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Geothermally Coupled Well-Based Compressed Air Energy Storage

December 2015

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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy under Contract DE-AC05-76RL01830

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Richland, Washington 99352

Summary

As the United States and other nations shift toward an electric power generation portfolio focused more heavily on renewables and low-carbon energy sources, mitigating the intermittency inherent with wind and solar power generation has become crucial to maintaining stability and reliability in the nation's electric transmission and distribution systems. Because the rising carbon prices that are expected to incentivize renewables deployment may also increase the cost of traditional grid balancing resources—particularly resources provided by peaking gas facilities, which typically emit CO_2 at higher rates than baseload gas plants—technologies that can offer balancing and ancillary services at lower CO_2 emissions rates could become increasingly favorable over time. Along with pumped hydroelectric storage, compressed air energy storage (CAES) is one of the few existing technologies capable of providing grid-scale energy storage.

However, current and past commercial implementations of CAES have paired the air storage with a natural gas-fired power plant, creating a long carbon shadow associated with such capital investments. Previous work by McGrail et al.[1, 2] has evaluated the possibility of pairing CAES with geothermal resources in lieu of a fossil-fired power generation component, and suggests that such applications may be cost competitive where geology is favorable to siting both the geothermal and CAES components of such a system. Those studies also note that the collocation of subsurface resources that meet both sets of requirements are difficult to find in areas that also offer infrastructure and near- to mid-term market demand for energy storage. This study examines a novel application for the compressed air storage portion of the project by evaluating the potential to store compressed air in disused wells by amending well casings to serve as subsurface pressure vessels (Figure S.1). Because the wells themselves would function in lieu of a geologic storage reservoir for the CAES element of the project, siting could focus on locations with suitable geothermal resources, as long as there was also existing wellfield infrastructure that could be repurposed for air storage.

[1] McGrail, B. P., et al. 2013. *Technoeconomic Performance Evaluation of Compressed Air Energy Storage in the Pacific Northwest.* PNNL-22235. Pacific Northwest National Laboratory, Richland, WA.
[2] McGrail, B. P., et al. 2015. *Geothermal-Coupled Compressed Air Energy Storage*. PNNL-SA-109815. Pacific Northwest National Laboratory, Richland, WA.

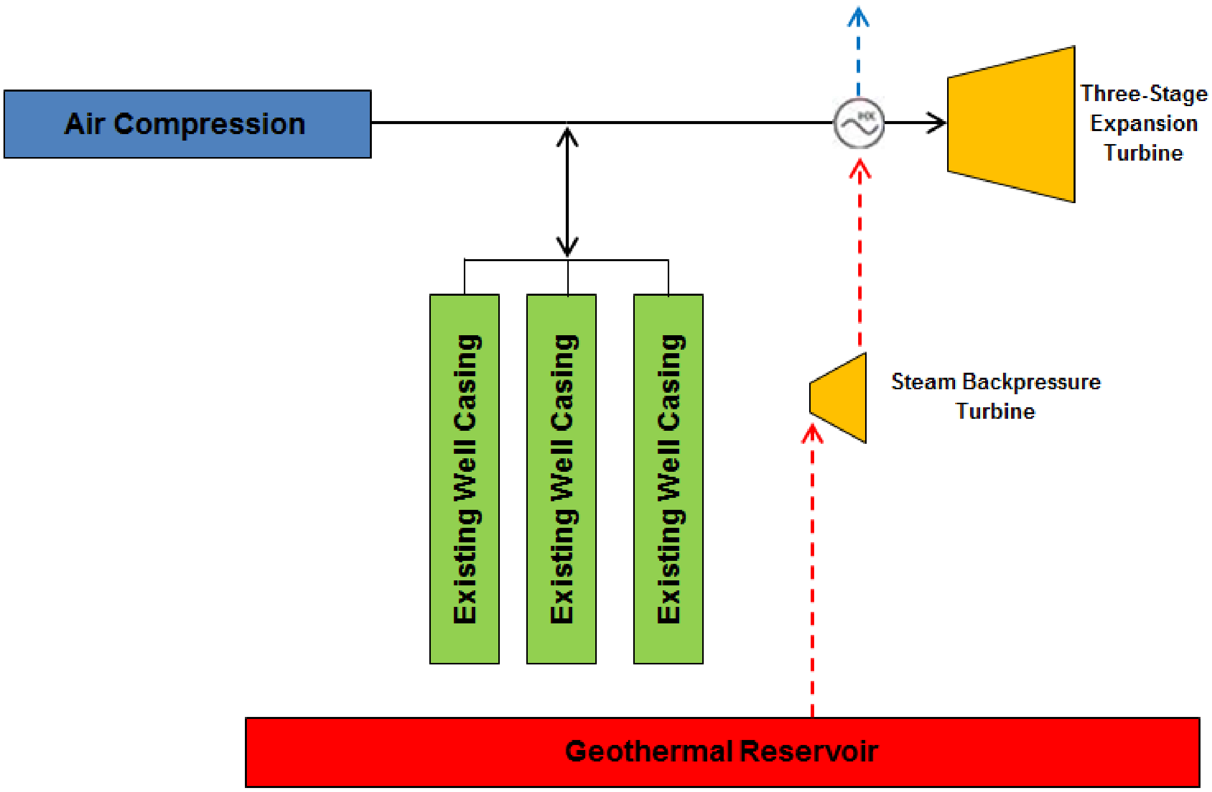

Figure S.1. Geothermal-Coupled CAES Concept Using Existing Well Casing for Air Storage

Existing wellfields abound in the United States, and with current low energy prices, many recently productive fields are now shut in. Should energy prices remain stagnant, these idle fields will be prime candidates for decommissioning unless they can be transitioned to other uses, such as redevelopment for energy storage. In addition to the nation's ubiquitous oil and gas fields, geothermal fields, because of their phased production lifetimes, also may offer many abandoned wellbores that could be used for other purposes, often near currently productive geothermal resources. These existing fields offer an opportunity to decrease exploration and development uncertainty by leveraging data developed during prior field characterization, drilling, and production. They may also offer lower-cost deployment options for hybrid geothermal systems via redevelopment of existing well-field infrastructure.

This project assessed the technical and economic feasibility of implementing geothermally coupled well-based CAES for grid-scale energy storage. Based on an evaluation of design specifications for a range of casing grades common in U.S. oil and gas fields, a 5-MW CAES project could be supported by twenty to twenty-five 5,000-foot, 7-inch wells using lower-grade casing, and as few as eight such wells for higher-end casing grades. Using this information, along with data on geothermal resources, well density, and potential future markets for energy storage systems, The Geysers geothermal field was selected to parameterize a case study to evaluate the potential match between the proven geothermal resource present at The Geysers and the field's existing well infrastructure.

