results showed that there is a delicate balance in keeping the native gas away from the wells during the withdrawal cycles. Re-injection is critical to controlling the methane concentrations by well. Only 2 or 3 days of injection may be skipped before methane concentrations begin to increase to unacceptable levels in some wells. If the injection deficit is made up by subsequent over-injection, the model predicts that the operations recover to "normal" as the methane concentrations come back down to previous levels.

7.5.2 Air Transmission System Design and Engineering

Based on the simulation/modeling results, an Air Transmission System Conceptual Design (see WorleyParsons Air Transmission System Conceptual Design and Cost Estimate, Appendix 7A, Attachment 4, WP Conceptual Design ATS) was created, which captured both the air transport pipeline and the well collection system (collectively known as the Air Transmission System). To identify potential changes if the alternative ECF site is utilized, WorleyParsons created the Air Transmission System Conceptual Design and Cost Estimate Addendum (see Appendix 7A, Attachment 2, WP Conceptual Design Addendum Alt ATS).

The conceptual design is based on the preliminary modeling discussed in Section7.5.1 of this report. The purpose of the system is to move compressed air from the Energy Conversion Facility (ECF) into the storage reservoir and to later transport high-pressure motive air from the reservoir back to the ECF for power generation (see Figure 7-14).

Figure 7-14 Overview of Air Transmission System

The Air Transmission System would have the following features:

1. **Well Collection System:** Two well head pads consisting of up to 30 air injection/withdrawal wellheads, four water withdrawal well heads, up to two water injection well heads, and supports and piping for ancillary equipment.
2. **Air Pipeline:** 2.6 miles of 30-inch pipeline.

The Air Transmission System was conceptually designed based upon the process flow conditions shown in Table 7-4.

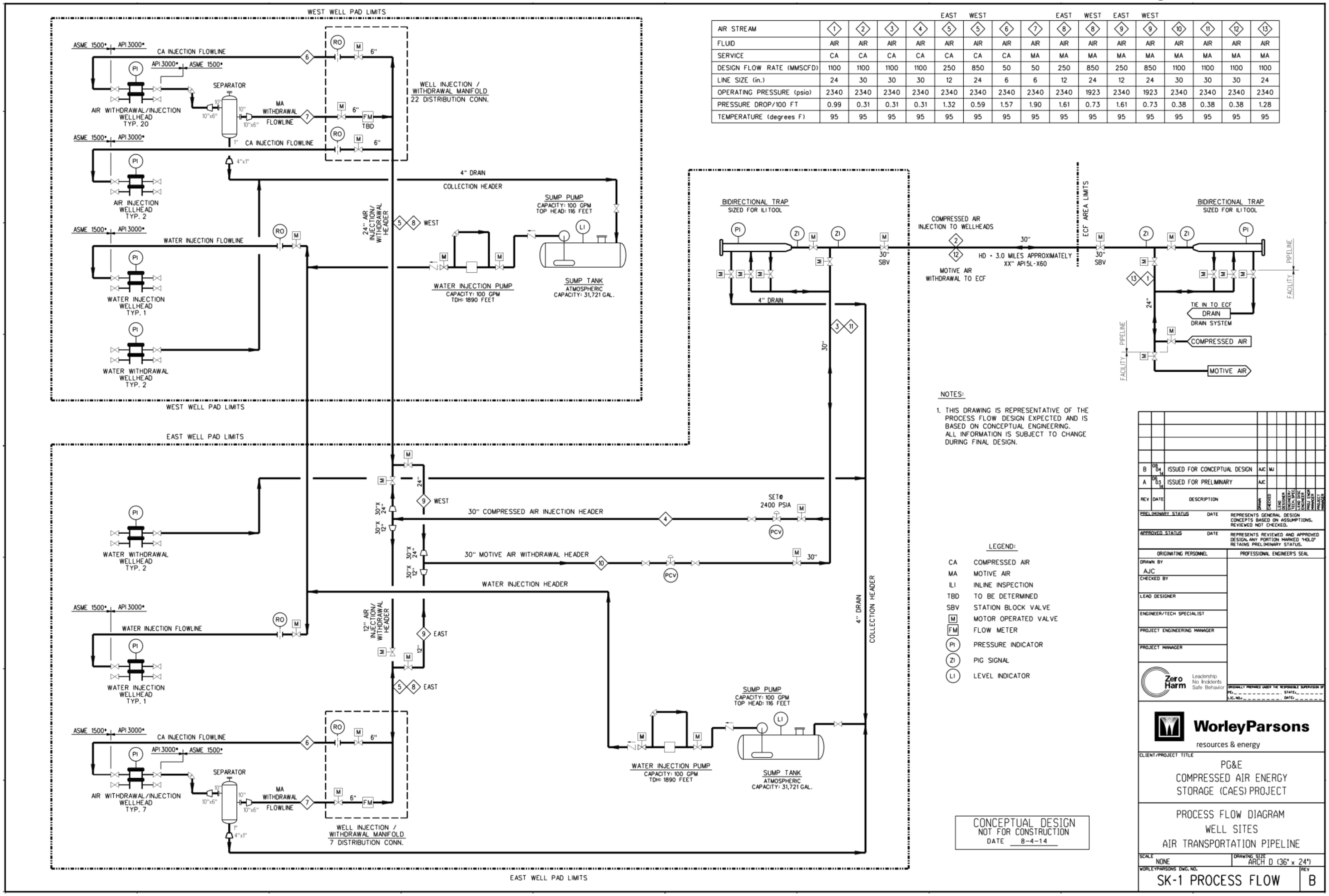
Table 7-4 Process Flow Conditions

Transported Fluid	**Air**
Compression discharge pressure, psig	2900
Injection flow rate, MMscfd	1100
Compression discharge temperature, °F	100
Withdrawal air pressure at wellheads, maximum, psia	2300
Withdrawal air flowrate, maximum, MMscfd	1100
Withdrawal temperature, °F	100
Water flowrate during the 18 month bubble building period, bbls/day	12,800
Water flowrate during operation, maximum, bbls/day	1458
Minimum hydrocarbon content by volume	0%
Maximum hydrocarbon content by volume – Combined Flow Stream	2%
Maximum hydrocarbon content by volume – Individual Well	4%

Other requirements/standards that were assumed for the report (codes, civil/structural requirements, electrical, etc.) are identified in the Air Transmission System Conceptual Design (see WorleyParsons Air Transmission System Conceptual Design and Cost Estimate) (see Appendix 7A, Attachment 4, WP Conceptual Design ATS).

Figure 7-15 shows a conceptual process flow diagram for the entire Air Transmission System. The overall process consists of the following:

1. For injection, air would be compressed to 2900 psig at the ECF and moved at a flowrate of 1100 MMscfd through 2.6 miles of 30-inch pipeline to the east wellhead facility. From there, the air would be moved into 12–inch headers at the east well pad and 24–inch headers at the west well pad. The headers would have a six-inch injection line to each air wellhead. The injection rate would be 50 MMscfd/well.
2. For withdrawal, air at 2340 psig would be released from the wells through the withdrawal piping to the headers. Each well would have a packaged equipment unit through which the withdrawn air would flow to remove water and particulates. From the headers, the air would move into the connection piping and through the 30-inch pipeline to the ECF. The headers and the 30-inch pipeline are bidirectional.
3. A water removal process would be located at the well pad storage area. Water would be drained from the main 30-inch pipeline receiver and from the water removal vessel within the packaged equipment at each well. Water is also expected to be processed from water withdrawal wells during the bubble building phase of the operation. All water would drain through the collection piping into a sump tank. From the sump tank at each well pad, it would be pumped into the water injection wells.



					EAST	WEST			EAST	WEST	EAST	WEST				
AIR STREAM	1	2	3	4	5	5	6	7	8	8	9	9	10	11	12	13
FLUID	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR	AIR
SERVICE	CA	CA	CA	CA	CA	CA	CA	MA	MA	MA	MA	MA	MA	MA	MA	MA
DESIGN FLOW RATE (MMSCFD)	1100	1100	1100	1100	250	850	50	50	250	850	250	850	1100	1100	1100	1100
LINE SIZE (in.)	24	30	30	30	12	24	6	6	12	24	12	24	30	30	30	24
OPERATING PRESSURE (psia)	2340	2340	2340	2340	2340	2340	2340	2340	2340	1923	2340	1923	2340	2340	2340	2340
PRESSURE DROP/100 FT	0.99	0.31	0.31	0.31	1.32	0.59	1.57	1.90	1.61	0.73	1.61	0.73	0.38	0.38	0.38	1.28
TEMPERATURE (degrees F)	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Figure 7-15 Air Transmission System Process Flow Diagram

Well Collection System

The well head pads would occupy up to 10 acres. Figures 7-16 and 7-17 outline the conceptual plot plan for each of the well head pads.

The west and east well head pads would be elevated one foot above the well pad, which is expected to be elevated two feet above existing grade. The well heads would be drilled directionally from these areas. The high-pressure air collection system, connecting the wells, would consist mainly of 6- and 12-inch piping. A water removal and particle filtration vessel would be installed at each wellhead, with a water collection system to take water removed from the process flow into a sump where it would later be re-injected into the formation via one of the water injection wells.

Each well pad stream would connect to a 30-inch air header common to both pads, resulting in two 30-inch headers, with one for injection and one for withdrawal air. Both headers would be routed to the bidirectional trap prior to the transmission line to the ECF. The 30-inch line pipe within and adjacent to the mainline valves would be heavy wall.

All valves would be motor operated for remote control from the ECF. Each well head pad would have a control/motor control center (MCC) building and a small warehouse. The control/MCC building and associated transformers are expected to be elevated 12 inches above the 100-year flood event elevation.

The conceptual design assumes that the well pad operation will not continue during a flood event but is instead designed to safely shut down and protect key, critical electrical equipment (the facility can be designed to continue operations).

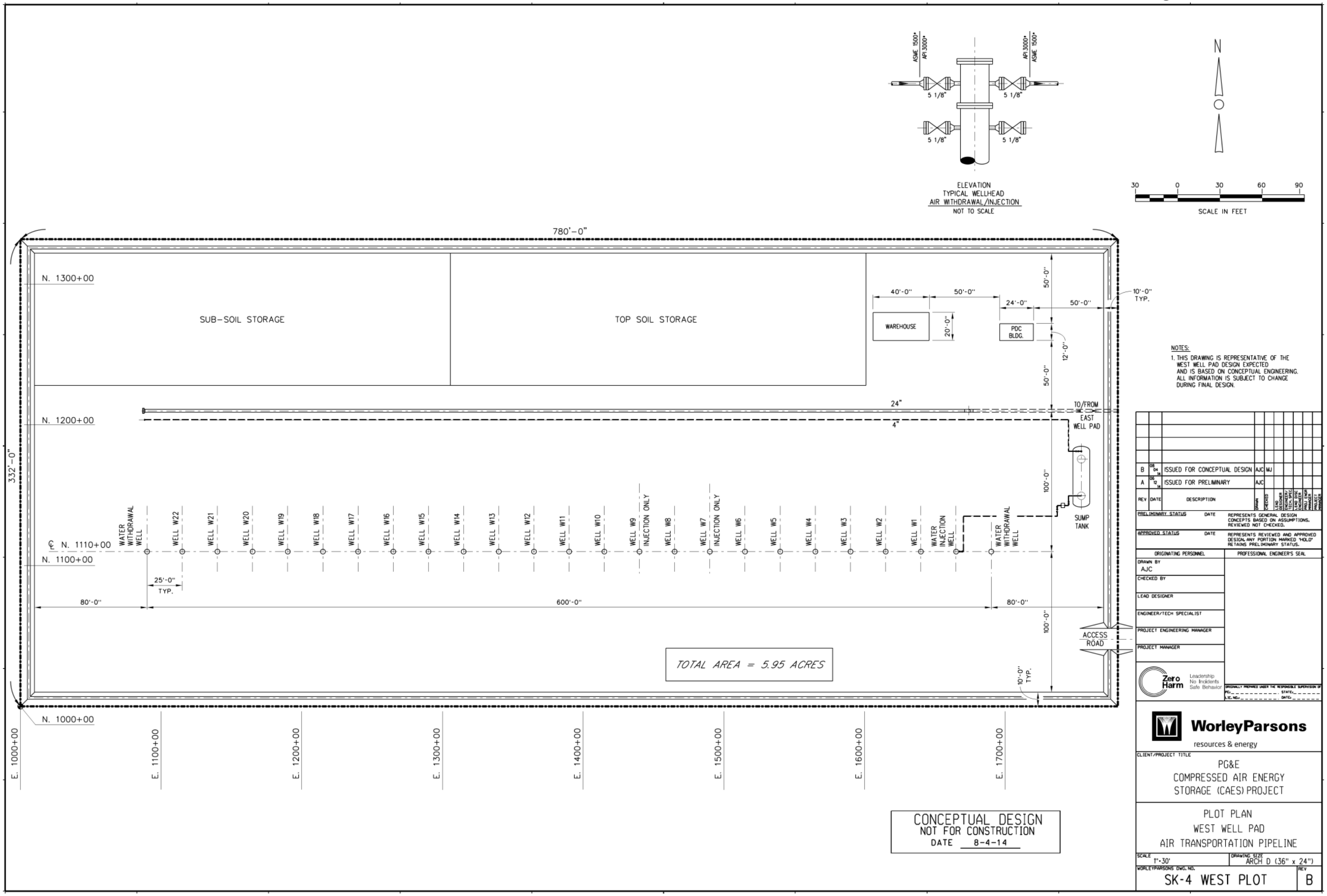


Figure 7-16 West Well Head Pad

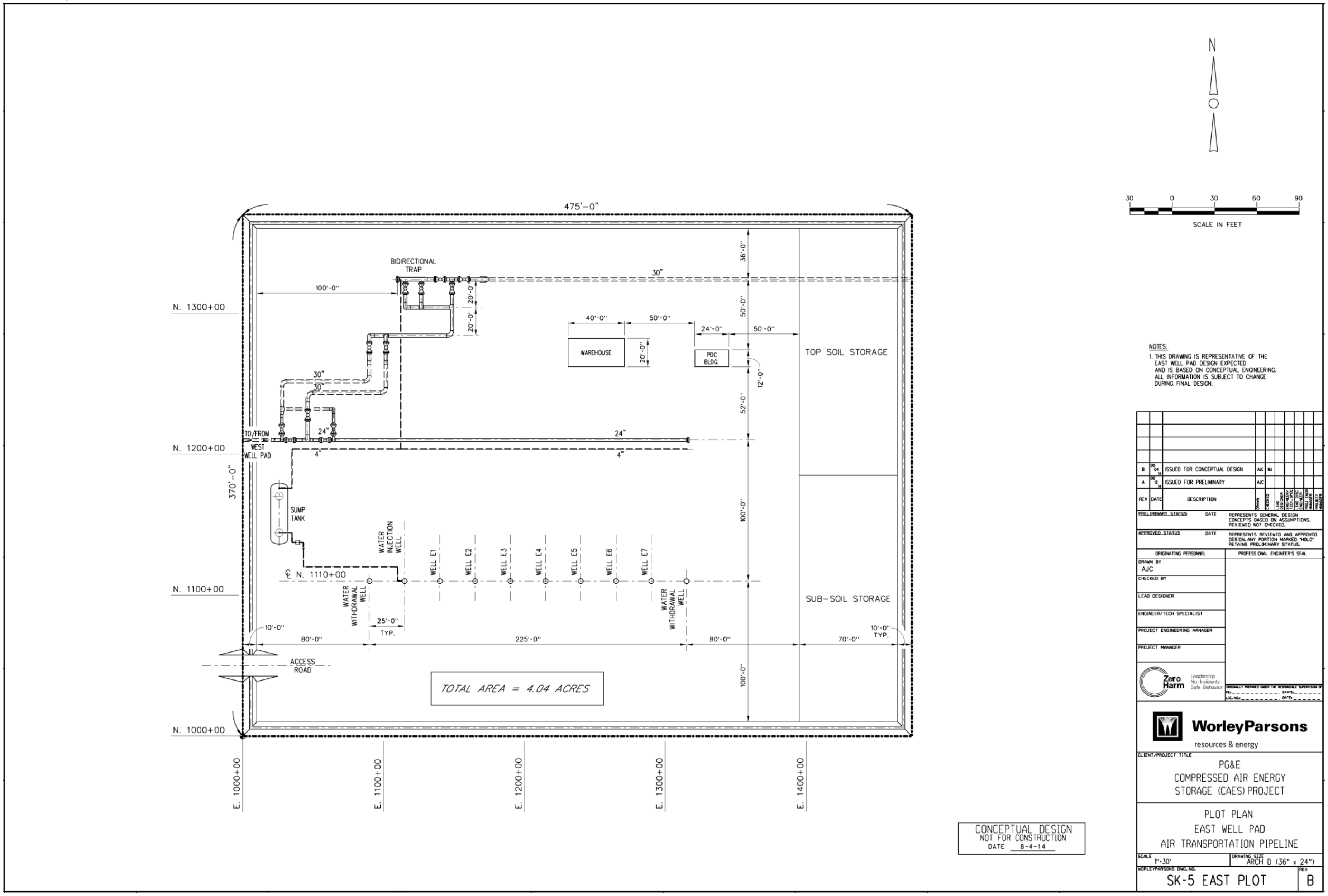


Figure 7-17 East Well Head Pad

Injection/Withdrawal Wells

The simulation results of various well completion designs showed that straight, directional, or highly deviated wells are preferred to horizontal well designs. Primarily this is because the directional and highly deviated wells were found to provide better control over the native gas concentrations in the withdrawal flow stream than horizontal wells.

Regarding casing requirements, EPA has indicated that, for future injection permits, they will require two separate runs of casing to be cemented from below the underground sources of drinking water (USDW) to the surface. A well program for the I/W wells was developed that calls for 20-inch surface casing, 13-3/8-inch intermediate casing to approximately 3,500 feet true vertical depth (TVD), and then 9-5/8-inch casing set to the top of the reservoir. The reservoir is completed with a well screen and gravel pack and 5-½-inch tubing set on a packer to within 50 feet of the top of the reservoir. Casing and tubing lengths will be longer for more highly deviated wells. Each I/W well is designed for a flowrate of up to 50 MMCFD, and it was determined that 5-½-inch tubing was adequate for this purpose without significant pressure loss. At atmospheric conditions, the combustible range for natural gas in air is typically 5% to 15%; however, at the anticipated operating pressures of the CAES facility, the lower concentration limit is reduced to approximately 4% CH_4 in air. For this reason, keeping the gas concentrations in the withdrawal flow safely below 4% at all times is critical for safe operation of the surface facilities.

The limitation on natural gas concentrations in the withdrawn air is an important design consideration for a CAES reservoir, unlike development of a natural gas storage reservoir. Spacing of the I/W wells can play a key role in this regard. Tighter spacing may provide for a better sweep of the natural gas during the bubble build period, but could lead to interference and flowrate constraints later during operations. The modeling results indicated that broader well spacing tends to leave trapped native gas between wells, which later can become an issue during withdrawal operations. The optimal well spacing takes into account the following factors:

- Bubble build plan, which includes injection rates, total volume, schedule, and injection pressure limitations.
- Maximum tolerable native gas concentration in the withdrawal stream.
- Overall bubble size.
- Anticipated operating plan, including capacity ramp-up considerations over the first few months of operation.
- Total number of I/W wells for the planned full field development (see discussion below regarding the number of I/W wells required).

Water Withdrawal Wells

One of the key findings from the base case modeling work is that reservoir pressure is affected by a partial water drive. In other words, as gas was produced from the reservoir initially, the pressure decline was dampened by water influx into the reservoir from the underlying aquifer. Over time, the reservoir pressure has continued to rise due to the continued water influx. This response was relatively slow, and the modeling revealed that the effort to push the water from out of the reservoir and back into the aquifer will likely be slow as well. With an assumed 3,000 psi maximum reservoir pressure constraint, a developer could either inject at a rate that the water will naturally efflux from the reservoir (push the water back with pressure), or physically remove a volume of the water from the invaded zone in the reservoir. Based on the modeling results, the base case time constraint of approximately one year to develop a 9.0 to 10.0 Bcf air bubble could not be achieved without the physical removal of some water from the reservoir during the bubble build period.