Based on calculated wellbore compressed air mass, the study shows that a single average geothermal production well could provide enough geothermal energy to support a 15.4-MW (gross) power generation facility using 34 to 35 geothermal wells (K-55 casing) repurposed for compressed air storage, resulting in a simplified levelized cost of electricity (sLCOE) estimated at 11.2 ¢/kWh[1] (Table S.1). Accounting for the power loss to the geothermal power project associated with diverting geothermal resources for air heating results in a net 2-MW decrease in generation capacity, increasing the CAES project's sLCOE by 1.8 ¢/kWh.

Table S.1. Plant Capacity and Economic Indicators, Base Configuration for The Geysers

	Compression		Generation		Round Trip Efficiency	Estimated Capital Cost	Estimated Cost per kW	Simplified LCOE
	MW	MWh	MW	MWh	(%)	(million $)	($/kW)	(¢/kWh)
Gross	9.5	102	15.4	61.6	60	$ 33.1	$ 2,151	11.2
Net			13.4	53.6	52		$ 2,470	13.0

If growing demand for zero-emissions balancing options were to incentivize deployment of larger CAES systems, assuming the same utilization rate, capital costs, and operations and maintenance costs, a 46-MW facility (commensurate with 105 repurposed geothermal wells at assumed conditions) could see an estimated cost per kilowatt as low as $1,709[2] and a corresponding sLCOE as low as 9.1¢/kWh. LCOE could be further reduced by applying carbon emissions offsets or other market or policy incentives. While LCOE is, as expected, highly sensitive to utilization rate and market pricing for both arbitrage and ancillary services such as balancing, other factors such as well workover costs and service lifetime of the individual wells can affect LCOE significantly.

Should intermittent renewables development continue to grow over the coming century, the need for balancing options will likely grow as well. As society moves toward a lower-carbon energy mix, zero-emissions technologies such as geothermal-coupled CAES could offer an increasingly competitive option to offset the use of peaking gas generation, which currently supplies a large amount of balancing in the U.S., but which is associated with relatively high CO_2 emissions intensity. However, additional work is needed to validate the results of this paper study to confirm that existing well completions can be repurposed for compressed air storage at costs that support their economic feasibility. Also, partnering with a utility to refine assumptions about long-term market pricing for arbitrage and ancillary services would be extremely helpful to understanding the nameplate capacities that would be most attractive to investors in the near-, mid- and long-term.

[1] sLCOE calculated based on gross capacity of 15.4 MW, 35 wells, and 17% capacity factor, or 4 hours of power generation per day coincident with peak demand.
[2] Using scaled exponents for material and manpower at 0.75, piping and surface improvements at 0.85, well refurbishment at 1.0, and 57% combined indirects.

Acronyms and Abbreviations

API	American Petroleum Institute
CAES	compressed air energy storage
CAISO	California Independent System Operator
FERC	Federal Energy Regulatory Commission
GT	geothermal
GT-CAES	geothermal-coupled compressed air energy storage
ID	inside diameter
kWh	kilowatt-hour
LCOE	levelized cost of electricity
MWh	megawatt-hour
MYIP	minimum internal yield pressure
OD	outside diameter
UNOCAL	Union Oil Company of California
PG&E	Pacific Gas and Electric
psia	pounds per square inch absolute
psig	pounds per square in gauge
sLCOE	simplified levelized cost of electricity

Contents

Figures

Tables

1.0 Introduction

1.1 Objectives

The present study continues Pacific Northwest National Laboratory's research on the application of geothermal (GT) energy to compressed air energy storage (CAES) configurations. Expanding on prior analysis where sedimentary formations and salt domes were modeled for the CAES elements of various systems, this year's work has focused on revising wells for use as pressure vessels for compressed air storage. The primary objectives of this paper study are to examine feasibility of this novel technological application, to develop estimates of project sizing and associated resource requirements, and to examine overall capital costs and levelized electricity costs via case study analysis.

1.2 Background

Previous work by McGrail et al. (2013, 2015) examined options for geothermal-coupled-CAES (GT-CAES) to provide grid-scale balancing resources for zero-emissions integration of intermittent resources such as wind. While those studies indicated that GT-CAES may be both technically achievable and economically feasible, the authors note significant barriers to identifying sites that offer both a suitable CAES reservoir—particularly anticlinal structures in suitably thick, porous and permeable sedimentary rocks—and a promising geothermal resource at the same location. Still, the appeal of large-scale energy storage that can leverage reliable renewable resources to balance the more intermittent renewables, while maintaining the stability of the electric transmission grid using non-emitting technology, suggests that this approach could be broadly applicable were there a way to ease the siting constraints. In addition to larger-scale storage options offered by technologies like pumped hydroelectric and thermal storage, current commercially available energy storage options include large steel tanks to store compressed air or other fluids, suggesting that the CAES portion of the project could be accomplished via relatively low-tech means, allowing for a narrower focus on the GT resource and the market need for energy storage.

While purpose-built pressure vessels are practical for small, facility-scale energy storage, they reflect a significant capital cost. Instead, billions of tons of steel well casing exist under the ground across large swaths of the United States, including in areas that offer proven geothermal resources. The steel casings in millions of abandoned wellbores in the U.S. and elsewhere may offer an opportunity to create subsurface pressure vessels for CAES, leveraging disused capital assets left over from conventional energy production to enable development of both geothermal and intermittent renewable resources. This approach, relative to the use of sedimentary reservoirs evaluated under previous studies (McGrail 2013, 2015), also offers the benefit of limiting the pressure effects to the well itself, with only minor near-field effects in the rock matrix expected as a result of physical changes at the casing/cement/rock interfaces. As a result, the geographic applicability should be significantly broader than that of GT-coupled sedimentary CAES, making more geologically complex locations in California, Texas, and the Gulf Coast amenable to this hybrid energy storage application.

The vast number of existing wellbores in the U.S. also reflects a rich dataset to underpin assessments of the CAES part of the project. Whereas previous efforts required the use of sparse data to identify and parameterize modeling assumptions for potential CAES reservoirs—often intervals of little interest to drillers and thus poorly characterized in publicly available well logs and other materials—regulatory requirements for well completion reporting, and the relatively wide availability of these data, results in a much higher degree of certainty regarding site-specific conditions to inform simulation assumptions. In addition to the enormous value of the existing data, the wells themselves represent a considerable stock of stranded capital. While many wells have already been plugged and abandoned, many others are approaching their required closure dates, should production not resume in the interim. Leveraging this infrastructure for energy storage during periods of low commodity prices that make the wells uneconomical to produce could preserve the wells for future use, should CAES wells be revised for reversibility. For wells that will not be produced again, more permanent revision options could allow field operators to derive additional value from sunk and heavily depreciated capital.