The modeling runs that utilized the water removal strategy during the bubble build period involved four water withdrawal wells located on the perimeter of the storage reservoir, operating at rates of approximately 3,200 Bbl per day each. By utilizing this water removal rate and a maximum injection pressure of 3,000 psi, the base case bubble size and time constraints were able to be achieved (see King Island Progress Report_01-29-2014 FullField attachment, Appendix 7A, Attachment 7, King Island Progress Report 01-29-2014 FullField.pdf). The produced water would be re-injected into EPA-approved disposal wells completed in zones deeper than the USDW (see the discussion below). Exact placement of the wells within the formation is not critical so long as they are completed outside of the intended air bubble diameter and well below the original gas/water interface. A plot of the reservoir pressure and water removal rates during the bubble period is provided in Figure 7-11 above.

Water Disposal Wells

Initially water disposal wells will be needed to inject the water withdrawn during the air bubble build period. Once the bubble has been established and the reservoir is fully operational, waters produced during normal operations may need to be disposed. Reservoir modeling estimates that initial daily volumes of produced water during withdrawal operations will be up to 12,000 Bbl/day, and stabilized volumes after a few months are estimated at 5,000 Bbl/day. This water would be produced with the withdrawal air and separated from the flow stream during withdrawal operations. This produced water, along with non-hazardous water from the power generation process, will need to be disposed, presumably utilizing the same water injection equipment as during the bubble build period.

In the vicinity of King Island, the Starkey formation is deeper than the USDW, and properly completed water disposal wells would not interfere with the air storage operations in the Mokelumne River Formation (MRF). Disposal of produced waters into the Starkey formation would require one or more disposal wells, tankage for temporary storage, properly sized pumps for this purpose, and the interconnecting piping between the equipment location and the disposal wellsite.

Modeling results indicate that two water disposal wells will be required. (Both water disposal wells could be located at the wellhead pads, or one could be located at a wellhead pad and the other at the ECF location.) These wells would be sufficient to handle the anticipated volume of water withdrawn from the MRF during the bubble build period, as well as the water produced during normal operations, both from the reservoir and wastewater from the ECF. (See WorleyParsons Air Transmission System Conceptual Design and Cost Estimate, which includes an estimate for a 4-foot water pipeline, which would be co-located in the same trench as the air pipeline; this water pipeline would allow for wastewater to be sent from the ECF to a water injection well located at the wellhead pad or for water produced at the wellheads to be sent to a water injection located at the ECF location.) The Worley/Parsons Air Transmission System Conceptual Design and Cost Estimate (see Appendix 7A, Attachment 4, WP Conceptual Design

ATS) includes a preliminary produced water system process flow diagram (see Figure 7-18). During routine operations, one well should be capable of handling all of the produced water volume with the other well in standby. The design of the water disposal wells is very similar to that of the I/W wells, utilizing 20-inch surface casing, 13-3/8-inch intermediate casing, 9-5/8-inch-long string, and 5-½-inch tubing. The completion zone will be in the Starkey formation, the top of which is at a depth of approximately 6,300 feet.

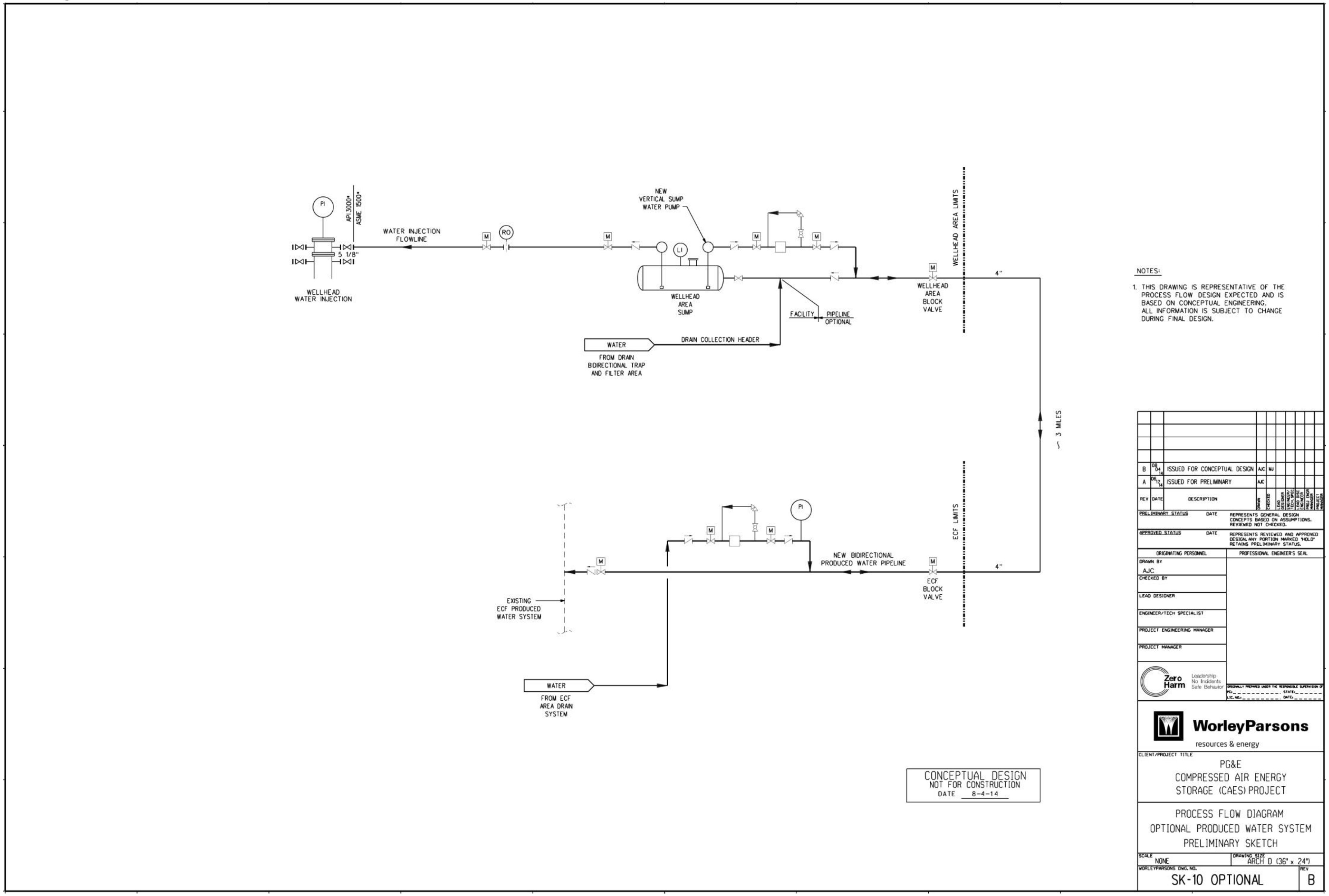


Figure 7-18 Preliminary Produced Water System Process Flow Diagram

Observation Wells

Two existing gas production wells, the Piacentine #1-27 well and the Citizen Green #1 well, are completed in the King Island reservoir and could be used for observation of reservoir conditions, subject to permitting requirements by the EPA (the Piacentine #2-27 well, constructed as part of the core drilling effort, could also be considered as an observation well if desired). They would be used primarily to monitor pressure and possibly native gas concentration. These wells were used as pressure observation wells during the compression testing (as discussed in Chapter 6, "Air Injection Test and Analysis"). Very little remedial work is assumed to be needed on these wells to comply with EPA requirements.

Number of Wells

Up to 30 vertical, directional, or highly deviated I/W wells will be required to achieve the very high rates required to support a 300-MW CAES facility and maintain native gas concentrations well below the 4% threshold. At peak withdrawal, this rate averages 34 MMCFD per well, which is reasonably achievable with this type of well design. Some wells are expected to perform much better, some worse.

One of the keys to individual well performance will be the effect of the water production on the air flowrates. Water can affect the wells' performance in multiple ways, but primarily it will increase the hydrostatic head of the withdrawal column in the wellbore, reducing the effective wellhead pressure. Water could also possibly migrate fine-grained reservoir material towards or into the wellbore, providing a mechanical barrier to flow. The reservoir model can account for the hydrostatic impact of the water production, but not the migration of fines within the reservoir.

In summary, the total number of wells required is as follows:

- I/W wells – 30
- Water Withdrawal wells – 4
- Water Disposal wells – 2
- Observation wells – 2 existing

Air Pipeline Design

An approximately 2.6-mile underground pipeline would be constructed between the ECF and the storage reservoir. The pipeline would be designed for bidirectional flow—transporting compressed from the ECF location to the reservoir/well pads, and moving motive air from the reservoir back to the ECF to generate power.

The pipeline would be 30-inch outside diameter pipe with a 2-inch wall thickness. The estimated maximum allowable operating pressure would be 2900 psi. Block valves would be included at the origin and destination spots. Corrosion protection, via an impressed current cathodic protection system, would be utilized for when the pipeline is in service.

To assist with pipeline maintenance and inspection, a bidirectional launcher/receiver would be installed at each end of the pipeline. The launcher/receiver unit would include a pipe section with a larger diameter pipe and closure and block valves for easy access; it would be sized for the insertion and removal of cleaning pigs and in-line inspection tools.

Alternative Reservoir Design

In lieu of removing large quantities of water from the reservoir during the bubble building period, simulations were completed to evaluate the effectiveness of alternative strategies. The end result of these evaluations was Case 4B1, which involves a staged development plan (see Figures 7-19 and 7-20). The plan starts with methane production only from eight perimeter wells in the west lobe, followed by air injection into the center of the west lobe for a period of 32 months. This approach then allows the startup of a 150-MW CAES facility, operating from the west lobe. At the same time, air injection is commenced in the east lobe. Approximately 18 months later, air withdrawal can commence from the east lobe, so that a full 300-MW facility can be operated. This type of stepped development has the following advantages:

- Eliminates the need for the water withdrawal wells, reducing both capital and operating costs during the bubble build.
- Reduces the EPA permitting requirements by eliminating the additional wells.
- Minimizes the methane remaining in the reservoir, which should reduce the native gas concentrations during withdrawal.

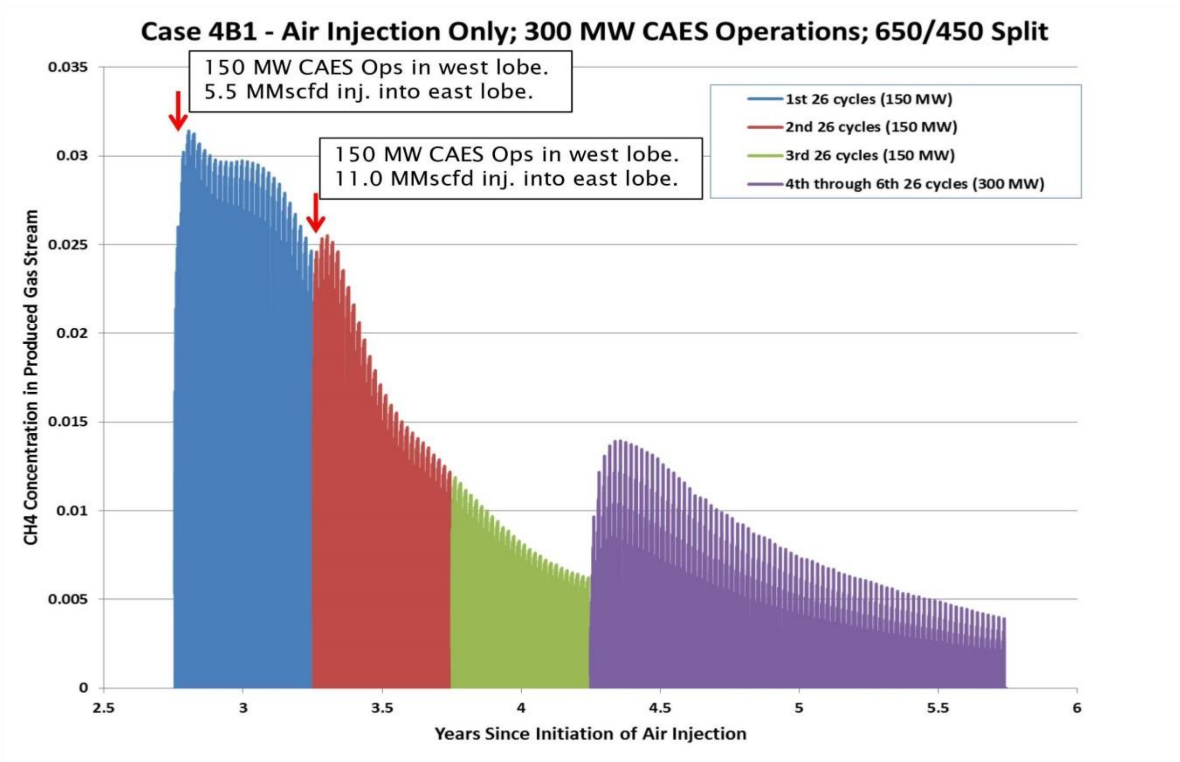


Figure 7-19 Case 4B1 Methane Concentration

As seen in Figure 7-20, the field water production rate for Case 4B1 is extended to run another 78 weeks (red lines). The water production rate gradually decreases throughout the entire 78-week run.

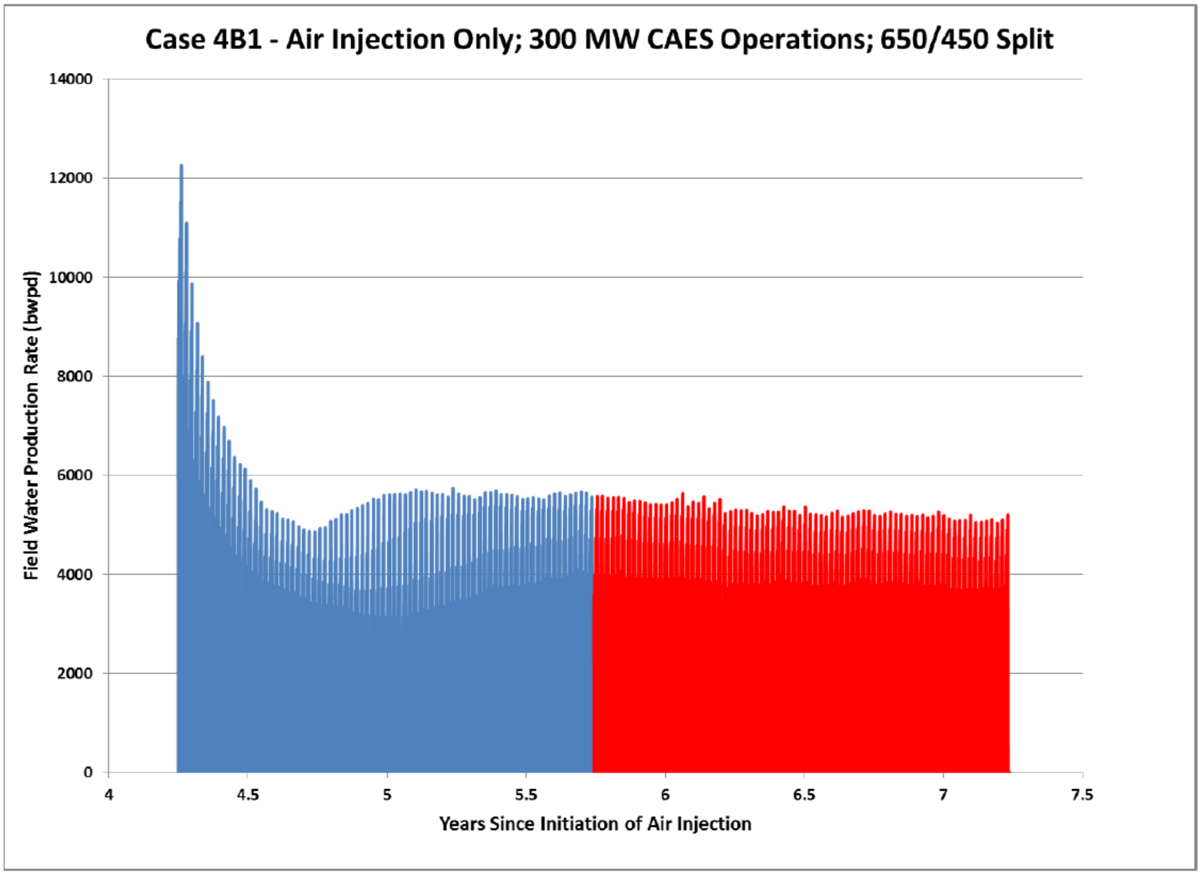


Figure 7-20 Case 4B1 Field Water Production Rate

The key disadvantage of this alternate scenario is the extended timeline, which is partially offset by pushing a portion of the development capital to later in the project timeline. A summary of this case is provided in the King Island Full Field Modeling presentations of September 3, 2014 and September 10, 2014 (see Appendix 7A, Attachment 8, King Island Progress Report 09-03-2014 FullField Case 3B1.pdf; and Appendix 7A, Attachment 9, King Island Progress Report 09-10-2014 FullField Case 4B1.pdf).

7.5.3 ECF Conceptual Design and Engineering

The CAES facility includes three major components:

1. Intake and compression of ambient air
2. Transmission and storage of compressed air
3. Transmission and expansion of stored motive air for the purpose of generating electricity

The ECF is the central facility from which all three components of the process will be controlled. In addition, all process operations, except transmission and storage, will be performed at the ECF. Figures 7-21 and Figure 7-22 show the ECF General Arrangement and Elevation Views developed for the project.

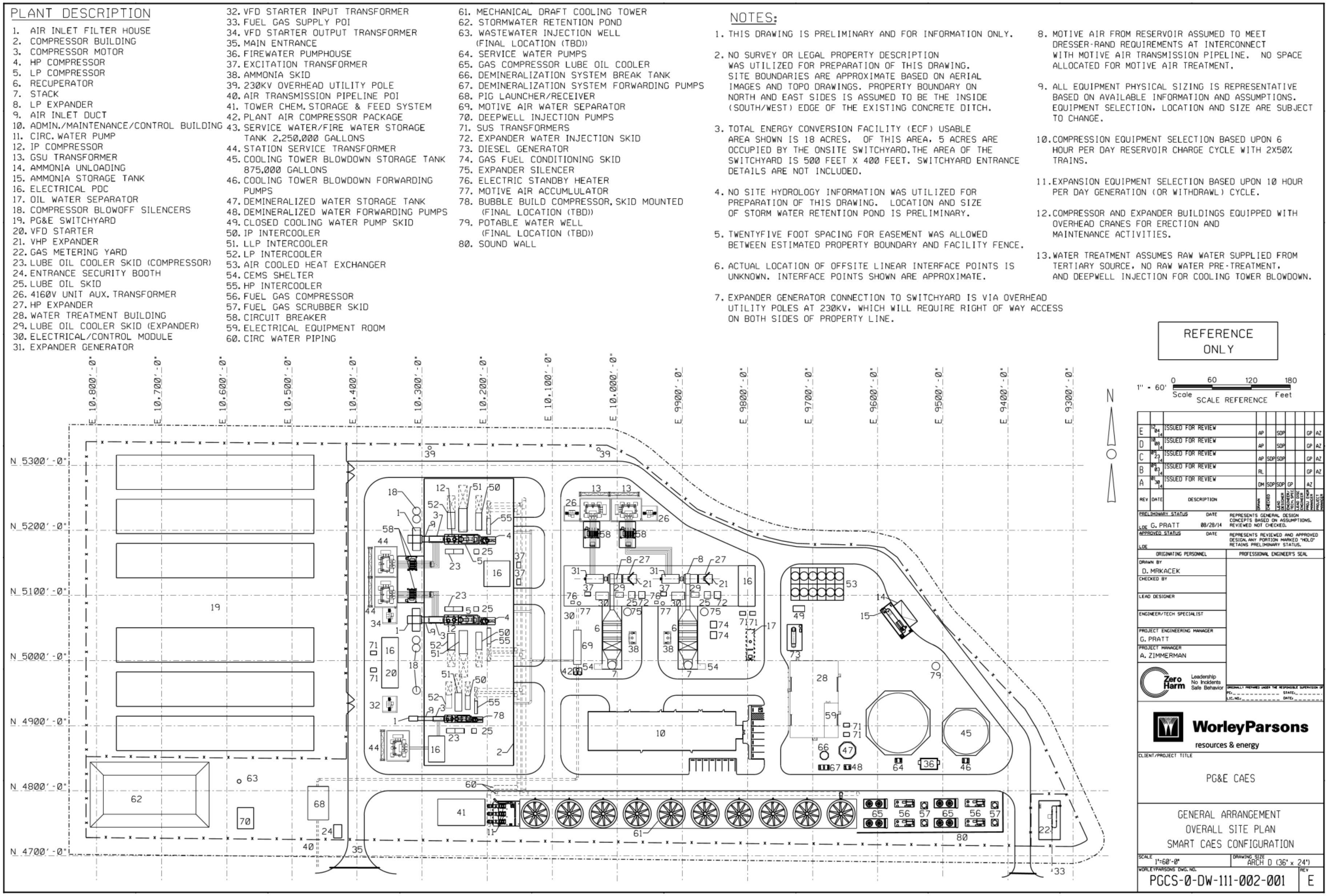


Figure 7-21 ECF General Arrangement

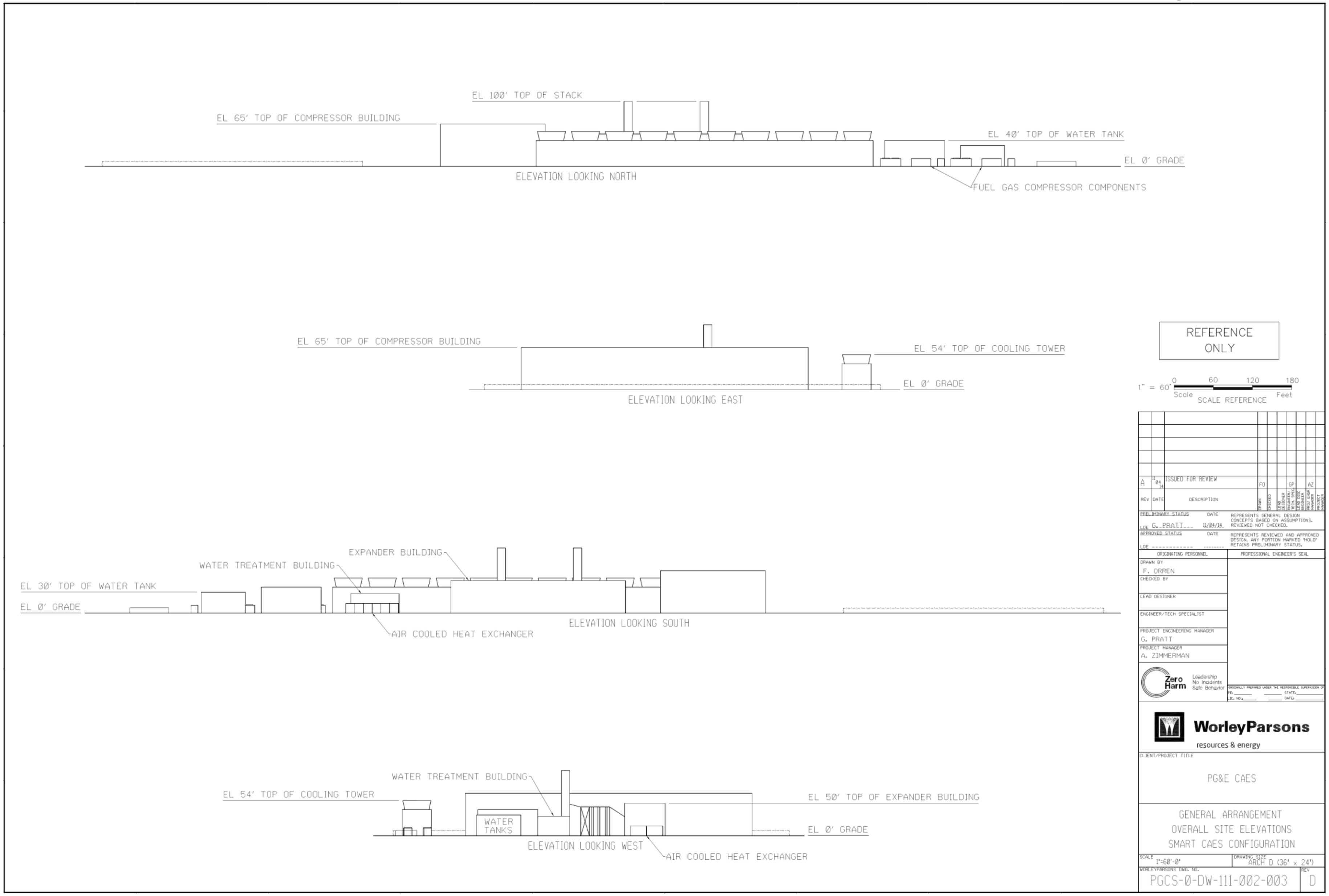


Figure 7-22 ECF Elevation View

The compressed air energy cycle will consist of two processes of an enhanced simple cycle. First, ambient air will be compressed to high pressure and piped through the Air Transmission Line (ATL) to the Air Storage Facility (ASF) for storage. Second, when needed, the air will be withdrawn from the ASF through the ATL to the ECF expansion turbines for generating electricity. The primary distinction between the CAES process and a typical simple cycle combustion turbine is that in CAES the compressor and expansion turbine are physically separated to allow for temporary storage of the compressed air, and the compressor is spun by an electric motor using grid power, instead of being spun by the turbine. All of the work of the CAES turbine is used to produce useful power output. This results in a relatively low heat rate (fuel input divided by turbine output) for CAES, if the energy from the grid used to spin the compressor is not included in the calculation. The rationale for not including the compression energy in the CAES heat rate calculation is that the power from the grid might come from non-fossil fueled sources, e.g., from wind or solar resources.

ECF Operating Modes

The ECF will have a separate, electrically driven compression cycle and a natural gas-fired expansion cycle, and will include all of the auxiliary systems necessary to support the compressed air energy storage process operations. The expansion-generation trains will consist of two Dresser-Rand SMARTCAES™ high-pressure turbo-expanders, equipped with waste heat recuperative heat exchangers, low NOx combustors, selective catalytic reduction (SCR), and oxidation catalyst equipment. The compression trains will include two Dresser Rand high-pressure, three-stage compressors with integrated shell-and-tube heat exchanger intercoolers, shell-and-tube heat exchanger aftercoolers, and inlet air filtration units.

In addition to the primary compression system, the CAES process would require a separate 15-MW compressor for the initial fill of the storage reservoir. This compressor, also referred to as the “bubble-building” compressor (BBC), could also be used during normal operations for replenishing small volumes of storage.

Compression

During normal compressor operation, both compressor trains will be used to charge the reservoir with compressed air. Each compressor train is expected to operate at a final discharge pressure of 2,835 psia and a mass flow rate of 420.4 lb/s at the design conditions. The actual mass flow rate will vary according to ambient conditions. The wet cooling tower and circulating water system must be operated concurrently with the compressor trains to remove heat from the compressed air stream (via inter/aftercoolers between stages of compression), thereby improving compressor train efficiency.

Expansion

During maximum power generation, both expander trains will operate to provide power to the grid. Each expander train is rated at 158 MW gross power output, given a compressed air supply pressure of 2,128 psia at the recuperator inlet and a mass flow rate of 402.7 lb/s at the Dresser-Rand equipment interface.

Simultaneous Compression and Expansion

The compression and expansion trains are capable of simultaneous operation to generate power. This functional capability was included in the conceptual design to allow for the seamless transition from a “charging” state to a “discharging” state. Charging is defined as the time during which the compression plant is operating and injecting (i.e., charging) air via the ATL to the ASF. Discharging is defined as the time during which air is released/withdrawn (i.e., discharging) from the reservoir and used for generating electricity. During simultaneous operation, the final discharge pressure and flow rate of compressed air from the compression trains will vary as required to match the demands from the expander trains.

Market conditions can change rapidly, and having the ability to seamlessly transition from one mode of operation to the other is believed to have value to the grid operator. How the CAISO grid operator views the CAES unit could change if the unit were to lack the ability to simultaneously transition from charging to discharging (or vice versa). Each day, the CAISO purchases—or each Load Serving Entity (LSE) within the CAISO control area self-provides—certain products to cover their load forecasts/obligations. Those products are: Regulation Up, Regulation Down, Spinning Reserves, and Non-Spinning Reserves. For example, a 300-MW gas-fired, combined cycle unit that operates at a minimum load of 120 MW could provide 180 MW (300 MW – 120 MW) of Regulation services, which would allow the CAISO to operate the unit up or down between the 120 MW and 300 MW operating points, based on grid conditions.

A CAES facility with the ability to operate the compression and generation simultaneously and transition from one mode of operation to the other would most likely be viewed as providing ancillary services from its Pmax generation of approximately 316 MW to its Pmax compression injection of approximately -275 MW, in total a range of 591 MWs. This type of seamless transition from generation to injection would need to be confirmed with the CAISO, but given the increasing amounts of intermittent renewables and the necessity to respond quickly to unexpected swings in load, this mode of operation could be extremely valuable.

Compression and Generation (Expansion) Process and Performance

The ECF includes the compression equipment, generation (expander) equipment, and various auxiliary systems necessary for the operation of the facility (cooling, water treatment, emissions control equipment, electrical systems, control systems, etc.). The WorleyParsons Conceptual Design and Cost Estimate Report (see Appendix 7A, Attachment 5, WP Conceptual Design ECF) includes a detailed description of the entire ECF, including these systems. This section discusses the conceptual design and performance of the compression and generation (expansion) process.

Compression Process Description

The compression process is illustrated in Figure 7-23.

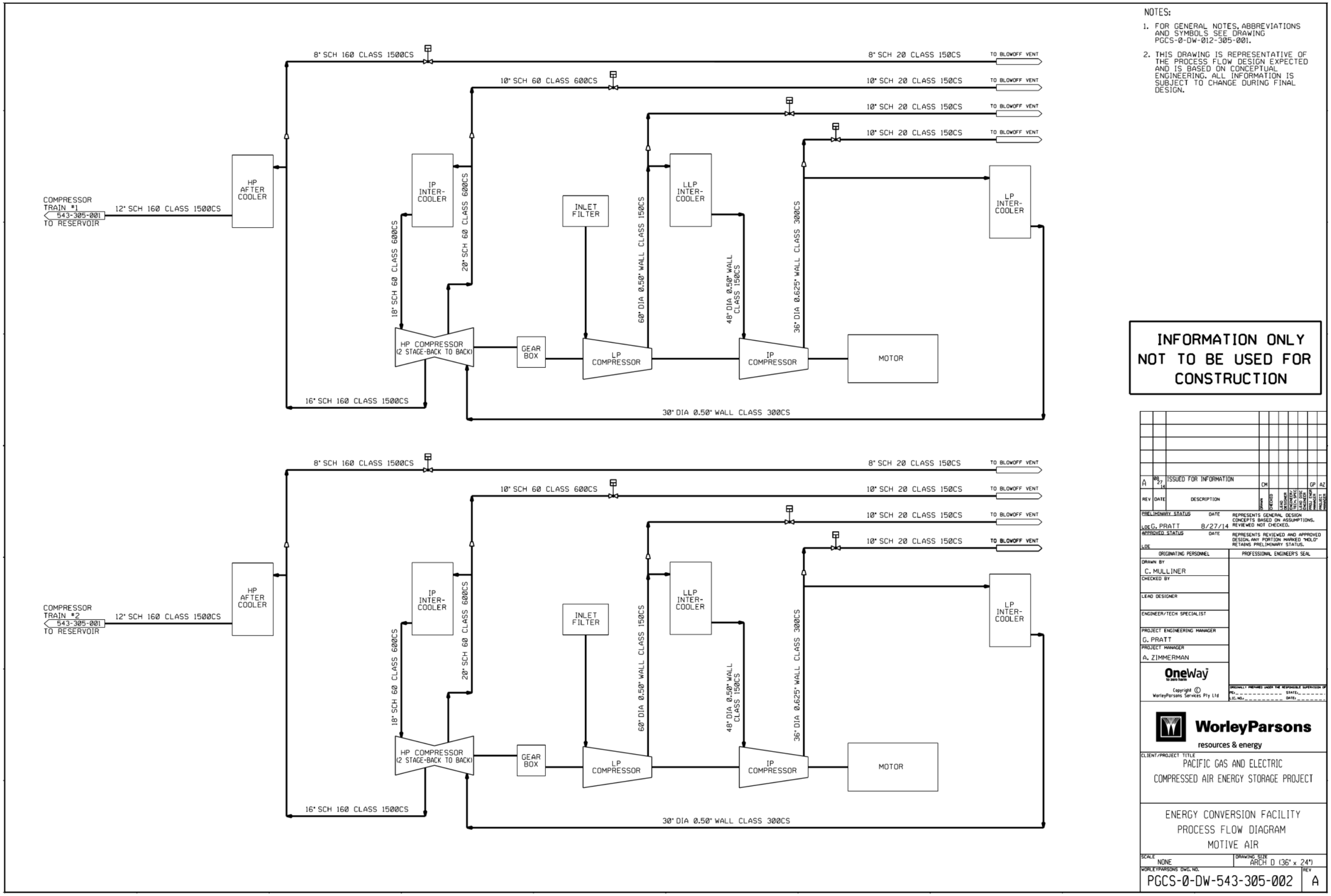


Figure 7-23 Compression Process Flow Diagram

Compression system discharge will create an approximate 500 psig delta over the reservoir pressure; at a minimum, the pressure would be 2340 psig. At this discharge pressure, the storage field is considered to be at its minimum working capacity (1100 MMscfd). The maximum discharge pressure of the compression system will be 2900 psig. At this discharge pressure, the storage field is considered to be at its maximum working capacity. Two compression trains will be in simultaneous operation to achieve the full working mass flowrate of 840 lb/s at the design point ambient conditions of summer season average overnight temperature.

Air compression in each train will occur through polytropic stages. During compression, ambient air will be accepted through the inlet air filter, which will remove contaminants such as dust and moisture. Then the air will be successively compressed through each stage and cooled through shell-and-tube heat exchangers after each stage to remove the heat energy from the air and achieve greater efficiency in the process. After the last high-pressure stage of compression, the air will be cooled through a shell-and-tube aftercooler before entering the air transmission line.

Compression Performance

Compression process flow rates and pressures will be contained via inlet guide vanes (IGV) on the inlet of the low pressure compressor. By adjusting the angle of the IGVs, compressor inlet flow can be modulated within a certain range. The compressor train is designed to operate most efficiently at full flow. At the minimum flow IGV position, inlet flow is approximately 75-80% of maximum flow. Table 7-5 provides a summary of a single train's compression performance, as prepared by Dresser Rand at different ambient and operating conditions. This performance information was used as input to the CAES project Heat and Mass Balance Package (HMB), included in Appendix 7A, Attachment 5, WP Conceptual Design ECF.

Table 7-5 Compression Train Performance Summary (Single Train)

Case	Operating Point Description	Ambient: Dry Bulb Temp [F]	Ambient: Wet Bulb Temp [F]	Ambient: Barometric Pressure [psia]	Ambient: Cooling Water Temp [F]	Delivered at Header: Air Flow [lb/s]	Delivered at Header: Discharge Pressure [psia]	Overall Performance: Power Consumption [kW_e]	Overall Performance: Water Cooling Duty [MMBTU/hr]	Overall Performance: Specific Air Production [lb/kW-hr]
0	Normal Predicted	64.0	56.2	14.696	71	420.8	2,720	137,400	483.0	11.03
1	Normal (Certified)	64.0	56.2	14.696	71	420.4	2,720	137,408	483.0	11.01
2	Typical Winter HP	42.8	41.3	14.696	56	441.5	2,835	141,606	492.6	11.22
3	Typical Winter LP	42.8	41.3	14.696	56	441.7	2,100	136,172	472.7	11.68
4	Typical Summer HP	92.3	67.3	14.696	82	397.5	2,835	133,692	476.1	10.70
5	Typical Summer LP	92.3	67.3	14.696	82	398.1	2,100	127,907	455.1	11.21
6	Normal Low Flow	64.0	56.2	14.696	71	345.2	2,720	112,020	394.2	11.09
7	Normal High Flow	64.0	56.2	14.696	71	447.3	2,719	150,119	526.1	10.73
8	Typical Winter High Flow	42.8	41.3	14.696	56	468.7	2,719	154,350	535.1	10.93
9	Typical Summer High Flow	92.3	67.3	14.696	82	423.2	2,720	144,705	513.7	10.53
10	Extreme Winter HP	16.5	15.5	14.696	40	467.8	2,835	146,677	505.4	11.48
11	Extreme Winter LP	16.5	15.5	14.696	40	467.9	2,100	141,547	486.6	11.90
12	Extreme Summer HP	111.6	79.4	14.696	94	379.6	2,835	130,282	473.0	10.49
13	Extreme Summer LP	111.6	79.4	14.696	94	380.3	2,100	124,623	452.6	10.99

Figure 7-24 is an energy and mass balance for the compression cycle based on both units in operation at full output.

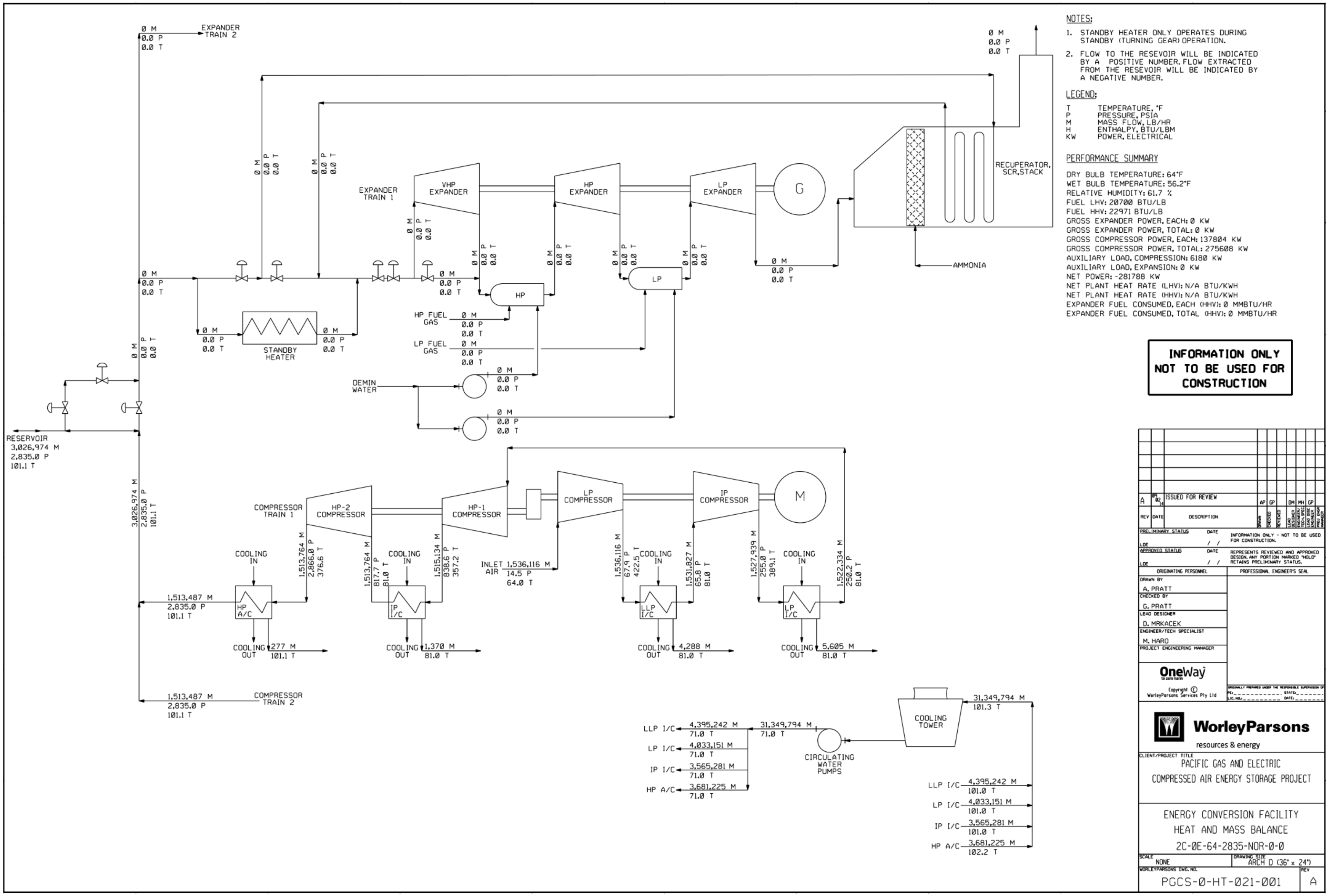


Figure 7-24 Compression Cycle Energy and Mass Balance

Expansion-Generation Process

The expansion-generation process is illustrated in Figure 7-25.