1.3 Hybrid GT-CAES

Conventional CAES projects use stored air to increase efficiency in a natural-gas-fired power cycle by preheating the compressed air with gas and introducing it directly into the expansion (power) turbine. Previous evaluations have considered both natural-gas-based CAES facilities and geothermally driven configurations using subsurface reservoirs for compressed air storage (McGrail et al., 2015). Due to the difficulty of finding both a geothermal resource and a thick, permeable subsurface storage reservoir with high porosity and some degree of structural closure consistent with the configuration(s) evaluated for reservoir-based storage, this study considers using abandoned or existing, low-production geothermal wells that, when repurposed, could act as subsurface pressure vessels, replacing the need to find acceptable sedimentary-based subsurface CAES reservoirs evaluated in previous projects.

The hybrid GT-CAES unit proposed could be developed and operated as a standalone unit or in complement to established steam-based power production facilities by adding unit processes for air compression, heat exchange, a backpressure steam turbine, a three-stage expansion turbine, ancillary piping, and geothermal well repurposing/refurbishment requirements. For design and costing purposes, the only substantive difference between the two (standalone vs. complementary) is a modest backpressue turbine (~520 kW), and the components (ancillary piping, instrumentation, controls, etc.) associated with that unit. For completeness, both operational configurations are addressed, captured as the functional difference between gross and net capacities and energy.

As visualized, during “off-peak” hours, excess or low-cost power from the grid would be used to operate a centrifugal air compressor filling repurposed geothermal well casings to an acceptable storage pressure. During peak hours, extraction steam from an existing geothermal well or from an existing steam turbine would be used to reheat compressed air recovered from the repurposed well casings, and expanded across a three-stage expansion turbine.

Though the hybrid GT-CAES unit would parasitize the existing steam turbine, due to energy supplied by the compressed air and the modest reheat steam requirements, the power output of the combined system would have a net increase of 13.4 MW as modeled, taking the traditional Rankine cycle steam system to a round trip efficiency well over 50%, contingent on the amount of extraction steam consumed. The conceptual system is illustrated in the following block flow diagram (Figure 1.1), which includes basic unit operations, process flow(s), and storage reservoirs for the compressed air and geothermal resources.

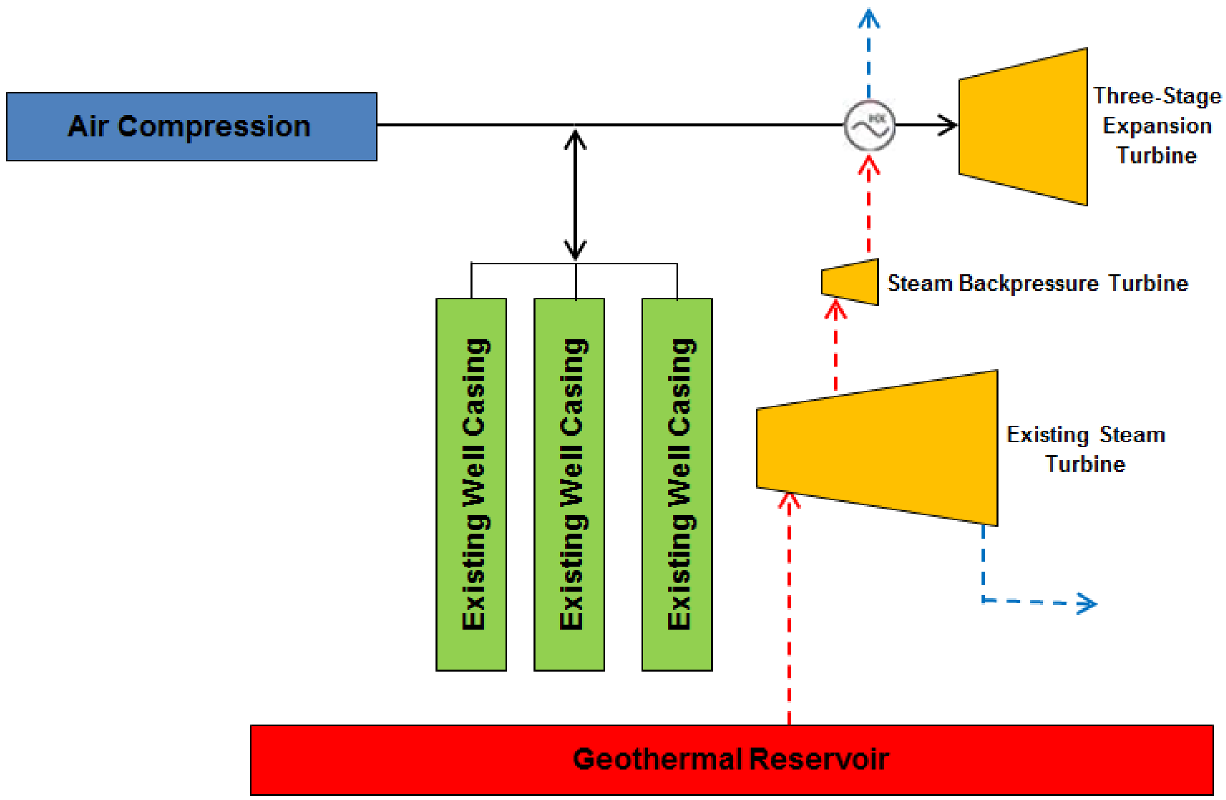

Figure 1.1. Hybrid CAES Coupled Geothermal Power Production Facility

By coupling the well-based CAES component to the existing geothermal-based steam power production facility, the unit could be dispatched as a zero-emissions power production facility for basic energy production, grid balancing and reserve services, and arbitrage, offering a grid-scale solution that will be increasingly attractive in a carbon-constrained future.

2.0 Site Discussion

2.1 Site Selection

Because the purpose of the current study is to focus on the technical and economic feasibility of integrating geothermal energy with well-based storage of compressed air, sites considered for analysis were those with a significant amount of available data on both the geothermal resource and the existing well infrastructure at the field. Additional consideration was given to conditions that might suggest current or future markets for energy storage in the region.

To perform an initial screening of site options, productive well density data was mapped against national geothermal resource estimates to identify areas of highest interest (Figure 2.1).

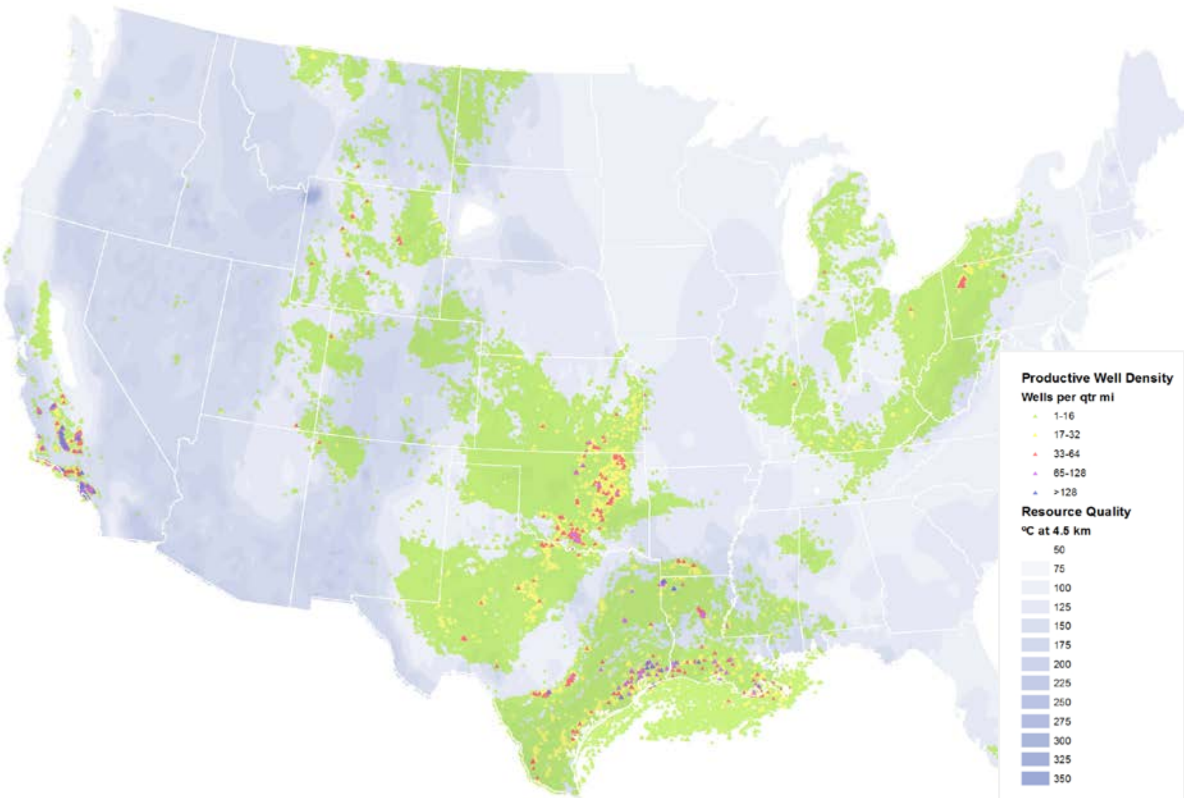

Figure 2.1. Density of Productive Wells (per quarter-mile) Relative to Generalized Geothermal Resource Potential (°C at 4.5 km)

As in earlier studies, both California and the Gulf Coast appear to be of greatest interest, not only in terms of their geothermal resources, but also because both regions have seen marked increases in renewable energy development, suggesting future market potential for large-scale energy storage. However, the opportunity to use wellbores for compressed air storage, rather than seeking suitable sedimentary reservoirs, allows a broader range of siting options. In particular, the use of wellbores for CAES could help overcome technical and permitting hurdles that largely precluded the examination of sedimentary CAES in California. In particular, because pressure excursions are limited to the wellbore itself—defined here as the casing(s) and cement, as well as near-field effects associated with changes at the casing/cement and cement/rock interfaces—there is little chance of far-field pressure effects that drive much of the risk in subsurface storage operations. If well containment were confirmed and maintained, this approach may be suitable for areas where injection pressure limitations would otherwise make reservoir-based CAES untenable.

An initial examination of the match between existing wellbore density and known geothermal resources evaluated siting options in Southern California (Figure 2.6) and Northern California (Figure 2.3).

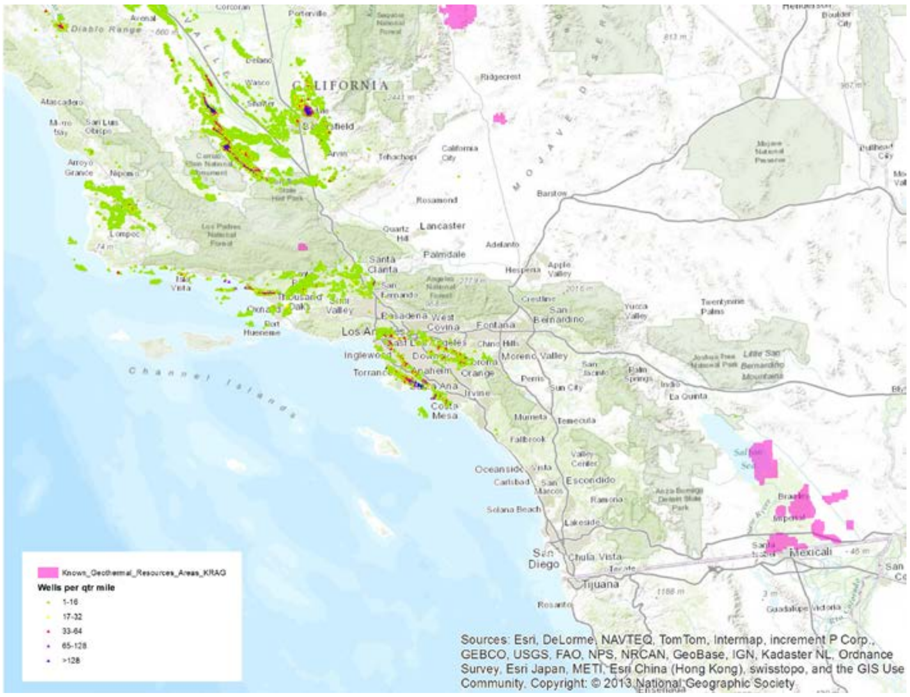

Figure 2.2. Existing Well Density and Areas of Known Geothermal Resources, Southern California