High-pressure air will be withdrawn from the storage reservoir through the air transmission pipeline or will be piped from the compression system via the storage bypass piping. If the system is in rapid startup, the air will pass through an electric heater prior to entering the very-high-pressure (VHP or high-high pressure of HHP) expander. If the system is in normal operations mode, the air will be piped through the waste heat recuperator prior to entering the VHP expander. After being expanded across the VHP turbine (which will perform work on the generator shaft), the lower energy air will enter the high-pressure combustor, where it will be mixed with fuel gas and ignited, providing additional energy to the air, and consequently expanded to a lower pressure in the HP expander. The air will then undergo a similar enthalpy change process through the low-pressure combustor and expander before exhausting into the waste heat recuperator, through the emission control system, and to the atmosphere via the stack.

Similar to a typical gas turbine, the HP and LP expanders will utilize a slipstream of the process air that bypasses the combustors to cool the first turbine blade stages. This cooling system will rely on air film cooling of high-temperature components and will involve small-diameter cooling passages. Therefore, the quality of the stored air will be similar to that needed by a typical gas turbine to provide adequate support for both combustion and turbine blade cooling functions.

At full load, each expander train will operate to provide 158 MW of gross power output on an inlet air flow of 805 pounds per second at 2,128 psia.

Expansion-Generation Performance

Expander performance will be controlled via inlet air flow. Lower inlet flowrates will result in lower electricity generation. Unlike the compression trains, the performance of the expander trains is not sensitive to ambient conditions. Therefore it is not necessary to present expander performance at a number of different ambient conditions because the performance is essentially the same. The expanders can be turned down through decreased flow rates to a minimum gross power output of 45 MW with two turbines. Generation at part load can be achieved if the reservoir storage pressure is reduced, to a minimum pressure of about 800 psia, while meeting emissions compliance. A bypass feature allows the low-pressure air to bypass the VHP expander and be routed directly to the HP expander when operating at lower-than-design air pressure.
A summary of expander performance at various pressures is provided in Table 7-6. This performance information was used as input to the CAES project Heat and Mass Balance Package included in Appendix 2 of the WorleyParsons Conceptual Design and Cost Estimate Report (see Appendix 7A, Attachment 5, WP Conceptual Design ECF).

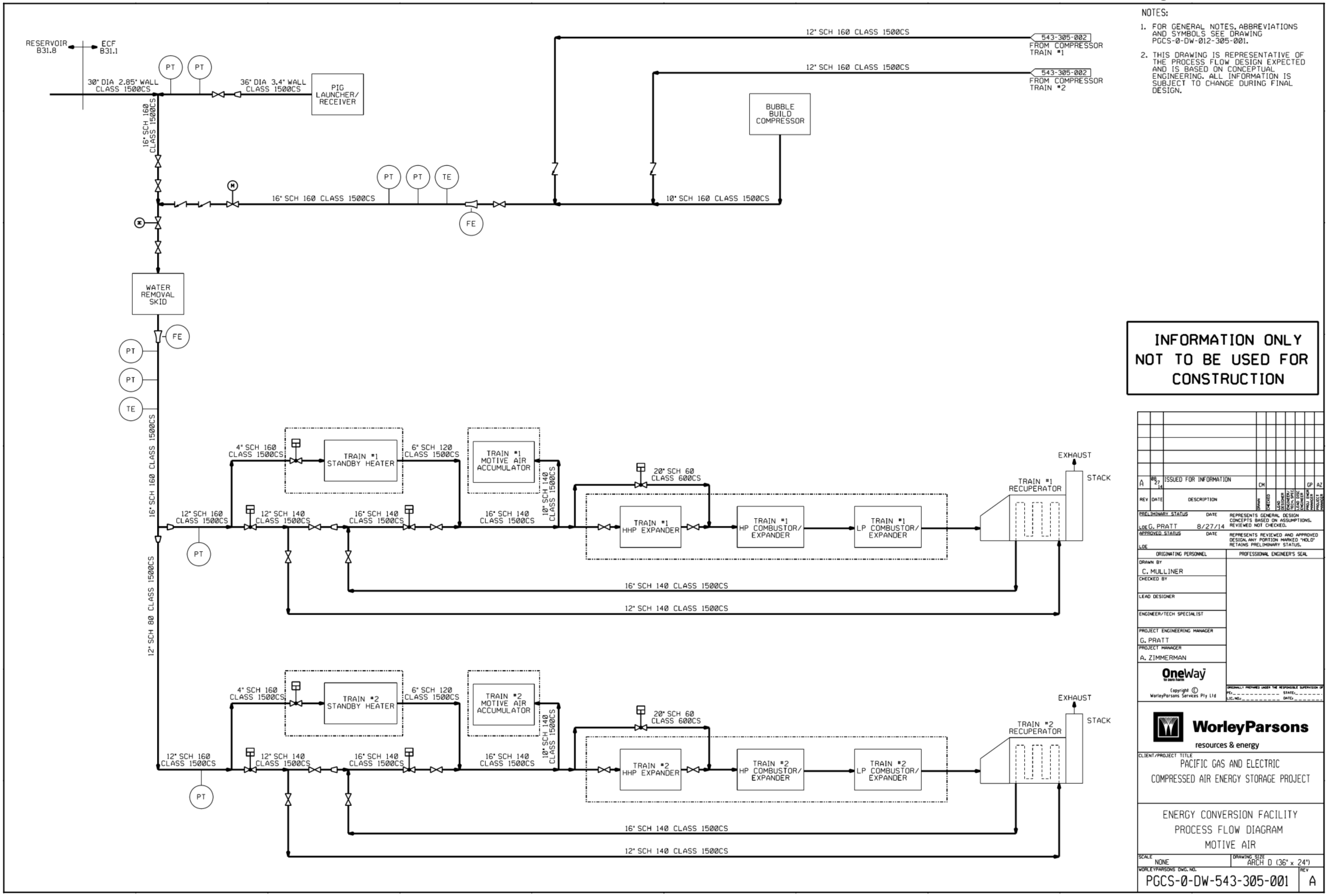


Figure 7-25 Expansion-Generation Process Flow Diagram

Table 7-6 Summary Expander Performance (per train)

Case Type Identifier	Minimum Recup. Inlet PSIA	System Flow lb/sec	Bypass Flow lb/sec	Generator Train Power	SAC lbm/kWhr	HR (LHV) BTU/kWhr	HR (HHV) BTU/kWhr	SFC lbm/kWhr	Total Fuel lbm/sec	Demin H_2O lbm/sec	Exhaust Flow Rate lbm/sec
HSL (Certified)	2128	402.7	0.00	158,008	9.175	3887.9	4313.4	0.1924	8.444	3.377	414.58
Part Load - 86%	1874	352.3	0.00	136,163	9.316	3938.7	4369.8	0.1949	7.371	2.949	362.52
Part Load - 72%	1630	302.0	0.00	113,920	9.543	3995.7	4433.1	0.1977	6.256	2.503	310.54
Part Load - 57%	1375	251.6	0.00	89,899	10.077	4067.5	4512.7	0.2013	5.026	2.010	258.51
Part Load - 42%	1099	201.3	0.00	65,595	11.049	4149.2	4603.4	0.2053	3.741	1.496	206.42
Part Load - 25%	794	146.0	0.00	39,784	13.208	4303.1	4774.2	0.2129	2.353	0.941	149.17
Part Load - 25%-Water Inj Off	792	146.0	0.00	39,319	13.365	4213.6	4674.9	0.2085	2.277	0.000	148.18
Part Load - 11%-Water Inj Off	480	88.6	0.00	18,063	17.662	4772.8	5295.3	0.2362	1.185	0.000	89.78

Notes: 1. Gas LHV=20209.9 BTU/lbm & HHV=22422.2 BTU/lbm from REFPROP for Energy Transfer gas sample data.
2. Performance in table is based on elevation of 0 ft/14.696 PSIA barometric pressure.
3. Fuel gas temperature = 100F at fuel nozzles for all cases.
4. Demin H2O temperature = 68F at fuel nozzles for all cases where water injection is enabled.
5. Inlet air temperature = 112F at recuperator inlet for all cases.

Figure 7-26 is a heat and mass balance for the expansion/generation cycle based on both units in operation at full output.

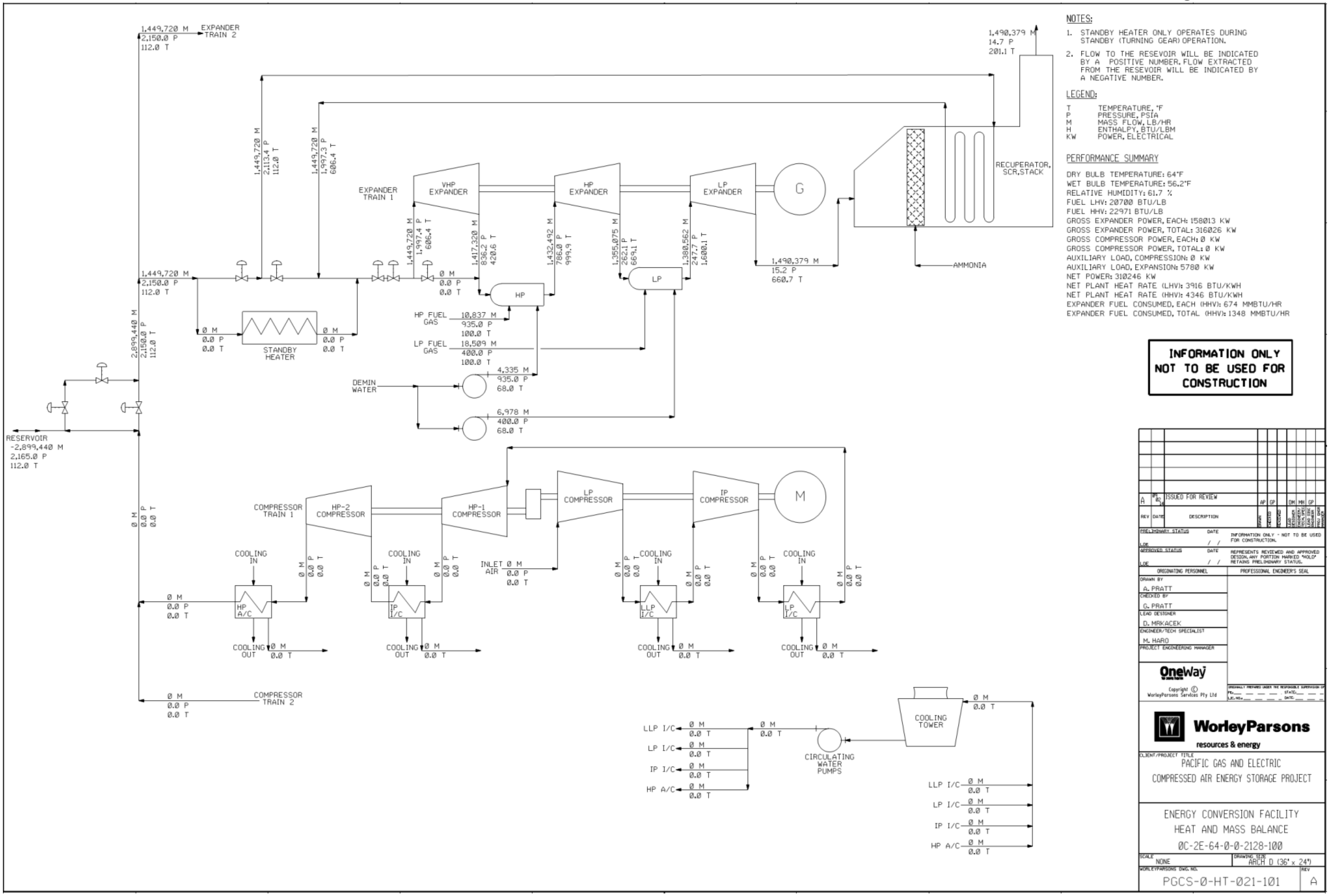


Figure 7-26 CAES Plant Heat and Mass Balance for Two Units at 100% Output

7.6 SMARTCAES™ DESIGN WITH 6-HOUR RE-INJECTION SUMMARY

The SMARTCAES™ technology offers many benefits well suited for meeting the operational challenges associated with increasing volumes of intermittent renewable resources and changing grid conditions.

1. The expanders-generators can be started and achieve full load within approximately 10 minutes from a start signal.
2. The expansion/compression cycles are capable of responding to load changes rapidly and could support operations for grid ancillary services.
3. Superior performance is possible at multiple load conditions while remaining within environmental compliance. Performance is not significantly affected by ambient temperature and/or relative humidity.
4. Faster compression times can be achieved to reduce the amount of time required to charge the reservoir; this capability allows the CAES operator to take advantage of shorter periods of low prices and allows for more hours available for generation.
5. As designed, simultaneous generation and compression can allow the facility to provide more services to the grid operator and respond more rapidly to changing grid conditions and prices.
6. When not in a simultaneous mode of operation, the compression trains can start and be in full operation in 10 minutes. This capability allows short-term cost-saving opportunities when electric prices fall to very low levels, providing an opportunity to run the compressors at a very low operating cost to re-supply the air reservoir.
7. The compressors can be decoupled from the electric drive motors so that the motors can operate as synchronous condensers for providing volt-ampere reactive (VAR) support to the transmission system during any hour in which compression operations are not needed. Since these are large motors, they would be capable of providing significant support of both leading and lagging power factors. The use of the variable-frequency drive (VFD)-type Load Commutated Inverter (LCI) will allow the motors to be started quickly if a need arises to operate in synchronous condenser mode.
8. The turbine-generators can provide limited VAR support during operation.

7.7 CAPITAL COST SUMMARY

The cost estimate for the reservoir and air transmission system conceptual design was delineated into two categories:

1. **Air Transmission System,** including the air pipeline, two wellhead pads, and supports and piping for the various wells.
2. **Wells,** including the various air injection/withdrawal wells, water production wells, water injection wells, and the conversion of existing wells for observation purposes.

7.7.1 Air Transmission System

As the Project Consulting Engineer (PCE), WorleyParsons developed a Class-1 quality cost estimate for the installation of the well pad facilities (excluding the construction of the various injection/withdrawal wells) and the air transmission pipeline. Also included is a Class-1 quality cost estimate for the water pipeline previously discussed. The cost estimate for the identified project scope is expected to have an accuracy within the range of -20% to +40%.

Appendix 5 of the WorleyParsons Air Transmission System Conceptual Design and Cost Estimate includes various components of the cost estimate, including various assumptions, inclusions/exclusions, estimates of both direct and indirect costs (2014 dollars), as well as escalation and contingency assumptions. Because the exact timing of construction of the project is unknown at this point, the escalation values estimated in the report were eliminated; the estimated costs were then re-calculated by applying the category contingency factors to the various costs absent the escalation amount. Tables 7-7 through 7-10 summarize the various estimates.

Table 7-7 Summary of Air Pipeline Costs

Air Transmission Pipeline – 30 inch, 3,000 psi (Maximum Allowable Operating Pressure [MAOP])	
Description	**Costs (000s)**
Construction	$4,677
Materials	$10,653
Indirect Costs	$4,622
Contingency	$2,993
TOTAL	$22,945
Accuracy Range (-20% to 40%)	$18,356 - $32,123

Table 7-8 Summary of Well Pad Development Costs

East and West Well Pad Sites	
Description	**Costs (000s)**
Equipment	$6,487
Commodities	$10,089
Indirect Construction	$2,789
Eng. & Third Party	$5,186
Contingency	$4,910
TOTAL	$29,461
Accuracy Range (-20% to 40%)	$23,568 - $41,245

Table 7-9 Summary of Produced Water Pipeline (ECF to Well Pad Site)

Water Pipeline – 4 inches	
Description	**Costs (000s)**
Construction	$1,123
Material	$310
Indirect	$773
Contingency	$331
TOTAL	$2,537
Accuracy Range (-20% to 40%)	$2,030 - $3,160

Table 7-10 Summary of Air Injection/Withdrawal (I/W) Well Costs

Directional Injection/Withdrawal Well – 4,770 foot Depth	
Description	**Cost/Well (000s)**
Lease and Well Equipment: Drilling	$447
Lease and Well Equipment: Completion	$730
Intangibles: Drilling	$1,204
Intangibles: Completion	$258
TOTAL	$2,639

The water withdrawal wells are expected to have a similar cost/well as the air I/W wells ($2,639,000). The water disposal wells, which would be drilled and completed to a depth significantly below the air I/W wells, were estimated to cost 1.25x the amount of an air I/W well.

The cost to convert existing wells to observation wells, based upon work performed as part of the air injection test, was estimated to cost $125k/well.

Table 7-11 summarizes the well cost estimate; Table 7-12 summarizes the estimated costs for the well pad development, costs for the development of the various wells, and the air transmission development cost.

Table 7-11 Summary of All Well Development Costs

Description	# of Wells	Unit Cost (000s)	Total Cost
Air Injection/Withdrawal	30	$32,693	$79,170
Water Production	4	$2,639	$10,556
Water Injection	2	$3,299	$6,598
Observation	2	Varies	$250
TOTAL			$96,574
Accuracy Range (-20% to 40%)			

Table 7-12 Summary of Reservoir and Air Transmission Development Costs

Description	Cost (000s)
Air Transmission Pipeline	$22,945
Wellpads	$29,461
Water Pipeline	$2,537
Wells (various)	$96,574
TOTAL	$151,517
Accuracy Range (-20% to 40%)	

7.7.2 ECF

As the PCE, WorleyParsons developed a Class-2 quality cost estimate, based on the conceptual design, for the construction and installation of the ECF. The estimate was prepared in part by utilizing the AspenTech "In-Plant" cost-estimating software, along with vendor pricing and historical cost data on selected materials. Vendor quotes were obtained for the major equipment and other main components. The majority of all bulk commodity pricing is based on the In-Plant software, including piping, electrical, instruments, and civil costs. The cost estimate for the identified project scope is expected to have an accuracy within the range of -20% to +25%.

Section 16 and Appendix 7 of the WorleyParsons Conceptual Design and Cost Estimate Report include various components of the cost estimate, including various assumptions, inclusions/exclusions, a cost estimate (2014 dollars), and escalation and contingency assumptions. Because the exact timing of construction of the project is unknown at this, the escalation values estimated in the report were eliminated; the estimated costs were then re-calculated by applying the contingency factor to the various costs absent the escalation amount. Table 7-13 summarizes the ECF cost estimate.

Table 7-13 Summary of ECF Costs

Description	**Cost (000s)**
Procurement Packages	$246,455
Construction Packages	$166,080
Engineering, Const. Mgmt, & Start-Up	$25,000
Other	$8,766
Contingency	$55,788
TOTAL	$502,089
Accuracy Range (-20% to 25%)	$401,671 - $627,611

Section 16 and Appendix 12 of the *WorleyParsons Conceptual Design and Cost Estimate Report* provide more discussion of this topic. (See “PG&E ECF Conceptual Design Report PGCS-O-LI-O12-0003 Rev C Final.pdf” in Appendix 7A_Attachment 6_CAES Final Tech Memo FINAL 25 Sept 2015 Rev 0 Full.)

7.7.3 Electric and Natural Gas Transmission Interconnect Costs

Electric and natural gas interconnection costs for the selected site would be provided, via formal processes, conducted, respectively, by the California Independent System Operator (CAISO) and Pacific Gas and Electric Company (in its role as the gas transmission/distribution service provider).

Because the project is still in the conceptual stage and the ultimate developer/operator may make changes to the conceptual design discussed herein, PG&E sought out preliminary estimates of these costs and the required work based upon the conceptual engineering. The following information is preliminary, and the actual costs/scope of work would only be determined by participating in the formal interconnection processes managed by each of these organizations. However, the studies summarized herein provide an exploratory assessment of each system to support the increased load, identify the work (if any) that would need to be conducted to support the increased load, and provide a rough estimate of the associated costs.

Electric Interconnection

PG&E contracted with Flynn Resource Consultants Inc. to provide an independent assessment of interconnecting the ECF. The objective of this transmission screening study (Flynn RCI 3-PG&E 300 MW Compress Air Energy Storage Transmission Interconnection Screening Study Report, October 21, 2014) (see Appendix 7A, Attachment 1, PGE CAES Electrical Interconnect Study Report—Revised Final 141021.pdf) was to determine the ability of the transmission system to support the operation of the ECF. The generation mode was modeled as 330 MW of injection (slightly higher than the net output determined in the WorleyParsons Conceptual Design and Cost Estimate Report 13-Mar-15) (see Appendix 7A, Attachment 5, WP Conceptual Design ECF) into the CAISO grid; the compression mode was modeled as a 150 MW withdrawal, with sensitivity of up to 275 MW (this was done to determine any impacts from utilizing a shorter injection rate than the 6-hour previously discussed).

Upgrades to the electric transmission system are categorized as either Direct Assignment or Reliability Network Upgrades (RNU). The developer is responsible for and pays all of the Direct Assignment costs. However, those costs identified as Reliability Network Upgrades are associated with upgrades that will benefit the system and not just the project. Therefore, those costs categorized as Reliability Network Upgrades are reimbursed with interest by the transmission owner over a period of five years once the facility is operational; the interest rate is outlined by the Federal Energy Regulatory Commission (FERC).

The screening study identified the costs (2013 dollars) shown in Table 7-14.

Table 7-14 Electrical Interconnection Costs

Element	**Cost (2013 Dollars)**	**Comment**
Typical 230-kV Interconnection Facility Cost	$2,000,000	Not reimburseable
Single Loop 230-kV Interconnection Station	$18,100,000	Reimburseable
Reconductor ECF-Eight Mile 230 kV (2.7 miles)	$7,000,000	Reimburseable
Special Protection Scheme	$700,000	Not reimburseable
Total Costs	$27,800,000	

Natural Gas Interconnection

PG&E's Pipeline Services Group was requested to perform a study to determine the best route to provide natural gas service to the proposed ECF. Various routes and alternatives were studied. Balancing costs, minimization of pipe footage installed, and maintaining service pressures to other customers in the vicinity, the alternative selected results in a delivery pressure of 248 psig to the ECF site and approximately 8,360 feet of 12-inch pipe installed at a cost of $14.35 MM (preliminary estimates such as this are categorized as +/- 50%).

7.7.4 CAES Engineering, Procurement and Construction (EPC) Cost Estimate

Table 7-15 summarizes the various cost components reviewed within this chapter.

Table 7-15 CAES EPC Costs

Description	**Cost (000s)**
Air Transmission and Reservoir Cost (Table 7-12)	$175,360
ECF (Table 7-13)	$502,089
Electric Interconnection	$27,800
Gas Interconnection	$14,350
TOTAL	$719,599

Appendices

Appendix 7A, Attachment 1, Electric Transmission
Appendix 7A, Attachment 2, WP Conceptual Design Addendum Alt ATS
Appendix 7A, Attachment 3, WP Conceptual Design Addendum Alt ECF Site
Appendix 7A, Attachment 4, WP Conceptual Design ATS
Appendix 7A, Attachment 5, WP Conceptual Design ECF
Appendix 7A, Attachment 6, CAES Final Tech Memo FINAL 25 Sept 2015 Rev 0 Full
Appendix 7A, Attachment 7, King Island Progress Report 01-29-2014 FullField.pdf
Appendix 7A, Attachment 8, King Island Progress Report 09-03-2014 FullField Case 3B1.pdf
Appendix 7A, Attachment 9, King Island Progress Report 09-10-2014 FullField Case 4B1.pdf

Chapter 8
Environmental Siting, Licensing, and Permitting Analysis

8.1 INTRODUCTION

This chapter provides a summary of the environmental and general permitting considerations associated with building a full-scale, CAES facility at the proposed King Island site.

As outlined in prior chapters in this report, PG&E undertook and completed earlier phases of the overall CAES project, including project feasibility, site/reservoir screening, site control, testing, preliminary engineering, and related project development activities. These efforts ultimately resulted in completion of a preliminary design and the acquisition of various land rights for a commercial-scale CAES project sited at King Island, near Stockton, California. Many of the permitting activities for the King Island CAES Project (KICP) benefited from the extensive analysis and permitting work completed during these prior phases. A significant amount of knowledge was developed from these activities, including environmental field studies, cultural studies, and agency-approved Avoidance and Minimization Measures (AMMs). The scope of these prior phases included three fundamental work activities based on the location selected: (a) core well construction (see Chapter 5), (b) construction of the electric distribution line to the Temporary Site Facility (TSF) site to power the electric compressor motors during the Air Injection Test phase, and (c) construction of the TSF on King Island and subsequent compression testing of the gas field. In particular, the latter involved preparation and approval of an Environmental Assessment (EA) and Finding of No Significant Impact (FONSI) provided by the Department of Energy (DOE) to demonstrate compliance with the National Environmental Policy Act (NEPA), as discussed in more detail in Chapter 5.

Assuming a potential commercial-scale project, the Environmental Siting, Licensing, and Permitting Analysis (ESLPA) (KICP_ESLPA_FINAL-Volume_1-Document.pdf and KICP_ESLPA_FINAL-Volume_2-Appendixes.pdf) Appendix 8A, Attachment 7, ESLPA Final Volume 1 Document.pdf; and Appendix 8A, Attachment 8, ESLPA Final Volume 2 Appendices.pdf) for the KICP is based on the preliminary KICP design, various land rights under site control, and other boundary conditions. A fundamental requirement is the ability for the KICP to store and generate approximately 3000 MWH of power. The high-level project scope consists of the Energy Conversion Facility (ECF), reservoir/well-field, and various linear facilities, which are more fully described in Chapter 7 and summarized below. The ESLPA also includes an Underground Injection Control Permitting Analysis (UICPA), which reviews and summarizes the separate EPA permitting requirement for the reservoir and associated wells.

Note: As described in Chapter 7, an alternate ECF site was also investigated; as a companion to the WorleyParsons Conceptual Design and Cost Estimate Report Addendum 1 for Alternate Ming Centre Site, (see Appendix 8A, Attachment 3, Finding of No Significant Impact.pdf)
PG&E tasked CH2MHill with investigating the key environmental and permitting differences between siting the ECF at the Ming Centre site vs. the original site investigated in the ESLPA. The results of this study are provided in the Environmental Siting, Licensing and Permitting Analysis Supplement – Ming Centre Alternative Site. Chapter 8 focuses on the environmental and general permitting considerations if the project design results in the ECF being located at the

originally located site. The permitting effort for the KICP can be broken down into two distinct processes: surface facilities and reservoir.

8.1.1 Surface Facilities

This portion of the ESLPA focuses on the environmental impacts associated with the construction and operation of the ECF, well field surface facilities, roads/logistics, and all associated linear facilities. Although the majority of the linear piping facilities would be buried, for purposes of this report they are described within the "surface" category rather than the more specialized reservoir category. As it relates to construction and operation, the majority of the impacts are related to the ECF but also take into account potential impacts related to the installation and operation of the various wells and related facilities located above the reservoir.

8.1.2 Reservoir

This portion of the ESLPA addresses the same environmental impacts as those outlined above. However, this section also includes special permitting requirements unique to the Injection/Withdrawal wells and related gathering system, as well as the wastewater disposal wells/system. Hence, primarily this section focuses on the Environmental Protection Agency (EPA) process/requirements (UICPA) applicable to injection of fluids into underground porous rock formations for storage or disposal, including a focus on the geology, Area of Review (AOR), and the associated full field development modeling results, potential corrective action plan issues, etc. In addition, permitting considerations dictated by the California Department of Geothermal and Gas Resources (DOGGR) are discussed.

The structure of this analysis is predicated on a "base case" preliminary project design and siting assumptions (see the Worley Parsons Conceptual Design and Cost Estimate Report [Appendix 8A, Attachment 5, KICP Appendix 5.3F CompTest 05.31.2013.pdf] as well as the ESLPA [Appendix 8A, Attachment 7, ESLPA Final Volume 1 Document.pdf; Appendix 8A, Attachment 8, ESLPA Final Volume 2 Appendices.pdf] for a definition of the base case/key assumptions), which have been developed during the CAES feasibility study for the commercial-scale facility. In addition, various siting and facility design alternatives are presented and discussed. For example, Chapter 3, "Reservoir Screening and Site Identification," presents the process and factors considered to screen 148 potential reservoirs down to the two chosen for core drilling and ultimately the site associated with the KICP. Chapter 7, "CAES Plant and Reservoir Design," presents various facility alternatives reviewed (for example, wet vs. dry cooling).

Chapter 8 first provides a high-level project description including a review of the surface and reservoir facilities. It then follows the ELSPA structure and discusses the 16 sociological and environmental disciplines that are covered in a standard Application for Certification (AFC) filing to the California Energy Commission (CEC) to license a thermal power plant with a nominal generating capacity of more than 50 MW.

8.2 PROJECT DESCRIPTION

Other than the Injection/Withdrawal (I/W) well, well pad, and associated residual facilities from the testing phase, KICP would essentially be developed as a "green-field" project. Figure 8-1 is a site layout/location drawing. Figures 8-2 and 8-3 provide a view of the proposed ECF site and one of the well pad sites when photographed in 2014.

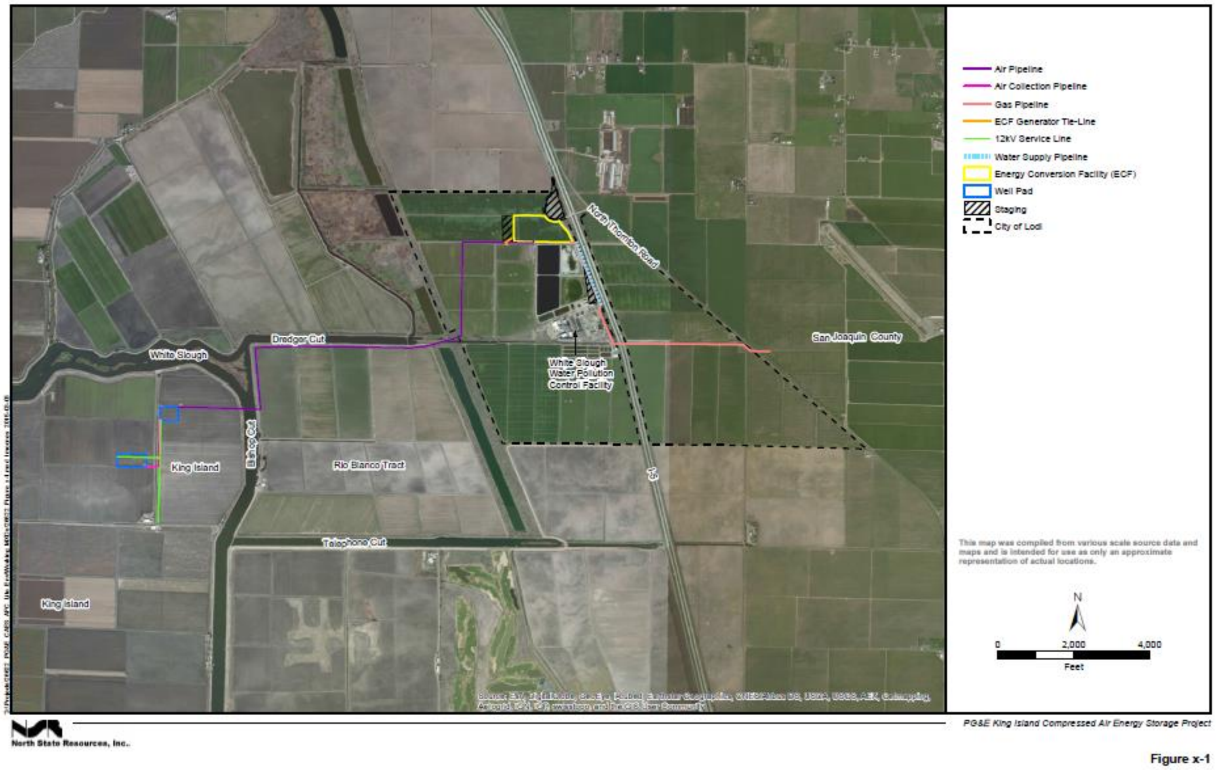


Figure 8-1: Site Layout/Location Drawing

Figure 8-2: View from Northwest of ECF Site

Figure 8-3: View to the South of One of Wellfield Sites Located at Intersection of Power Lines

A detailed technical project/process description of the ECF has been provided (see the Worley Parsons Conceptual Design and Cost Estimate Report [Appendix 8A, Attachment 5, KICP Appendix 5.3F CompTest 05.31.2013.pdf] as well as the ESLPA [Appendix 8A, Attachment 7, ESLPA Final Volume 1 Document.pdf; Appendix 8A, Attachment 8, ESLPA Final Volume 2 Appendices.pdf] for a definition of the base case/key assumptions). As indicated in the Introduction above, the project description is based on various siting and design assumptions associated with the project configuration developed as part of the CAES feasibility study (base case). Thus, the following is intended as a high-level summary of the principal base case design features relevant to the KICP permitting process.

8.2.1 Reservoir and Well Field

- **Reservoir:** The heart of the KICP is the King Island natural gas field, which would be developed to store compressed air for subsequent release and conversion to electric power. Compressed air from the ECF would be conveyed through a pipeline to a series of I/W wells and injected into the reservoir. The reservoir is an underground geological structure located approximately 4,700 feet below the surface of King Island, approximately 2.5 miles southwest of the ECF site. The reservoir is a nearly depleted natural gas field that has been used for gas production from 1985 to the present. All gas production from this field would have ceased prior to KICP commissioning, making the structure available for CAES.
- **Injection/Withdrawal (I/W) Wells:** Under base case assumptions, there would be 25-30 air I/W wells located on two well pads (see below).
- **Water Removal:** The process of building the initial air bubble is expected to require the physical removal of formation water from the reservoir. The withdrawn water would be re-

injected into EPA-permitted injection wells completed to zones deeper than potable underground sources of drinking water (USDW) and the air storage reservoir. In the vicinity of King Island, the Starkey formation is deeper than the USDW and would not interfere with the air storage operations in the Mokelumne River formation. In addition to the need to dispose of water withdrawn from the storage reservoir during the bubble build period, it will be necessary to dispose of water produced during normal operations. An estimated 5,000 Bbl/day of water could be produced and separated from the air flow stream during normal withdrawal operations, but could be 2.5 times higher during the initial bubble build period. Along with any ECF wastewater, this produced water would be disposed of in the wastewater injection wells as described above and in greater detail in the UICPA.

- **Ancillary Equipment:** Injection and withdrawal (I/W) equipment and controls will be sited at the two well pads, as described below, to manage the I/W functions, potential production of residual natural gas return from the I/W wells, produced water, and various other operational functions.

8.2.2 Surface Facilities

- **ECF:** The core of the ECF is the power island, consisting of the air compressors, turbo-expander generators, and associated ancillary equipment. In addition, the ECF includes natural gas compressors, a switchyard, cooling towers, and a host of other equipment located on a site of roughly 20 acres. As designed in conjunction with the CAES feasibility study for the compressed air storage phase of operation, the KICP would use two Dresser-Rand CAES compression trains. Each train consists of a multi-stage compressor section driven by a dedicated 137 MW (nominal rating) electric motor. Each compression train would be capable of producing approximately 400 pounds per second of air at a compressor outlet pressure of up to 2,720 psia.
- **Well Pads:** These facilities consist of the air I/W wells, a wastewater injection well(s), and ancillary equipment. Under base case assumptions, the west well pad would be six acres in size, and have 20-25 air I/W wells, two water withdrawal wells, and up to one wastewater injection well. The east well pad would be four acres in size, and have 5-10 air I/W wells, two water withdrawal wells and one water injection well. Ancillary Equipment would include hydrocarbon monitoring/control equipment, a control building, a water storage tank with properly sized pumps, and the interconnecting (primarily underground) piping between the equipment location and the disposal well site at each well pad.
- **Air Collection Pipeline:** Air collection pipeline (east well pad to west well pad, primarily underground).
- **Natural Gas Pipeline:** Natural gas pipeline (1.5 miles) to convey fuel to the ECF from PG&E distribution feeder main (DFM). Development efforts to date were based on the assumption that the gas distribution utility would be responsible for design and installation of this pipeline up to the ECF site boundary.
- **Recycled Cooling Water:** Recycled cooling water supply pipeline from the City of Lodi's Water Pollution Control Facility (WPCF) (roughly 1/4 mile).
- **Air Pipeline:** A 30-inch-outside-diameter bi-directional pipeline would be constructed to convey compressed air from the ECF compressors to the well field/reservoir and back from the well field to the ECF. The air pipeline design would include blow-down valves, condensate traps/drains to manage water dropout, and pipeline "pigging" equipment for maintenance.

- **Major Electrical Equipment and Systems:** The bulk of the electric power produced at the ECF switchyard would be transmitted to the electrical grid through a 300-foot-long 230-kV connection to PG&E's 230-kV Gold Hill-Eight Mile Road transmission line. Electric power would be used onsite mainly to drive the compressors, but also for minor uses to power auxiliaries such as pumps and fans, control systems, and general facility loads including lighting, heating, and air conditioning.

8.3 ENVIRONMENTAL CONSIDERATIONS

As discussed above, this chapter summarizes the results of a detailed ESLPA, considering 16 areas of possible environmental effects of the project, pursuant to the requirements set forth in existing environmental laws and the CEC's regulations. Detailed descriptions and analyses of these areas are included in the ESLPA report. In addition, considerations unique to the reservoir permitting process are discussed. The ESLPA highlights the most important environmental licensing and permitting issues, by discipline, that have been identified during an environmental effects analysis of the project.

1. Air Quality

The KICP project is located in the San Joaquin Valley Air Basin (SJVAB), for which the air quality permitting authority is the San Joaquin Valley Air Pollution Control District (SJVAPCD). The SJVAB is in attainment of the National Ambient Air Quality Standards, except for 8-hour ozone (extreme) and annual and 24-hour Particulate Matter standards (PM_{10}) (moderate). The basin is in attainment of the California Ambient Air Quality Standards, except for 1-hour and 8-hour ozone, annual and 24-hour PM_{10}, and annual $PM_{2.5}$.

The KICP would be required to apply for an Authority to Construct (ATC) permit in accordance with SJVAPCD Rule 2010. A complete application for an ATC would be filed with the SJVAPCD prior to submittal of the complete AFC to the CEC. The permit application would include meteorological modeling of emissions from the proposed KICP using meteorological data from existing monitoring stations. Suitable data for most of the criteria pollutants is available for the KICP's location from existing, nearby monitoring stations.