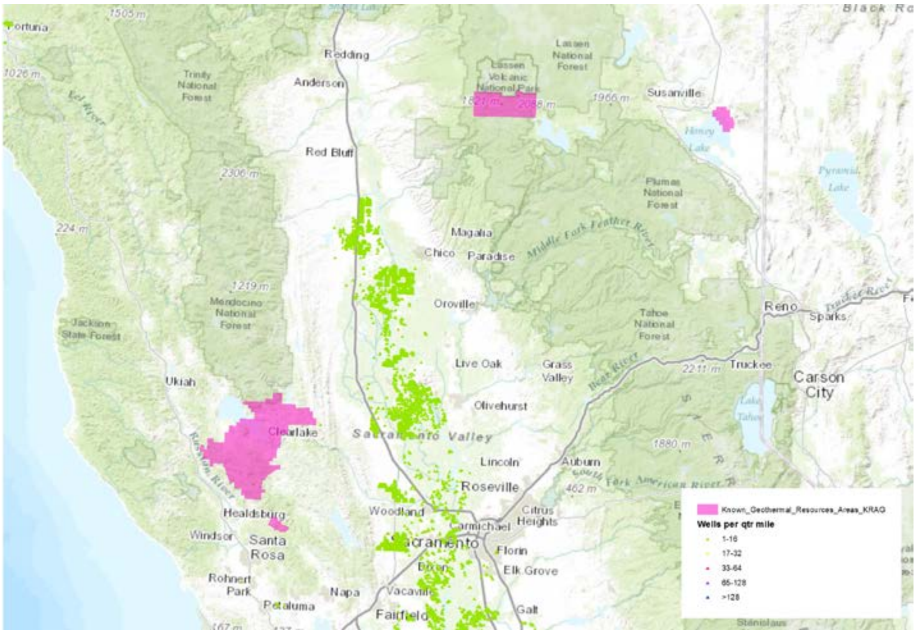

Figure 2.3. Existing Well Density and Known Geothermal Resource Areas, Northern California

While Southern California is home to known geothermal resources as well as vast numbers of existing oil and gas wells, there is typically a poor overlap between the Known Geothermal Resource Areas (KGRA) data used to inform early siting efforts in this study. Though this does not preclude the existence of good geothermal resources in areas with existing wellbores beyond the geothermal resource areas given in the KGRA dataset, given the intent of this project to examine the feasibility of this hybrid approach, the authors elected to focus on sites present in the KGRA to ensure that sufficient data existed in the areas selected for both the geothermal resource and existing wellbores. The Sespe Hot Springs, located in the Topatopa Mountains in Ventura County, were evaluated further because of the presence of known oil development wells to the southeast of the springs. However, on further investigation, these wells appeared to be quite old (Figure 2.4), possibly predating modern well construction standards, and the resource at the springs were poorly characterized.

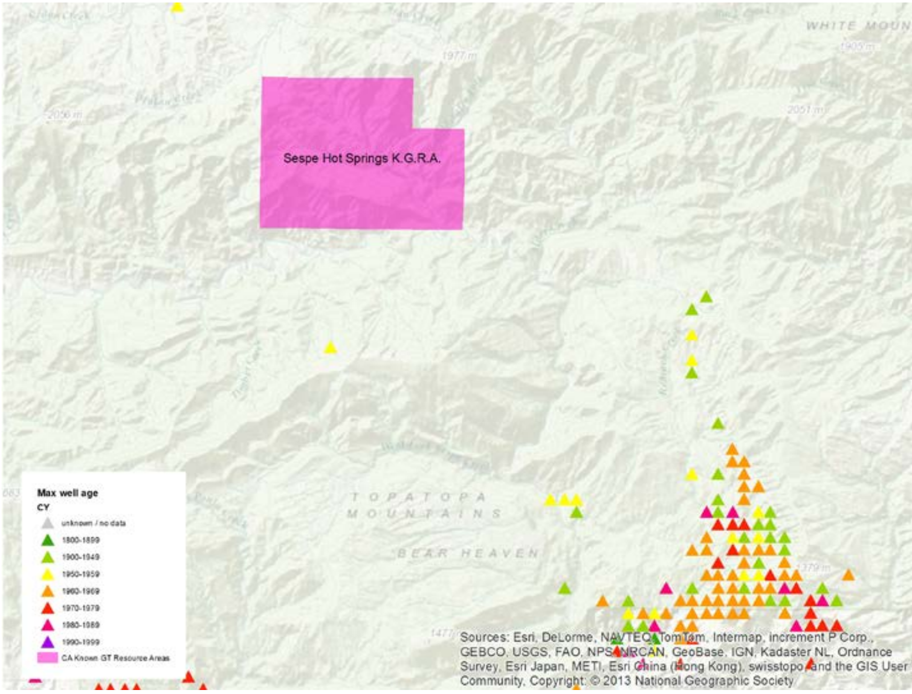

Figure 2.4. Sespe Hot Springs Geothermal Resource Area, and Proximal Oil and Gas Wells, by Age

For this first-order economic analysis, The Geysers geothermal field was selected for case study. The Geysers field, which has been under commercial development for over 60 years, offers a wealth of data on geothermal production and existing wellbores of interest for CAES (Figure 2.5). Additionally, The Geysers field is located near California's Bay Area, one of the largest load centers on the West Coast, and a possible future market for zero-emissions energy storage. Currently, producing geothermal fields like The Geysers may also offer the opportunity to use marginal wells being phased out of production, either as geothermal sources for the hybrid energy storage projects or via conversion for air storage.