Criteria pollutant and greenhouse gas (GHG) emission rates were calculated for the operational phase of the project, evaluating ECF performance at assumed base case conditions. Potential To Emit (PTE) maximum annual emissions of volatile organic compound (VOC), nitrogen oxide (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), PM_{10}, and $PM_{2.5}$ were estimated, based on expected operations (excluding startups, shutdowns, and commissioning) and assuming an operation schedule of 5 days per week, 10 hours per day.

The emissions analysis showed that the KICP would be required to provide emission offsets for NO_x emissions, based on its projected annual emissions of 12 tons per year (tpy), compared with the offset threshold of 10 tpy. Currently the SJVAPCD's offset bank appears to hold sufficient credits for NOx and other pollutants for future growth with current pricing in the range of $40,000 to $50,000 per ton (refer to Chapter 4.1 in the ESLPA). For Clean Air Act permitting, offsets would not be required for other pollutants. (Note: The quantity of offsets required is likely to change based on the addition of KICP startup, shutdown, and commissioning emissions estimates or should a different operating profile be analyzed. Therefore, a full offsets analysis would be required during the CEC licensing process.).

Greenhouse gas (GHG) emissions for normal facility operations were calculated based on the maximum fuel use predicted for the KICP. GHG emissions would be required to be offset at the state level through the California Air Resources Board's (CARB's) GHG auction mechanism.

Based on the SJVAPCD's rules, a Best Available Control Technology (BACT) analysis is required for the uncontrolled emissions of NO_x, VOC, CO, SO_2, PM_{10}, and $PM_{2.5}$. The proposed BACTs for these pollutants are expected to be as follows and as more fully described in Chapter 4.1 of the ESLPA:

- NO_x – Use of water injected-low NO_x combustors with selective catalytic reduction (SCR)
- CO – Best combustion design and the installation of an oxidation catalyst system
- VOC – Best combustion design and the installation of an oxidation catalyst system
- PM – Best combustion practice, use of pipeline-quality natural gas, and use of inlet air filtration to control PM_{10}/$PM_{2.5}$ emissions
- SO_2 – Exclusive use of pipeline-quality natural gas with a fuel sulfur content of less than 0.75 grain per 100 scf

It is expected that the KICP emissions would not interfere with the attainment or maintenance of the applicable air quality standards; however, this would need to be confirmed through modeling performed as part of the licensing process. Because the SJVAB is currently a non-attainment area for state PM_{10} and state and federal $PM_{2.5}$ ambient air quality standards, any increase in PM_{10} or $PM_{2.5}$ emissions has the potential to exacerbate existing violations. The project owner would provide PM_{10} and $PM_{2.5}$ offsets to mitigate the impact of the emissions increase. Based on the expected project emissions and the ERC requirements of the SJVAPCD, it is expected that the project ERC cost would be in the range of \$30,000 to \$120,000 at current market prices (refer to Chapter 5.1 of the ESLPA for a detailed analysis).

2. Biological Resources

The project area is located within the "Delta Islands," subarea of the Sacramento-San Joaquin Delta area. These are areas of former marshlands of the Sacramento–San Joaquin Delta that were historically reclaimed for agricultural use by the construction of levees/dikes and draining. The majority of the land is in agricultural production. Land not in active cultivation is used for irrigated pasture for livestock production. Vegetation communities within the project area include annual grassland, fresh emergent wetland, orchard/vineyard, open water, ruderal, and valley foothill riparian.

Field Surveys

Biological field surveys to identify sensitive biological resources within the KICP project area focused on potential special-status plant and animal species and their habitats. Field survey areas are depicted in Figure 8-4. Evidence of sensitive wildlife species observed during the surveys included: cliff swallow, Swainson's hawk (nests), and western pond turtle.

Figure 8-4: KICP Field Survey Area

Botanical surveys of the project area were conducted during the spring of 2014 during the appropriate blooming period for special-status plant species with potential to occur in the project area. Botanical surveys did not detect any special-status plant species, and these species are not expected to occur within the project area.

A reconnaissance-level survey for potential waters of the United States within the project area was also conducted. Potential waters of the United States occur as irrigation canal, open water, riparian wetland, vegetated ditch, wetland swale, and non-vegetated ditch.

Special-Status Species

Twenty-one special-status wildlife species have the potential to occur in the project area as summarized as follows:

Fish—Most of the nine special-status fish species present near KICP would not be affected by day-to-day operation of the project but could be affected by construction activities that involve horizontal directional drilling (HDD) under major water bodies such as Bishop Cut and White Slough and therefore raise the possibility of leakage of harmful chemicals into the water body during drilling. This potential for impacts on special-status fish would be temporary and would only be a threat during drilling activities under the water bodies. Implementation of avoidance and minimization measures including development of a HDD Fluid Release Contingency Plan would mitigate these potential effects. No operational impacts are anticipated.

Reptiles—Project construction and operation activities have some potential to adversely affect the federal- and state-threatened giant garter snake (GGS, *Thamnophis gigas*). The potential for impact is also seasonal and depends on the giant garter snake activity period in which the work would be conducted. During the inactive period, GGS seek refuge in upland cover generally within 200 feet of aquatic habitat. Fresh emergent wetlands associated with the White Slough Wildlife Area and irrigation ditches and canals present throughout the project area generally provide low- to moderate-quality habitat for GGS. Impacts from construction activities in proximity to GGS aquatic habitat are anticipated to occur over one construction season, less than one year. Potential construction impacts on this species could be avoided by adopting AMMs that involve fencing of sensitive areas, seasonal avoidance measures, and monitoring. No operational impacts are anticipated. A significant body of knowledge on local GGS habitat and acceptability of AMMs to the relevant agencies was acquired during the core drilling and Air Injection Tests (AIT) phases of the project (see earlier chapters).

Amphibians—Project construction and operation activities have the potential to affect the western pond turtle (*Emys marmorata*), a state species of concern. Western pond turtles have been observed in White Slough and near the ECF site. White Slough, Bishop Cut, wetted irrigation ditches, and canals provide aquatic habitat. Uplands adjacent to aquatic habitat provide upland nesting habitat. During field surveys, western pond turtles were observed in White Slough outside the northwest portion of the project area and in an irrigation ditch on the east side of the project area. Potential impacts to this species could be avoided by adopting avoidance and monitoring mitigation measures.

Birds—Five special-status avian species have a moderate to high likelihood to occur in the project area. Swainson's hawk nesting and foraging habitat is present within and adjacent to the project area. Isolated trees may provide nesting habitat, and agricultural land cultivated in annual or perennial low-growing crops provides foraging habitat. Two potential nests were observed during the reconnaissance surveys relatively near project facilities, and a nesting pair was observed near King Island during the compression testing phase. Noise generated during construction could affect Swainson's hawks if active nests are located within 0.25 mile of the survey area. The project would convert farmland (i.e., that provides foraging habitat) to industrial use, which would result in the permanent loss of approximately 20 acres of crop land foraging habitat at the ECF site. Regulatory agencies would require compensation for the foraging habitat. Measures to avoid impacts on Swainson's hawks include removal of vegetation outside the nesting season, preconstruction survey (CDFW may require protocol-level surveys), construction buffers, habitat avoidance, monitoring, and/or limited operating periods. Impacts to other species would be relatively low; mitigation measures would be similar to those listed above for Swainson's hawk.

Mammals—The Western red bat has a moderate potential to occur in riparian habitat in the White Slough wildlife area. This species would not be affected by construction or operation of the project as long as removal of roost trees is avoided.

Rare Plants—As stated above, special-status plants were not identified during botanical surveys.

Wetlands and Waters of the United States

Field surveys indicate that wetlands and waters of the United States are not present at the ECF site or its laydown areas. Potential waters of the United States are present between the West and East Well pads, Bishop Cut, and the White Slough Wildlife Area. Using selective construction techniques, the air pipelines connecting the ECF with the well pads could avoid wetlands and waters of the United States.

San Joaquin County Multi-Species Habitat Conservation Plan (SJMSCP)

Although the CEC would be lead agency for the project, the project owner may seek coverage under the SJMSCP for most of the state- or federal-listed species. The SJMSCP provides coverage for effects on federally- and state-listed species with implementation of certain prescribed avoidance and minimization measures. Mitigation fees are assessed for habitat loss on a per-acre basis. The SJMSCP would not cover the anadromous fish species under jurisdiction of the National Marine Fisheries Service (NMFS) and also may not cover the giant garter snake, due to the proximity of the project to the White Slough Wildlife Area. Any effects on these species would need to be addressed through separate processes, such as Federal Endangered Species Act Section 7 consultation and the California Department of Fish and Wildlife Section 2081 Incidental Take Permit process.

3. Cultural Resources

A significant amount of analysis, field surveys, desktop surveys, and permitting was conducted for earlier project phases of the KICP for the core drilling and Temporary Site Facility (TSF) installation/operation (see Chapters 5 and 6). In particular, a significant amount of cultural resources (CR) information is included in the EA/FONSI, which is included as a key reference to the ESLPA. In addition to that earlier work, for the commercial-scale project, PG&E conducted a literature search of the KICP project vicinity and intensive pedestrian survey of the project footprint. According to the results of the record search at the California Historical Resources Information System and other sources, a total of eight cultural resources features have been identified within the project area or in the vicinity. The waterway known as Bishop Cut is the only previously documented cultural resource located within the project area. This feature does not meet the criteria for listing in the National Register of Historic Places or California Register of Historical Resources. The archaeological sensitivity of the ECF and linears is considered moderately low, and the sensitivity of the well pad sites is considered low.

PG&E conducted an intensive archaeological survey of the project area, recording five isolated artifact finds—one 1960s era livestock corral, and a recent (20th century) refuse dump. None of these properties appears to meet the criteria for listing in the National Register of Historic Places or California Register of Historical Resources. Similar negative results were noted during surveys conducted in conjunction with the core well drilling and compression testing phases of the project. The project would, therefore, not affect known significant archaeological or historic resources.

4. Geological Hazards and Resources

The project site is in an area of relatively flat topography typical of the California Central Valley and gently slopes to the west. Surficial geology at the project site (both ECF and well pad area) was analyzed using a desktop process as described in the ESLPA. Groundwater at the ECF has been detected at depths ranging from approximately seven to nine feet below ground surface. Groundwater at the well pad sites is maintained at a level of approximately six to eight feet below surface by a system of agricultural drains.

Several active faults exist within 50 miles of the KICP site. These faults are capable of generating maximum credible earthquakes (MCEs) that represent a significant seismic hazard to the project site. No active faults have been mapped crossing the project site, and the site is not within an Alquist-Priolo Special Studies Zone.

Geologic hazards are rated as follows for the project facilities:

- **Seismicity**—If a large earthquake were to cause a rupture to the buried compressed air pipeline, the public could be exposed to hazards associated with sudden release of highly compressed air.
- **Liquefaction**—Hazard of liquefaction is considered moderate, based on the soils present at the ECF and well pads and the risk of a major earthquake.
- **Mass wasting**—Because the site is relatively flat and no significant excavation is planned during site construction, the potential for direct impact from mass wasting at the site is considered low to negligible.
- **Subsidence**—The potential for subsidence as a hazard that could affect the project site is considered low.
- **Expansive Soils**—The KICP site lies in an area where the potential for expansive soils to be present is high.
- **Flooding**—The potential for a 100-year flood event to affect the ECF site is medium to high. Although the King Island gas field is protected by levees, it is possible that the levees would fail during catastrophic storm, flood, or seismic conditions.

No known geologic resources of recreational or scientific value are present at the project site or in the project vicinity. Two active producing gas wells are located on King Island. Although numerous wells have been drilled within two miles of the KICP, most are now labeled as “plugged and abandoned – dry hole” according to the California Division of Oil, Gas and Geothermal Resources (DOGGR) maps.

5. Hazardous Materials Handling

The KICP would use hazardous materials both during construction and during project operation. Most of the hazardous materials that would be used for the project are required for facility operations such as air pollution control, and maintenance, such as lubrication of equipment, or would be contained within transformers and electrical switches. The only regulated substance that would be used for the project at quantities larger than the federal Threshold Quantity is aqueous ammonia. The KICP facility would use aqueous ammonia, stored in a single stationary aboveground storage tank. The tank would be designed to current safety standards. If the aqueous ammonia solution were to leak or be released without proper controls, the ammonia in solution could escape or evaporate as a gas into the atmosphere. Ammonia gas can be toxic to humans at sufficient concentrations. The CEC licensing process requires an off-site consequences modeling analysis, which would need to be conducted by the Project Developer based on the final project design and related considerations.

In addition to the ammonia issue outlined above, small quantities of native natural gas may be entrained with the compressed air withdrawn from the reservoir. This possibility exists during the early operation period of the facility's lifecycle as a result of the presence of a small amount of native gas in the nearly depleted gas field. The gas concentrations in the withdrawal air should be continuously monitored at each well and the gathering piping. The levels should be limited to a safe concentration as determined by a formal HAZOP analysis to be performed during the detailed engineering and design effort. As in indicated in Chapter 6, "Air Injection Test and Analysis," Figures 6-6 and 6-7, the history-matched, calibrated model predicted native gas concentrations of less than 1% during the air injection test with one I/W well.

A preliminary full field development model, which was based on the installation/operation of 25+ I/W wells to support a 300-MW facility, indicated that CH4 (the main component of natural gas) as a percentage of total volume, would peak at approximately 2.9% after the first 18 weekly cycles and would steadily decline to approximately 1.5% after the first 50 weeks. As indicated in Figure 8-5, after the air injection test, the full field model was re-run with updated data collected during the test; as indicated in Chapter 6, the model predicts that CH4 would peak at approximately 1.8% after the first 18 weekly cycles and decline to approximately 1.2% after the first 50 weeks. After two (2) years of operation, CH4 as a percentage of the total volume, would be less than 1%.

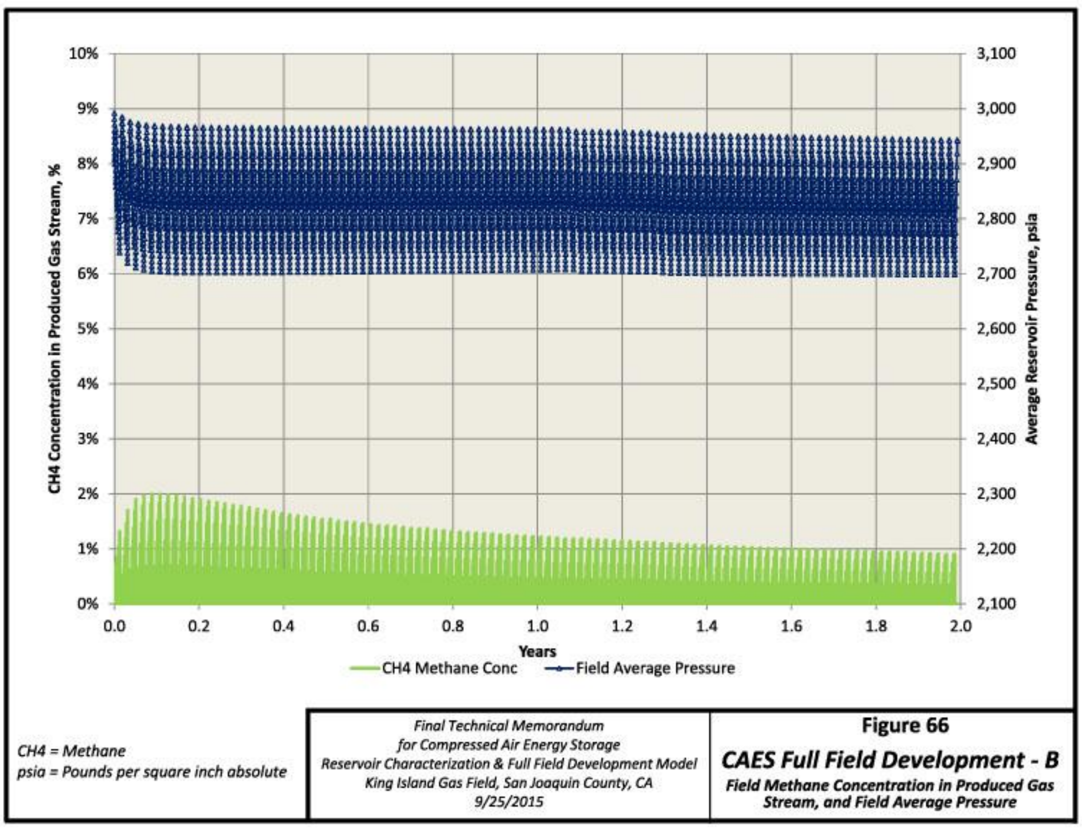


Figure 8-5: CH4 (Methane) Concentration in Produced Gas Stream

Regardless of the modeling results, in addition to individual well monitoring, continuous gas monitoring should take place along the compressed air pipeline and at the ECF site. As a precautionary measure, the air pipeline should have the ability to be purged prior to start-up of the turbo-expansion system. In addition, venting from the I/W wells may occur annually for testing. Based on these design precautions, no significant hazards would be posed to the public or KICP workforce from any entrained gas.

6. Land Use

The KICP ECF site is currently agricultural land and open space. The ECF and staging area west of the ECF are currently corn fields, and the well pads are located within orchards. The area in the project vicinity is developed primarily into agricultural land uses with rural residences, Interstate Highway 5 (I-5) and local roadways, and irrigation canals. No schools, churches, child care/day centers, parks and recreation centers, or historic areas are within one mile of the proposed site.

The ECF site is located on lands designated as Unique Farmland. The well pads, air collection pipeline, and 12-kV service line are in locations designated as Prime Farmland. The main ECF site and east well pad are not under Williamson Act (agricultural tax preserve) contract. The west well pad is located on a parcel under Williamson Act contract. While natural gas extraction activities are considered a permitted use of properties under Williamson Act contract, it is uncertain how the proposed project facilities will be considered by San Joaquin County. If contract cancellation by the County is required for the 6-acre well pad area, mitigation may be required for the conversion from agricultural to non-agricultural use.

The zoning designation for the ECF site is Community Facility. A power plant and its linears are allowable uses in the City of Lodi's Public and Community Facility (PF) zoning designation. Therefore, the project would be consistent with the City of Lodi Zoning designations for the project. In licensing the Lodi Energy Center (LEC), the CEC found that "The PF zoning district applies to areas suitable for public land uses, and allows power plants and gas pipelines under the category of 'Utility Facility.'"

The well pads and linears are located within unincorporated San Joaquin County in areas that are designated in the General Plan for General Agriculture. The permanent well pads are allowable on General Agricultural designated land as long as they satisfy the San Joaquin County General Plan's criteria for the preservation of agricultural lands and compatible uses. The County zoning designation for these areas is also General Agriculture. Minor utility services are a permitted use in the General Agriculture zone; major utility uses are permitted subject to site approval (conditional use permit) in the General Agriculture zone.

7. Noise

The KICP main sources of noise will be the equipment at the ECF. Sources of noise at the ECF site will include the air compressors, turbo-expanders (equipment and stacks), natural gas compressors, cooling tower fans, and pumps. Some of the ECF equipment noise would be taking place most times of the day (when operating), with air compression and injection taking place typically during the off-peak nighttime and early morning hours, and air withdrawal and turbo-expander power generation potentially during the on-peak morning, afternoon, and evening hours. Actual operation of the equipment will depend upon system conditions and needs. Although the expected frequency would be rare, an operational scenario consisting of both compression and power generation is possible. This scenario results in the worst-case noise levels for the KICP, although the results are nearly identical compared with the generation only mode.

Three residences are located approximately 0.5 mile to the north of the power plant site on the opposite side of I-5; these are the closest sensitive noise receptors. Additional residences are located further north beyond 0.75 miles from the project site.

The City of Lodi's noise ordinance prohibits noise that increases the local noise more than 5 dBA over ambient nighttime levels at the property line of any residential property. The San Joaquin County Development Regulations establish daytime hourly average and maximum limits of 50 and 70 dBA, respectively, and nighttime hourly and maximum levels are 45 and 65 dBA, respectively, as more fully described in the ESLPA.

The CEC noise impact analysis process generally starts with ambient nighttime noise levels at the nearest sensitive receptor. An increase over this level of less than 5 dBA attributable to the project would not be considered significant, and an increase of greater than 10 dBA would be considered significant. An increase of 5 to 10 dBA may or may not be significant, depending on the circumstances. The CEC will require an ambient noise survey at nearby sensitive receptors and a modeling analysis to determine the levels of attenuation required, if any, to meet this noise standard. Ambient noise monitoring was not done for this study.

Based on a preliminary engineering design, equipment noise data, and the preliminary plant general arrangement as provided in the Worley Parsons Conceptual Design and Cost Estimate Report (Appendix 8A, Attachment 5, KICP Appendix 5.3F CompTest 05.31.2013.pdf), preliminary acoustic modeling was conducted as outlined in the ESLPA (Appendix 8A, Attachment 7, ESLPA Final Volume 1 Document.pdf; Appendix 8A, Attachment 8, ESLPA Final Volume 2 Appendices.pdf). Because acoustic attenuation analysis/design details were not available in the current Worley Parsons Conceptual Design and Cost Estimate Report (Appendix 8A, Attachment 5, KICP Appendix 5.3F CompTest 05.31.2013.pdf), acoustic modeling incorporated assumed levels of attenuation based on industry standards for light to moderate attenuation, as more fully described and qualified in Chapter 4.1 of the ESLPA. The results of that analysis indicate that, under the worst-case operating scenario (simultaneous compression and generation) and the various assumptions noted, an increase of more than 5 dBA at the nearest receptor is not expected and, as a result, the project impacts are not expected to be considered significant. Figure 8-6 is the noise contour map corresponding to the worst-case operating scenario (refer to the ESLPA for contour maps corresponding to additional scenarios).

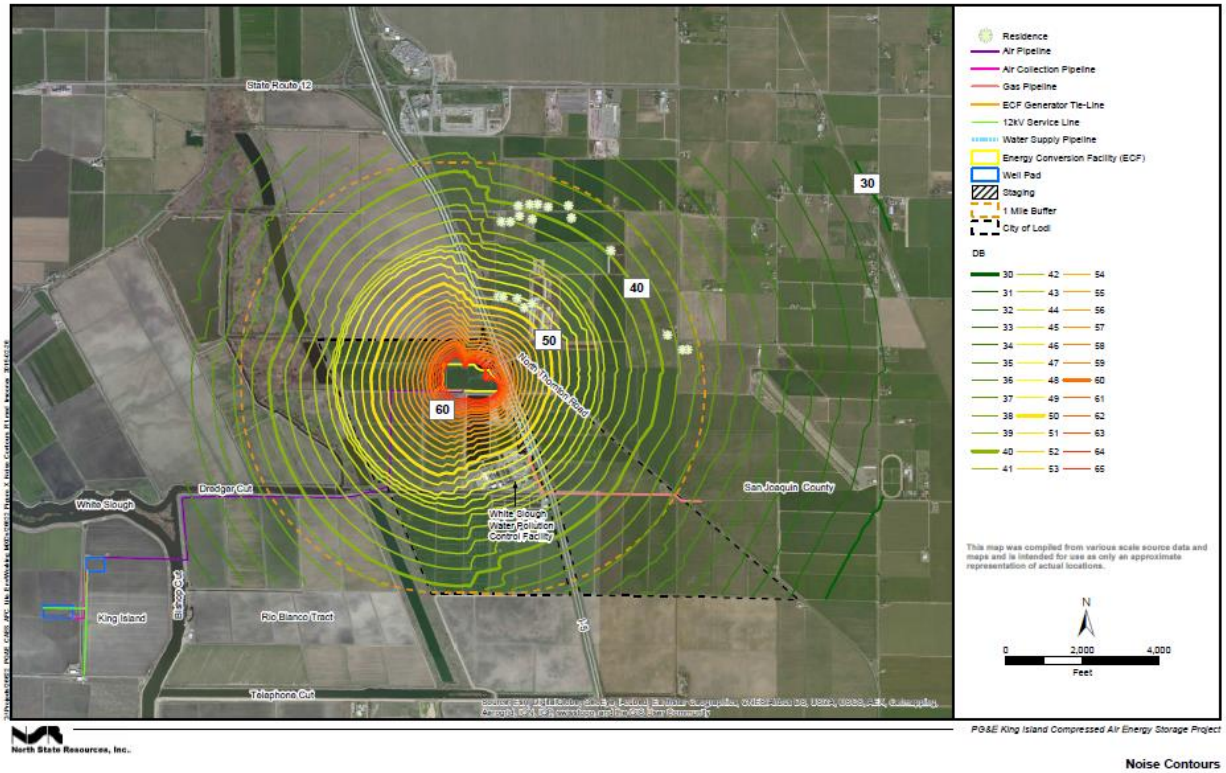


Figure 8-6: Noise Contour Map – Worse-Case Operating Scenario

8. Paleontological Resources

A literature search of the paleontological databases yielded very few records from the areas encompassing the project site facilities. In the area of surficial geology within one mile of the project, no paleontological localities have been recorded within a mile of the site. Furthermore, no paleontological localities are known from applicable formations in San Joaquin County, and this area is assigned low paleontological sensitivity.

9. Public Health

In a traditional AFC, this section presents the methodology and results of a human health risk assessment performed to assess potential impacts and public exposure associated with airborne emissions from the construction and operation of the facility. For the KICP, this feasibility study has not been conducted or included this analysis. Such a study will need to be conducted for the actual AFC license application based on project-specific information. Consequently this section concentrates on other aspects of the public health analysis normally found in this section.

Air will be the dominant pathway for potential public exposure to non-criteria pollutants released by the KICP. Air emissions will consist primarily of combustion by-products produced by the turbo-expander units. Potential health risks from combustion emissions will occur almost entirely by direct inhalation. To be conservative, additional pathways for exposure should also be included in the health risk modeling. The health risk assessment would be conducted in accordance with guidance established by the California Office of Environmental Health Hazard Assessment (OEHHA), the California Air Resources Board (CARB), and the SJVAPCD.

Health and safety hazards due to use of hazardous materials (including aqueous ammonia and native natural gas entrained in the withdrawal air stream) are discussed in the Hazardous Materials Handling section (#5 above) and the Worker Health & Safety section (#16 below).

10. Socioeconomics

Between 2010 and 2013, employment in the Stockton Metropolitan Statistical Area (MSA) increased by about 5%. This 5% increase is lower than California's net increase (about 7%) during the same period. On a percentage basis, the construction sector experienced the largest increase in employment, followed by the transportation, warehousing, and utilities. Based on the MSA's prevailing unemployment rate, adequate labor would likely be available to fulfill KICP's construction labor requirements. Therefore, KICP construction will likely not place an undue burden on the local workforce.

Most of the construction workforce would be drawn from San Joaquin, County. Construction workforce could also be drawn from other nearby counties, especially those in the San Francisco Bay Area, or from out of state, if necessary. Thus, the project will probably not result in an increase in the population of the area.

The construction workforce will most likely commute daily to the project site; however, if needed, numerous hotels/motels are available in San Joaquin County to accommodate workers who may choose to commute to the project site on a workweek basis. Additionally, housing supply is more than adequate within the County for any construction workers who may choose to rent. Since the proposed project site is close to the Bay Area, some of the workers could choose to seek accommodation in the Bay Area. As a result, construction of the proposed project is not expected to increase the demand for housing.

An environmental justice issue could exist if the project created high and adverse impacts that would fall disproportionately on minority members of the local area after all mitigation measures have been implemented. None of the census tracts contains a poverty population. A final determination of the potential for high and adverse human health and environmental impact to occur cannot be made at this time since the project's environmental impacts have not been completely analyzed (for example, public health impact of air emissions). Based on information developed thus far and experience with similar projects, the KICP would not likely pose high, significant, and unmitigated adverse impacts and, therefore, an environmental justice issue will not likely be present in connection with the KICP. While the above information is based on current conditions, it is not expected to change significantly prior to the preparation of the actual AFC license application.

11. Soils

The soils found in the proposed KICP area are nearly level, with an estimated average slope of less than two percent. The erosion potential of the existing soils would vary based on the wetness of the soil, soil compaction, sizes of soil particles, and other site-specific properties. Based on the soil survey information, the soils in the proposed KICP project area are expected to have a slight water erosion potential and a slight to high wind erosion potential.

An important characteristic of the proposed Kings Island CAES project area is the potential for soils with moderate to high shrink-swell potential. The majority of the mapped soils in the general area have a moderate to high shrink-swell potential. The presence of expansive clays in the soil may affect the suitability of the soil as a bearing surface for foundations and pipelines because expansive clays have the potential to shrink or swell in volume with changing moisture content.

The organic nature of the soils at the well pad sites and along portions of the compressed air pipeline has the potential for subsidence when drained and subsequent oxidation occurs. Standard engineering designs and BMPs would address all soil issues.

12. Traffic and Transportation

This section does not include a standard Application for Certification (AFC) traffic impact analysis for construction and operation effects on Level Of Service (LOS) at key intersections and roadway segments since at this time-detailed construction design information is not available, and the exact dates of construction are not certain. Traffic density and LOS could significantly change by the time a project owner submits the final AFC for the KICP.

The following is a summary of the key findings of the existing traffic conditions analysis:

- All of the local roadways in the study area are operating at an acceptable level of service (LOS), based on Caltrans, San Joaquin County, and the City of Lodi traffic impact thresholds
- All of the nearby intersections (where data was available) are operating at LOS C or better
- Several segments of State Route 4 and I-5 currently operate at LOS E or F during at least one peak hour. As a result, construction traffic travelling on these roads would likely be required to arrive and depart outside of peak hours.
- Certain sections of I-5 are currently operating at LOS E on a daily basis.

The imaginary surface extending from the nearest point of the Kingdon Airport runway intersects the location of the KICP exhaust stacks at an elevation of 75 feet above ground surface. Therefore, the project owner would be required to file a *Notice of Proposed Construction or Alteration* with the Federal Aviation Administration for an analysis of hazard to air navigation. The ECF stacks would not be likely to pose structural hazard to air navigation. In some recent cases before the CEC, pilots have raised concerns about thermal exhaust plumes from power plant stacks sited near airport runways posing a possible air turbulence hazard to small aircraft. This is an issue that must be evaluated on a case-by-case basis, depending on the distance from the runway, location in relationship to the takeoff and landing approaches, power plant technology and exhaust gas velocity, and local meteorology and is a potentially critical issue for permitting the KICP. However, this issue was not considered in detail during the LEC licensing process.

13. Visual Resources

The KICP project vicinity is agricultural in character, with row/field crops, grazing, orchards, dairies, vineyards, and sod farms. King Island, including the well pad locations, is nearly entirely agricultural, with orchards and row crops predominant. Residences and associated agricultural facilities are intermittently present along King Island Road, which extends along the perimeter of the island.

Population density in the region is low, and fewer than ten residences are present within 1 mile of the proposed ECF site. The nearest residences to the ECF are concentrated in the land to the northeast, with a cluster of three homes located within 0.5 miles of the ECF site. Two farm residences are approximately 1500 feet just south of the west well pad and are screened from the well pad by the walnut orchard.

The tallest elements within the ECF site are the turbo-expander stacks (two total), which would be approximately 100 feet in height, and the 100-foot-tall towers associated with the 270-foot long generator tie-line connecting the ECF to the existing 230 kV transmission line circuit. As means of comparison, the exhaust stack at the nearby LEC is approximately 150 feet in height. The tallest element in the well field would be the communication antenna for the well field control building, which would be approximately 50 feet in height. Young walnut trees in the immediate area surrounding the well pads are currently between 10 and 15 feet in height, but can be expected to grow to 30 to 50 feet tall by the time KICP construction begins.

The ECF site is expected to be visible from locations throughout the surrounding area, as evidenced by the general visibility of the existing and adjacent LEC plant. Along with the existing Lodi Energy Center (LEC), steam injection (STIG) plant, City of Lodi Water Pollution Control Facility (WPCF), and large-scale agricultural uses, three separate 230-kV transmission tower lines pass adjacent to the ECF. The well pad facilities are likely to be visible from unpaved farm roads adjacent to each of the sites and in longer, elevated views from the levee along the perimeter of King Island.

The project would likely be visible in views from various key observation points (KOPs) but would be unlikely to have a significant and adverse effect on project area visual resources. Visibility of the project would be determined by preparing simulated views of the final project design from the KOPs as part of the CEC licensing process and further analysis.

Because of the character of the area and the presence of other plumes from other nearby sources, including the existing LEC facility, cooling tower vapor plumes that would occur at the ECF would not be likely to result in a significant impact on the visual character of the area.

14. Waste Management

A Phase I Environmental Site Assessment and Limited Soil Investigation were conducted for the ECF site. These studies (see ESLPA), which included literature/database research, interviews of people familiar with the property, a field visit, and collection and analysis of subsurface soils at four locations, did not identify any controlled recognized environmental condition, as defined in the applicable ASTM standards. The site assessment and soil analysis reports concluded that the potential presence of any residual agricultural chemicals in soil or groundwater at the site from historical agricultural operations would represent a *de minimis* condition, and soil pesticide and herbicide levels were not detected above the laboratory reporting limits.

An examination of the California Department of Toxic Substances Control (DTSC) Hazardous Waste and Substances Site List (Cortese List) shows a location over six miles from the ECF as the closest Cortese-listed property. The KICP site is not located on a Cortese-listed site and is not affected by the site six miles away, or any of the other listed sites.

Project construction and operation would generate both liquid and solid hazardous and non-hazardous wastes. Solid non-hazardous wastes would include materials normally produced for a traditional Simple Cycle Gas Turbine (SCGT) power plant. Facility operations and maintenance activities wastes would also include materials typically produced for a traditional SCGT plant, including refuse generated by workers and small office operations, and other miscellaneous solid wastes. This waste would add to the total waste generated in San Joaquin County and in California. However, adequate recycling and landfill capacity is available in San Joaquin County to recycle and dispose of the waste generated by the KICP.

Water from washdown, sample drains, equipment leakage, and drainage from facility equipment would be collected in a system of floor drains, hub drains, sumps, and piping, and would be routed to the facility's oil/water separator. If contamination is present, the water would be trucked off site for disposal at an approved wastewater disposal facility. If sampling results show no contamination, the water would be discharged, and the oily sludge would be shipped to an appropriate disposal facility.

Non-hazardous wastewater would also come from the I/W wells as native water entrained in the withdrawal stream and also as condensed vapor resulting from expansion of the compressed air on withdrawal. This water would be captured at the wellhead and reinjected into a non-potable aquifer situated geologically below the air reservoir using the injection wells at the well pad site(s) and/or ECF Site, as more fully described in the UICPA.

Hazardous waste generated would include waste lubricating oil, used oil filters, and chemical cleaning wastes. Chemical cleaning wastes, consisting of alkaline and acidic cleaning solutions, may be generated from periodic cleaning of the piping. These wastes may contain high concentrations of heavy metals and would be collected for offsite disposal. The waste oil would be recycled. Hazardous waste treatment and disposal capacity in California is more than adequate. Therefore, the effect of the KICP on hazardous waste recycling, treatment, and disposal capability would not be significant.

15. Water Resources

The KICP is on the eastern edge of the Sacramento-San Joaquin River Delta (Delta). Over time, the Delta has been highly modified by channelization and water diversions for municipal, industrial, and agricultural uses, creating a regional patchwork of islands and tracts surrounded by natural and man-made channels and sloughs. King Island and the surrounding waterways are examples of this development.

The KICP ECF and well pad sites are located on agricultural lands, which are drained by small, unnamed drainage features. At the ECF and immediate surroundings, all surface drainage is collected and returned to the Lodi WPCF. The air pipeline route and well pads are below sea level, so collected runoff is pumped over the levees into the adjacent sloughs, which flow to the west of the project site and continue to the San Joaquin River.

Potable water would be used for domestic uses, such as drinking, washing, eye-wash stations, and sanitary facilities. The KICP would obtain potable water from a new onsite groundwater well at the ECF, using an estimated 0.8 acre-feet of water per year on average. Wastewater from these uses would be collected and disposed of in the ECF on-site septic system.

Process water would be recycled water from the adjacent City of Lodi White Slough WPCF. Approximately 1000 acre feet per year of recycled water would be used for cooling, as well as for NOx control and other industrial purposes based on base case plant design and load forecasts. Due to the high level of reliability of water from WPCF, no backup water supply is planned for the project at this time.

Wastewater from KICP ECF power generation and compressor cooling would be discharged directly to a Class I underground injection well that would be constructed on the ECF site and/or piped to injection wells located at the well pads. Wastewater would be injected from the injection wells into the non-potable aquifer situated geologically below the air reservoir. On average, the KICP would discharge several hundred gallons of process water per minute that would be injected into the wastewater wells. A Class I underground injection control (UIC) well permit package would be submitted to the U.S. Environmental Protection Agency (EPA) Region IX, Water Department. Class I permits allow the injection of hazardous and nonhazardous fluids (industrial and municipal wastes) into isolated formations beneath the lowermost underground source of drinking water. This application/process would also need to incorporate UIC permitting of I/W wells as summarized below and outlined in detail in the UICPA (included as Appendix 2B to the ESLPA).

The plant wash water from the equipment drains would pass through an oil-water separator and wastewater sump before it is discharged to the atmosphere through evaporation in the cooling tower. The oil and sludge removed from the washwater would be disposed of offsite. Wastewater from the safety showers and eye wash would be discharged to the on-site septic system.

The KICP site is in the 100-year flood plain (Zone AE) as defined by FEMA. The potential for a 100-year flood event to affect the site is medium to high. The KICP site is on the eastern edge of the Delta and is protected from the Delta by a system of levees. The well pads are located on King Island in unincorporated San Joaquin County also within the 100-year floodplain, designated by the County as Special Flood Hazard Areas (SFHA). King Island is hydrologically isolated and surrounded by levees, but because the well pad elevations are approximately 5 feet below mean sea level (MSL), they could be inundated in the event of a levee breach. For this reason, critical equipment at the well pads would be located on platforms elevated above the flood level, and all equipment would be designed to cease operation safely in the event of a flood, per San Joaquin County Development Title for SFHAs and good engineering safety practices. Because it is only 1-2 feet below the FEMA flood elevation, the ECF flood design involves simple foundation/grading provisions to maintain adequate plant access.

16. Worker Health and Safety

Workers will be exposed to construction and plant operation safety hazards. Hazard analysis identifies the hazards anticipated during construction and operation, and indicates which safety programs should be developed and implemented to mitigate and appropriately manage those hazards. Programs are overall plans that set forth the method or methods that will be followed to achieve particular health and safety objectives corresponding to the hazards likely to be present as determined through the hazards analysis. For example, the Fire Protection and Prevention Program will describe what has to be done to protect against and prevent fires. The Emergency Action Program/Plan will describe escape procedures, rescue and medical procedures, alarm and communication systems, and response procedures for every hazardous material that can migrate, such as ammonia. The programs or plans are set forth in written documents that are usually kept at specific locations within the facility.

Each program or plan will contain training requirements translated into detailed training courses provided to plant construction and operating personnel, as needed. Hazards that present themselves differently at KICP than at a traditional gas-fired power plant include the following:

- Native natural gas may be entrained in the reservoir air withdrawal stream in concentrations that may be hazardous to those working around the well pads and pipeline. This hazard will be controlled by instrument monitoring to measure the concentrations at the wellhead and to control or stop the withdrawal at that wellhead as necessary if concentrations approach hazardous levels.
- The compressed air pipeline will carry a high-pressure air stream that would be hazardous to workers in the event of a pipe system breach.
- Four fire stations are in the Woodbridge Fire Protection District system, the closest of which is approximately 1.25 miles from the ECF. Approximate response time from the closest station to the project site would be 7 to 10 minutes. Mutual aid response would come from the other three local stations, as well as the City of Lodi and City of Stockton fire stations, depending on situation and need.