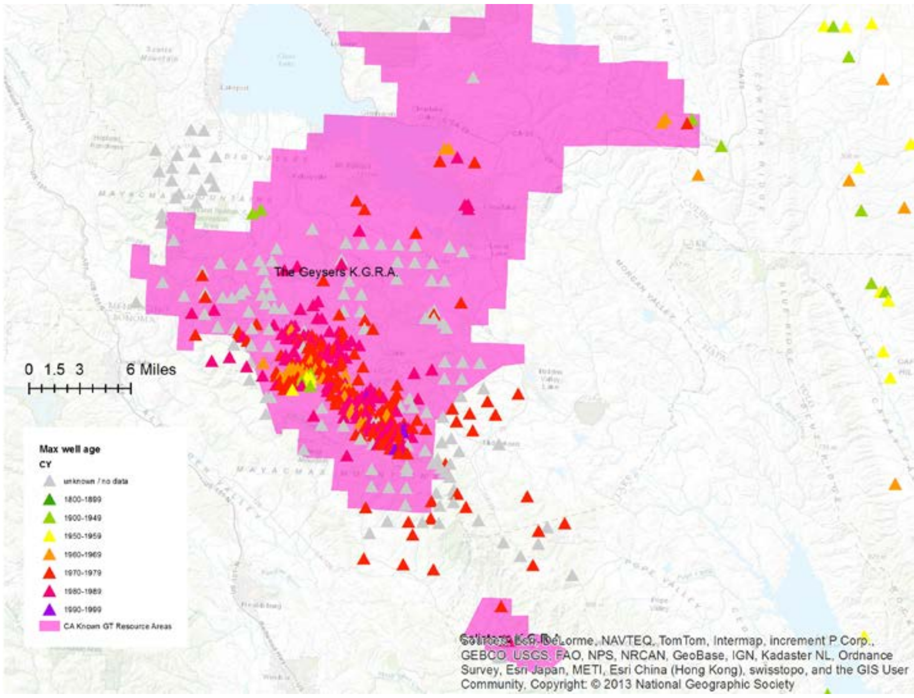

Figure 2.5. The Geysers Geothermal Resource Area, and Proximal Wells, by Age

2.1 Geologic Setting

The Geysers geothermal field is a vapor-dominated reservoir system that evolved from a deep magmatic heat source that continues to charge the overlying fractured, otherwise impermeable metamorphic rocks with high-temperature steam (Donnelly-Nolan et al., 1993). The productive portion of the steam field covers a large area of approximately 30 mi^2 along the southwest edge of the Quaternary Clear Lake volcanic field, and is bounded by major right lateral strike-slip faults related to the San Andreas transform fault system (Elkibbi and Rial, 2005, McLaughlin and Donnelly-Nolan, 1981).

The near-surface geology of The Geysers field consists of Clear Lake volcanics and metamorphosed marine sedimentary and igneous rocks belonging to the Franciscan complex (Donnelly-Nolan et al., 1993). The deeper reservoir rock consists of fractured metagreywacke sandstone that overlies an intrusive felsite complex (Donnelly-Nolan et al., 1993). Episodic Pleistocene movement of the underlying felsite intrusion is thought to have led to the development of the highly permeable fracture network that makes up the productive reservoir (Truesdell et al., 1993). The non-fractured reservoir rock by itself is known to have very low porosities (1% to 5%) (DiPippo, 2012). However, extremely high production rates are observed in wells that penetrate intensely fractured regions.

The architecture of the fractured reservoir has been well defined over the years by the several hundred wells that have penetrated the steam field (Figure 2.6). Structure and isopach mapping of the productive reservoir intervals show considerable relief and ranges in thickness (DiPippo, 2012). The reservoir thickness in the northwest portion of the field ranges from 600 to 100 m thick, with the first steam entries occurring at elevations between 760 and 1,370 m below sea level. However, the thickness increases to 1,500 m and even 5,000 m in the central and south-east areas, where the steam entries are much shallower, around 610 to 760 m below sea level.

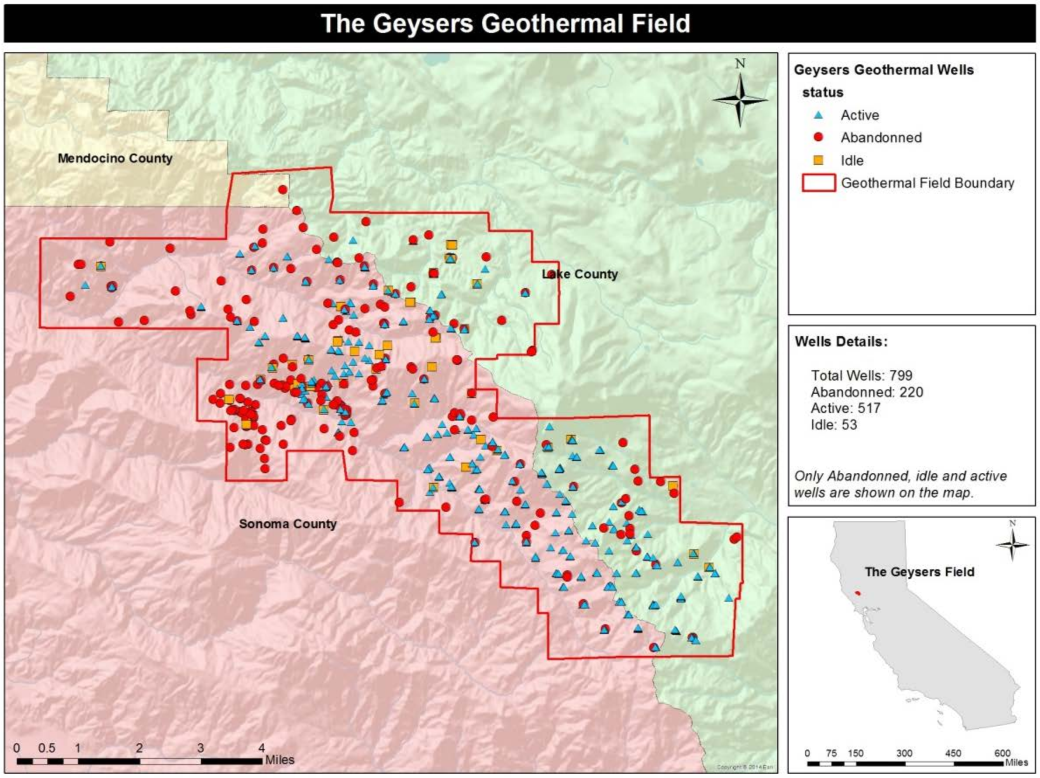

Figure 2.6. Map of The Geysers Geothermal Well Field

2.2 Geysers Development History

The history of The Geysers geothermal field as presented by Hodgson (2010) includes a progression through 5 eras of evolution, from early Native discovery to modern day commercial power generation. Surface manifestations of the thermal anomaly in The Geysers area, such as fumaroles and hot springs, were initially used by Native Americans for domestic and health-related benefits. These same features drew significant attention from early developers looking for ways to exploit the vast resource. The earliest development began in the 1850s with the construction of a resort hotel. However, electrical power generation from natural steam at The Geysers was not considered seriously until the 1920s. The first geothermal wells were drilled in 1921, and private power production was developed to support The Geysers Resort. Eight additional wells were drilled and tested between 1922 and 1925. Although well tests indicated sufficient deliverability to support small-scale power production, commercial development was not pursed for more than a couple decades.

In the mid 1950s, a new drilling program was initiated, and by 1960 Pacific Gas and Electricity (PG&E) Utility had developed the infrastructure to support the first commercial electrical power generation at The Geysers. By the early 1970s, a partnership between PG&E and the Union Oil Company of California (UNOCAL) marked a period of growth in development activity. Twelve power plants were installed over the next 10 years. However, by the late 1990s, declining reservoir pressures from overproduction led to a dramatic decline in power generation (Sanyal and Enedy, 2011). In recent years, declining reservoir pressures have been curtailed and power production rates have been stabilized by adopting sustainable pressure management practices (Sanyal and Enedy, 2011). Large volumes of effluent are now piped from nearby municipal wastewater treatment facilities and injected at The Geysers field, effectively maintaining reservoir steam pressures for a long future of sustainable power generation (Sanyal and Enedy, 2011).

3.0 Utilizing Wells for Compressed Air Storage

To assess the degree to which steel well casing could be used for compressed air storage, and the pressures and mass flow rates associated with such an approach, a generalized analysis of several representative casing grades was undertaken. This enabled the development of assumptions regarding the number of repurposed wells that would be required to support auxiliary power generation from a single geothermal production well, assuming the casing grades would be predominant in the well field.

3.1 Capacity and Scalability of Well-Based CAES

The preliminary analysis of steel casing grades was used to determine the number of repurposed wells required for air storage to provide a project of meaningful size. There are hundreds of combinations of steel grade, thickness, and diameter casing available from manufacturers. Because the goal of this effort was to better understand the range of storage capacities associated with the range of casing types most likely to be encountered in existing, developed fields, a lower- and higher-grade steel (J-55 and P-110, respectively) were selected to evaluate the impact of casing grade on maximum allowable air pressure for storage, total air mass per well, total compressor power consumption, and potential mass flow rate impacts on extraction turbine operations.

Two cases were modeled (Figure 3.1) assuming a total casing depth of 5,000 ft using American Petroleum Institute (API) specifications for 7-inch (OD) casing for J-55 (6.46-inch ID); and P-110 (5.82-inch ID) steel grades, and performance properties (API 1982). Considering only the material strength of the single casing, and neglecting containment provided by additional cement, larger-diameter outer casing(s) or the host rock itself, J-55 casing can support pressures of up to 3,740 psig at the wellhead; the P-110 casing increases more than four-fold to 16,225 psig at the wellhead.

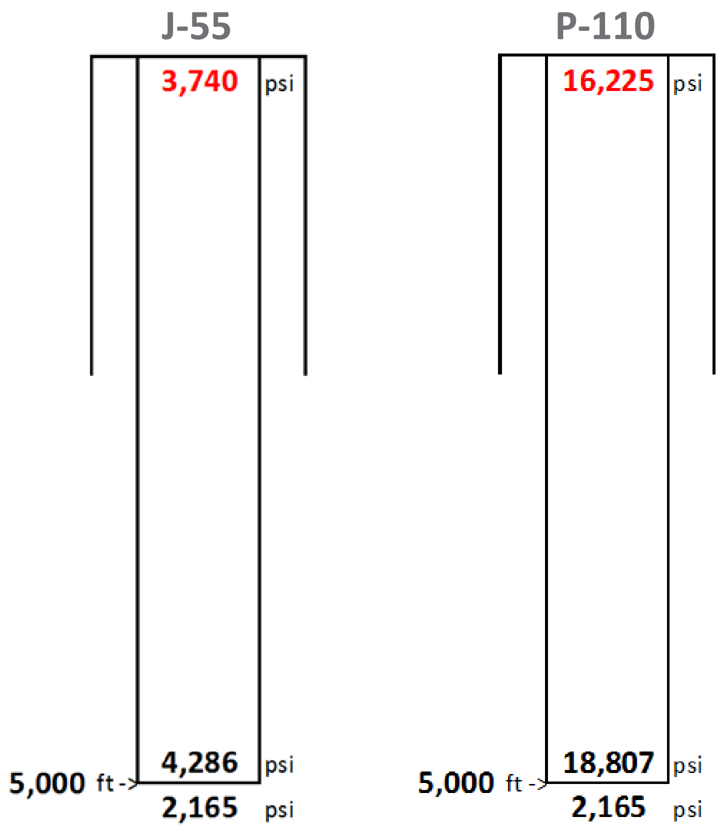

Figure 3.1. Preliminary Wellbore Configurations Assessed for Capacity Scaling and Site Screening

Based on the storage pressure, air injection simulations were completed for both casing grades, assuming a 12-hour off-peak compression period and holding the wellhead pressure limit at the minimum internal yield pressure (MIYP). Initial modeling used a multi-stage centrifugal compressor, compressing ambient air up to the MIYP for each respective casing grade, and evaluated the energetics required for compression. Based on these bounding parameters, a single well with J-55 casing could store a total of approximately 9,000 kg of compressed air consuming about 1,700 kWh. The higher grade P-110 (41#/ft) could store approximately 30,000 kg of compressed air, and was modeled to consume about 4,000 kWh.

The capacity assessment discussed above suggests higher-grade casing strings might be preferable if repurposing for compressed air storage. Though both casing grades evaluated could provide significant capacity and energy, developed fields with a significant number of wells per square mile could readily accommodate a range of hybrid GT-CAES projects even with the more common, lower-grade casing.

Where only a few wells are available locally, this application might lend itself to site-level storage when coupled with a relatively small slipstream of geothermal fluid. For the purposes of modeling grid-scale storage, these initial single-well simulations were used to define the range of wells needed to provide at least a 10-MW storage facility (considered to represent commercially significant capacity), and to inform siting decisions for the case study presented below.

3.2 Existing Well Completions

The extensive development of The Geysers field has led to the drilling and production of several hundred wells, offering an extremely dense population of well data. A statistical summary of The Geysers geothermal field provided by Calpine Corporation, a leading power plant operator of The Geysers field, reports an average well depth of 8,500 ft with average steam production rates of 36,180 pounds per hour and an average reservoir steam temperature of 371.4 °F (189 °C) (Calpine, 2015).

Historical casing selections for wells completed at The Geysers field have been driven by the need to supply sufficient steam production to ensure a commercially viable well. As such, large diameter production holes were selected to accommodate high flow rates with minimal friction loss. Other casing design considerations at The Geysers include cementing strategies, cement properties, and casing grade. Because the well completion depths at The Geysers are relatively shallow compared to deep oil and gas wells, the collapse strength required to withstand annular pressures while placing cement is relatively low, enabling the use of lower grade (K or N) casings (Pye and Hamblin 1991).