8.4 ALTERNATIVES

The core objective of PG&E's CAES project is to provide approximately 3000 megawatt-hours (MWh) of energy storage capacity and grid support ancillary services capability to the California Independent System Operator (CAISO)-controlled grid. An important part of this objective is to demonstrate understanding and experience with the CAES technology using a depleted natural gas field as an air storage reservoir. As discussed in detail in Chapter 3, the screening process to identify a site to meet these and related objectives involved evaluation of 148 depleted gas field sites. Reservoir selection criteria included specific technical criteria such as cumulative gas production, water drive mechanism, porosity, permeability, and net sand thickness, as detailed in Chapter 4. This process eventually culminated in the selection of the King Island gas field as the preferred site for the air storage reservoir.

Given the criticality of the reservoir in driving the siting process, selection of the KI reservoir established the foundation for the KICP base case. In addition, other siting, technology, and design features were selected for the KICP base case based on the preferred economics, site control feasibility, ease of permitting, and other criteria. Alternatives to selected aspects of the KICP siting and design base case were considered, and evaluated in contrast with the base case relative to the likelihood of best achieving the project objectives.

With the choice of the King Island site, PG&E also considered alternatives sites within 5 miles of the King Island well field as potential alternative ECF sites. The alternative site chosen for comparison is located near the junction of I-5 and State Route 12, approximately 1.3 miles north of the proposed site. This site (referred to as the SR-12 site) is also located near a high-pressure natural gas pipeline and adjacent to the Gold Hill-Eight Mile Road 230-kV transmission line. The proposed site best meets the project objectives. The SR-12 site would likely be more difficult to permit, because it is prime agricultural land that is zoned for general agriculture. In addition, the alternative site is adjacent to a wildlife preserve, which could pose land use and biological resources concerns.

Alternative compressed air and natural gas pipeline routes were also considered and found to be similar to the proposed routes in terms of cost and environmental impact. Alternative generator tie-line routes were not considered, because the ECF is located adjacent to the Gold Hill-Eight Mile Road 230-kV transmission line.

Selection of the base case cooling technology was a key ECF design consideration. Although Zero Liquid Discharge (ZLD) was considered and evaluated, the use of recycled water was selected because of the nearby available and reliable source as well as the "re-claimed" nature of the supply.

8.5 KICP RESERVOIR—SPECIAL PERMITTING CONSIDERATIONS

In addition to the above, more traditional AFC-centric permitting considerations, KICP development will require permitting processes unique to development of an underground CAES reservoir in California, as outlined below and as fully described in the UICPA report.

The King Island reservoir was selected for CAES development following detailed evaluation of its surface and subsurface attributes, significant performance testing of the reservoir, and various other considerations. The results of detailed engineering analysis and testing indicate that, with an established air bubble of approximately 8 Bscf (billion standard cubic feet), the reservoir can support a 3000 MWh power generation facility in a variety of operating scenarios. The key subsurface elements for development of a depleted natural gas reservoir for CAES operations includes high-capacity injection/withdrawal (I/W) wells, observation wells to monitor conditions within and around the reservoir, and water injection wells for the disposal of produced process waters. Facilities will be needed to dispose of water produced during withdrawal operations and potentially for ECF wastewater disposal.

8.5.1 EPA/UIC

The Safe Drinking Water Act was passed by the U.S. Congress in 1974 to ensure security of various sources of drinking water. Specific requirements are found in Title 40 of the Code of Federal Regulations. EPA has been charged with enforcing these regulations, and the Underground Injection Control (UIC) program is a key part of their regulatory oversight. The Ground Water Office of EPA Region IX, located in San Francisco, would be responsible for processing all UIC permits for the KICP.

To provide a roadmap and high-level analysis of the EPA UIC permitting process to potential developers of the permanent KICP, a UICPA report was prepared, including a UIC permit application template with representative information gathered during the earlier testing phase and an assumed base case development scenario. This base case is consistent with assumptions and design criteria provided in other key project reports developed for the commercial-scale KICP project and referenced throughout the ESLPA prepared for the KICP. Although the UICPA focuses on the KICP, much of the content and processes are relevant to CAES projects sited at other depleted gas reservoirs and potentially other types of underground reservoirs.

Reservoir modeling of the base case bubble building and full operations provide reasonable estimates for the operating characteristics pertinent to a UIC permit. Variations from that base case would require changes to the permit application information provided in the report. Users should keep in mind that much of the actual application will need to be redrafted with information specific to the final development and operating plans.

Based on preliminary discussions with EPA, at least two UIC permits will be required for two very different operations: 1) injection of air into the King Island reservoir, and 2) injection of waste water from CAES operations (well field and ECF) into an approved disposal zone. Certain sections of the permit application(s) will require different analysis and discussion of both the air and water injection activities. Because these activities are occurring in different underground formations, the analysis of the impact on each can yield significantly different results. Attempts have been made in this report to indicate where these separate analyses are required.

8.5.2 DOGGR

The California DOGGR regulates all gas and oil well activities in the state. A key role of the agency is to establish "Field Rules" for well drilling and well operation/maintenance for each natural gas field (see Chapter 4, "Reservoir Screening and Site Identification," for a definition of Field Rules). Field Rules may expire after a gas field has been depleted and production discontinued. Where field rules are still active, issuance of a well drilling permit is considered ministerial. However, where field rules must be re-established, DOGGR must conduct an environmental review of proposed new field rules and drilling activity under the California Environmental Quality Act (CEQA). The King Island site had active field rules, thus the issuance of well drilling permit was considered ministerial.

Appendices

Appendix 8A, Attachment 1, Final Environmental Assessment Appendices.pdf.
Appendix 8A, Attachment 2, Final Environmental Assessment.pdf.
Appendix 8A, Attachment 3, Finding of No Significant Impact.pdf.
Appendix 8A, Attachment 4, KICP Appendix 5.3E SWCA GeoTest 2012.pdf.
Appendix 8A, Attachment 5, KICP Appendix 5.3F CompTest 05.31.2013.pdf.
Appendix 8A, Attachment 6, KICP Appendix 5.3G Subsurface Testing KICP Compression.pdf
Appendix 8A, Attachment 7, ESLPA Final Volume 1 Document.pdf.
Appendix 8A, Attachment 8, ESLPA Final Volume 2 Appendices.pdf.

Chapter 9
Request for Offer (RFO) Process and Results

9.1 INTRODUCTION

This chapter summarizes the Request for Offer (RFO) process that PG&E conducted in 2015 and 2016 to identify and qualify third parties with interest in developing and operating a CAES facility in California. The chapter outlines the step-by-step process of engaging market participants, the offers received, and the rationale behind the best offer.

9.2 RFO PROCESS

The CAES RFO was launched on October 9, 2015 to determine the interest and qualifications of potential third parties to develop, construct, own, operate, and maintain a CAES facility, and to seek associated bids.

The RFO process and results would assist PG&E in determining the technical capabilities of independent market participants to undertake the development of a CAES facility in California, provide the market's perspective on the cost of developing, owning and operating a CAES facility, and allow PG&E to analyze the value of the CAES facility for grid operations based on the offerings provided. A participants' webinar was held on October 29, 2015 to describe the RFO process to potential bidders.

As part of the RFO protocol, participants were required to execute non-disclosure agreements in order to have access to an electronic "data room," which contained all of the relevant documents associated with the CAES project at that time, including reservoir preliminary design and analysis, energy production facility preliminary design, permitting reports, land acquisition agreements, core well samples, air injection and withdrawal test results, etc.

In January 2016, after allowing enough time to review the extensive data room materials, PG&E met in person with each participant team to answer their questions about the technical materials in the data room and the term sheets or the RFO process, and to assess their experience, their qualifications, and the technical approach they would take to develop a CAES project.

In February 2016, PG&E held individual conference calls with each of the participants to answer questions they raised in the in-person meetings but which PG&E was unable to answer at that time. In response to these interactions, PG&E agreed to consider making some changes to the CAES agreement term sheet.

Also in February, PG&E worked on development of a CAES-specific evaluation model to be used to compare bids against each other and against storage bids from a different, earlier solicitation. The evaluation model calculates the net market value of a project, based on the calculated California Independent System Operator (CAISO) market revenues for capacity and energy services provided by the project minus the costs paid by the Buyer to the Seller. As part of the RFO protocol, Sellers are required to submit an Offer Form that, among other elements, provides comprehensive operational performance parameters for the project. These parameters define the capacity and energy capabilities of the project for use in the valuation model. Before PG&E would be willing to submit a potential CAES project to the California Public Utility

Commission (CPUC) for approval, PG&E would want to be sure that the CAES project is economically competitive with alternative storage technologies.

On March 30, 2016, PG&E released a revised term sheet for the CAES Agreement, along with term sheets for two other agreements: Resource Adequacy (RA) Only; Capacity Storage.

Some revisions to the term sheet were made in response to participants' expressed concerns over schedule and project cost, as well as operational performance in the initial years. Such revisions included a reduction in financial impacts and termination risk to the Seller if the project availability in the first two years of operation is low; a termination right for either Buyer or Seller if the project is not approved by the CPUC within one year of requesting approval; a Seller's right to reduce the capacity of the project by up to 50% prior to December 31, 2019; and, a Seller termination right within one year of CPUC approval of the project.

The CAES Agreement is similar to a traditional power purchase agreement, and was structured with elements from PG&E's energy storage and tolling agreements.

The RA Only Agreement provides capacity payments to the Seller in exchange for the Seller providing RA attributes to the Buyer. The Seller receives all market revenues from the operation of the facility; in exchange for getting these market revenues, the Seller in principle should be able to offer a lower capacity payment price than it would offer if the Buyer were to receive the market revenues as in the CAES Agreement.

The Capacity Storage Agreement is similar to the RA Only Agreement, except that the Seller also would pay the Buyer a synthetic market revenue payment based on Seller-defined capacity and energy service capabilities of the project and settled CAISO market prices for energy and ancillary services. Participants were told that they could bid for any or all of the three agreement structures. PG&E also released a revised Offer Form in early May 2016.

9.3 RFO RESULTS

In late May 2016, some of the participants informed PG&E that they would not be submitting offers, which were due June 1, 2016. Some of the reasons that these participants cited for not submitting a bid included concerns over the tested performance of the reservoir and over the commercial and technical readiness of the participant's chosen compression and generation equipment.

On June 1, 2016, PG&E received the offers for the CAES RFO and began the process of performing the market valuations of the proposed projects. In general terms, offers were not competitive with the executed storage contracts from PG&E's 2014 Storage RFO.

PG&E was surprised with this result, because its previous analysis suggested that a CAES project had the potential to be competitive with alternative storage technologies. PG&E held discussions with bidders to better understand what drove the bid prices. In summary, higher-than-expected bid prices were due to a combination of factors:

- Contractual financial impacts if the project operates at low availability, especially in light of uncertain withdrawal air composition (methane content, depleted oxygen);
- High material costs due to the potential for corrosion;
- Uncertainty in major equipment costs in 2019 (when equipment orders are expected to be placed);

- Inability of major equipment vendors to provide performance guarantees given the uncertain composition of the withdrawal air stream;
- Need to keep expensive equipment spares because of the long-lead time for their manufacture and the contractual availability requirements;
- Incomplete knowledge of the underground characteristics of the reservoir (reservoir performance is based on test results from one well), and the resulting uncertainty over the number of reservoir wells needed for the project;
- Cost of withdrawal air processing equipment and the time required to manage withdrawal air composition issues while still meeting the contractual performance requirements;
- Compromised ability to manage the methane and oxygen concentrations in the withdrawal air due to Buyer's right to schedule dispatch of the project (methane and oxygen levels depend upon the timing of injection and withdrawals);
- Permitting risk (including jurisdictional uncertainties) and the Buyer's contractual termination right if commercial operation does not occur by 2024 (as needed to satisfy Buyer's storage mandate issued by the CPUC).

Given the lack of competitive bids, the bidders were notified on August 3, 2016 that they did not make the short list and the RFO was closed.

Appendices

Appendix 9A, Attachment 1, CAES Offer Form
Appendix 9A, Attachment 2, CAES Term Sheet
Appendix 9A, Attachment 3, Resource Adequacy Only Term Sheet
Appendix 9A, Attachment 4, Capacity Storage Term Sheet
Appendix 9A, Attachment 5, RFO Protocol

Chapter 10
Conclusions and Recommendations

10.1 CONCLUSIONS

The project demonstrated the technical feasibility of using an abandoned natural gas reservoir for storing high-pressure compressed air for a 300-MW-by-10-hour CAES facility. The reservoir can accommodate the flow rates and pressures necessary for the operation of the facility, but some design and operational constraints will have to be properly managed. The estimated high cost of a CAES facility relative to the cost of alternative energy storage technologies will also have to be addressed. Listed below are the key findings of the project.

1. The air injection and withdrawal cycles must be carefully managed to avoid having excessive concentrations of methane in the withdrawal air stream.

   Prior to the start of the air injection testing program, the residual gas in the King Island reservoir consisted of 92% methane. To minimize mixing of this methane with injected air, an air bubble is created in the reservoir of much greater volume than the volume of air needed for a daily withdrawal cycle of the CAES facility. Air injected into the reservoir pushes the methane away, creating an air bubble around the injection well-bore. The bubble will partially insulate the daily working volume of air from the residual natural gas (and also water) in the reservoir by moving the interface between the air and the methane far away from the well-bore. The potential for mixing is greatest at the well-bore, where flow can be very turbulent. Far away from the well-bore, at the interface between air and methane, low-velocity laminar flow prevails in the porous rock medium, and mixing is limited. Multiple days or potentially even weeks of "shut-in" time for the reservoir are expected to be possible because of the very slow rate of mixing of air and methane.

   It is important, however, to maintain the size of the air bubble by balancing the injection and withdrawal cycles. The King Island CAES project was modeled under the assumption that there would be an injection / withdrawal (I/W) cycle each weekday, and continuous injection over the weekend. The model calculates that if only two or three of the daily injection cycles are skipped, but the withdrawal cycles continue, the methane concentrations in withdrawal air will become unacceptable in some wells. The model also predicts that the effects of a skipped cycle can be overcome by subsequent over-injection to restore the size of the bubble and return the methane concentration to acceptable levels. It may be necessary in the initial years of operation, when the volume of methane in the reservoir is greatest, to limit the duration of continuous discharges from the reservoir.

   Methane levels can also be reduced by flushing air containing residual methane out of the reservoir (e.g., during the bubble build and commissioning phase), and by methane being drawn out of the reservoir through a gas production well (e.g., by the holder of the gas rights). Both of these measures, however, come at the cost of the compression energy to support the flushes and gas production. Methane levels will also naturally decline over time as low levels of methane are continually drawn from the reservoir with the withdrawal air.

For the methane that ends up in the withdrawal air stream, the simplest way to manage it would be to burn it along with the pipeline methane consumed in the generation system combustors. There is a limit to the amount of methane that can be taken in the air stream directly into the combustor without compromising safety or combustion stability (and the associated impacts on emissions and part load turndown). During PG&E's compression testing program, a limit of 2% methane (half the lower explosive limit at ambient temperature and pressure) was selected as the basis of the design for the reservoir system, but this level may be too high for some generation system combustors. When operating, if the methane concentration should approach the design limit, a simple fix would be to temporarily shut wells with the highest methane concentrations and draw more flow from the remaining wells. A more robust solution, but at a cost, would be to install additional I/W wells; however, there may not be enough space for additional wells in the current King Island project plan.

2. Withdrawal air from the initial cycles of the King Island reservoir are expected to be depleted in oxygen and unable to support normal operation in the CAES Energy Conversion Facility system; however, this problem is expected to be soluble by doing multiple reservoir flushes with sufficient hold periods to oxide all the oxidizable minerals.

   In the compression testing program, injected air was found to have reacted with some of the minerals in the reservoir (e.g., pyrite, siderite) at a rapid rate. At the end of the ambient air testing, the oxygen was reduced from an inlet concentration of 21.6% to approximately 2% in the withdrawal stream, although a small portion of this reduction may have been a result of air mixing with the oxygen-depleted nitrogen bubble initially injected as part of the test. After all the oxidizable minerals have been oxidized through interaction with injected air, the withdrawal air oxygen content will return to normal. Based on an analysis of the test results and of the minerals in reservoir core samples, it was estimated that the amount of oxygen in several reservoir pore volumes of fresh air would be required to oxidize all of the readily oxidizable minerals. To allow enough time for the reactions, each pore volume might need to remain in the reservoir for some days or weeks, ideally during the commissioning phase of the project. The oxygen consumption would occur more slowly during daily cycling of the reservoir, but not necessarily slow enough to allow for operation of the power generation system until most of the oxidizing minerals are oxidized. The reservoir also contains much slower oxidizing minerals (e.g., iron-bearing clay), but these are likely to have a negligible impact on oxygen concentration in withdrawal air during daily cycling operations.

3. Additional wells will be needed to remove water from the reservoir during the building of the air bubble.

   To build the initial air bubble in a reasonable amount of time, and without exceeding the pressure limit of the wells, water will have to be continuously removed from the reservoir as the air is injected into it. Without water removal, it would take an estimated 10 years to create the initial air bubble. With dedicated wells for water removal, the time is roughly estimated at 18 months. The recommended approach for removing the water is to have separate water removal wells, rather than having to remove the water from the air withdrawn in the I/W wells. The project design calls for 29 air I/W wells, four water withdrawal wells, and two water disposal wells (to redeposit the water to a different part of the aquifer where it won't immediately re-enter the air bubble portion of the reservoir).

4. Alloyed or coated steels are expected to be needed in well materials to withstand corrosive well water.

   Evaluation of the chemistry of water produced during the compression test indicates that it will have a tendency toward corrosion and is unlikely to deposit scale (which would tend to lower the corrosion rate). The water should be evaluated by a corrosion engineer to support appropriate material selection for well casings, screens, tubulars, collection piping, and other surface and subsurface equipment. Internal coatings and linings on piping and well-bore tubulars, and/or use of corrosion-resistant alloys, are also likely to be warranted to limit corrosion effects. Well cement selection should consider how the water chemistry is affected by oxidation reactions. In addition, measures to manage production of water from I/W wells should be evaluated to decrease the potential for corrosion in I/W wells and CAES piping and equipment.

5. A CAES project at the King Island reservoir is not currently economically competitive with alternative technologies providing storage services under comparable commercial contract structures.

   PG&E conducted a competitive solicitation to award a power purchase agreement for energy products from a new CAES facility that would be designed, constructed, operated, and maintained by a bidder if awarded a contract. The bids received from this solicitation were not competitive with executed agreements from PG&E's most recent energy storage solicitation; thus, the CAES solicitation process was ended before proceeding to the negotiation stage. Additional development work listed below may help future bidders of CAES projects that use abandoned natural gas reservoirs better understand cost and performance issues and allow them to offer more competitive bids in storage project solicitations.

10.2 RECOMMENDATIONS

To further assess and manage the risks that come with a CAES project using a depleted natural gas reservoir, the following additional development work is recommended:

1. Obtain additional core samples to help to assess the variability of key reservoir attributes (e.g., permeability, distribution of oxidizable minerals and potential precipitates) over the full extent of the reservoir.

2. Complete additional I/W wells at other locations in the reservoir and then conduct additional tests to better characterize full-scale operations with respect to methane and oxygen content in the withdrawal air; produced water chemistry and the potential for scaling and corrosion; and, precipitation of iron oxide or other solids and their impacts on reservoir porosity and permeability.

3. Test the Energy Conversion Facility combustor over the range of expected concentrations of methane and oxygen in the withdrawal air, and make modifications to improve the combustor's stability, emissions, and turndown capabilities. This should enable the Energy Conversion Facility equipment vendor to provide more expansive performance guarantees to a potential CAES project developer.

4. Evaluate the cost and performance of adiabatic CAES technology (i.e, air compression, storage and expansion, but without firing of natural gas fuel). For projects in California, there is an energy resource “loading order” policy that provides a higher priority to investment in energy efficiency, demand response, renewable energy and distributed generation than investing in fossil fueled power plants. Given this preference, adiabatic CAES technology may be preferred over conventional CAES technology.

5. Evaluate, develop and test methods for removing methane from the reservoir withdrawal air. Methane removal will be more difficult for adiabatic CAES projects because, unlike conventional CAES projects, they will not be able to use the relatively simple solution of burning it in the Energy Conversion Facility combustor.