A typical production well drilled at The Geysers field is generally constructed with casing installed to the top of the productive zone, with open-hole completions extending into the reservoir. The diameters of the production casing and open hole are generally maximized to the extent possible; however, the drilling depth to the top of the productive zone imposes a practical limit on the diameter of the borehole at depth. The depth to the productive zone varies considerably across The Geysers field, resulting in various well completion designs. For example, wells located in the southeast portion of The Geysers field are relatively shallow and are generally completed with 13-3/8 inch (K-55; 54#/ft) production casing to a depth between 3,000 to 4,000 ft (Henneberger et al., 1995, Henneberger et al., 1993). In the northwest portion of The Geysers field, production wells are generally much deeper and constructed with 9-5/8 inch (K-55; 36#/ft or 40#/ft) production casing extending to approximately 8,500 ft. With deeper well completions, the 9-5/8 inch production liners may or may not extend to the surface. For repurposing a well for CAES, a tie back liner that extends the surface would minimize the total storage volume of the well, but would offer more casing integrity and reduce the risk of casing fatigue and failure when subjected to frequent pressure and thermal loading cycles.

ASPEN® scenarios were developed to reflect conservative assumptions regarding well capacity, and modeling has been performed for wells completed with 9-5/8 inch (K-55; 36#/ft or 40#/ft) production casing cemented in place from the surface to a plugged-back depth of 8,500 ft.

4.0 System Design and Unit Operations

The overall objective of the wellbore and plant simulations was to model and calculate a representative design and cost basis for augmenting a geothermally derived Rankine cycle, using compressed air that could be stored at pressure in abandoned or repurposed wells. At a summary level, the usefulness of augmenting the power production cycle affords greater operating flexibility by being capable of supporting potential value streams for both consumption and production of power and energy.

Routine operation of the facility assumed that grid supplied energy would be available for the compression cycle. Depending on location, the energy could be derived from excess capacity and/or lower value energy as might be coincident with off-peak hours. During the power generation cycle, compressed air would be extracted from the wellfield and expanded and reheated twice in an expansion turbine using extraction steam from an existing steam turbine.

Process modeling was performed to evaluate the potential for load (air compression cycle) and power production (compressed air extraction cycle) that could be expected during operation of the GT-CAES facility. For the purposes of system design, compression was assumed to take place over a 12-hour off-peak cycle, with expansion and power generation occurring over a 4-hour peak period. The simulations and accompanying heat and material balances were developed using ASPEN, and the overnight total project cost estimates were developed using ASPEN Process Economic Analyzer (ASPEN IPE®, v. 8.4) which provides costs in 2013 dollars.

4.1 CAES Wellbore Design Basis

Mass flow, total mass, and compression requirements were estimated consistent with the methodology described in Section 3.1, using a common completion of 9-5/8 inch K-55 production casing cemented in place from the surface to a plugged-back depth of 8,500 ft (Figure 4.1).

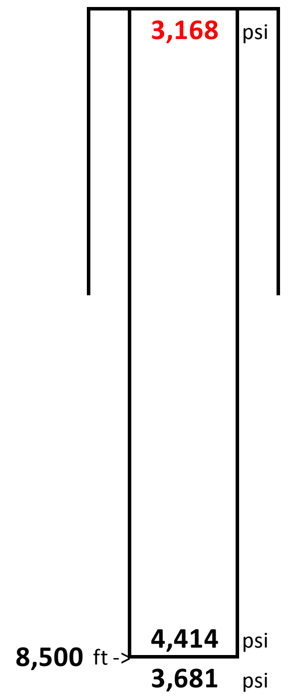

Figure 4.1. 9-5/8 Wellbore Configuration for Air Storage and Pressure Calculations

With the wellhead pressure limited to 90% of calculated MIYP (3,168 psia), a single 9-5/8 wellbore was calculated to have the following characteristics (Table 4.1).

Table 4.1. Compression Requirements Per Wellbore

Pressure (bar)	kW	Pipe Inverse (kg)	Time Elapsed per Compression Period (hr)	Total Time (hr)	Total Energy (kWh)
47	202.44	5,150.4	0	0	0
64.15	215.50	6,897.5	1.35	1.35	282.44
81.3	225.76	8,596.0	1.31	2.67	289.91
98.45	234.26	10,248.9	1.28	3.94	294.12
115.6	241.55	11,858.1	1.24	5.19	296.16
132.75	247.95	13,424.8	1.21	6.40	296.64
149.9	253.67	14,950.3	1.18	7.58	295.97
167.05	258.85	16,435.5	1.15	8.73	294.43
184.2	263.52	17,882.6	1.12	9.85	292.38
201.35	267.91	19,291.0	1.09	10.94	289.52
218.5	272.00	20,662.3	1.06	12.00	286.37
TOTAL	**Avg. 244 kW**			**12 hr**	**2,917.95**

A single wellbore compressing from 47 bar to 219 bar over a 12-hour period could store up to 20,660 kg of compressed air, requiring an average of 244 kW over the 12-hour period, consuming a total of 2,918 kWh.

4.2 Air Compression and Wellfield Utilization

To arrive at an appropriate number of CAES wells that could be supported by a single geothermal well, an iterative analysis was completed starting with the baseline geothermal well characteristics as described in Section 3.2 (16,411 kg/hr steam), coupled with the single CAES wellbore analysis. The governing premise was to add CAES wells (and accompanying mass flow) to the simulation until essentially all of the steam had been consumed in the reheat stages.

This required setting up an initial simulation (Figure 4.2) to determine the duty required by the re-heat exchangers between the first and second expansion turbines, as well as the second and third expansion turbines, and simulating expander output (kW). Extracting from a single CAES well at a rate of approximately 3,960 kg/hr per well for a period of 4 hours, this single well configuration indicated that 239 kg/hr of steam would be consumed in the first reheat (FHTR1 going to HTR1), while the second reheat (FRHT1 going to RHT1) would consume 223 kg/hr of steam, leaving approximately 16,000 kg/hr steam available for consumption. Having met the heat exchanger duties, the excess steam, highlighted as the RHTSTM flow stream in the Figure 4.2 (“To other air wells”), was simulated to be available for additional air heating.

A single geothermal well, with a steam rate of 16,411 kg/hr, is estimated to support up to 30 to 35 CAES wells via preheating of air prior to each expansion stage. Modeling included efforts to improve the round trip efficiency, including refinements to steam utilization, and mass flow of air to maximize power output within the mechanical limits of the machinery and proposed well completions. As noted in Table 4.1, this also assumed that a modest amount of air would remain in the wellbore at all times. With the remaining air mass in the well at 47 bar (equivalent to 5,150 kg air), the working gas volume was simulated at 15,500 kg per wellbore, or 512,000 kg total for compressed air that could be used in the expansion (generation) mode.

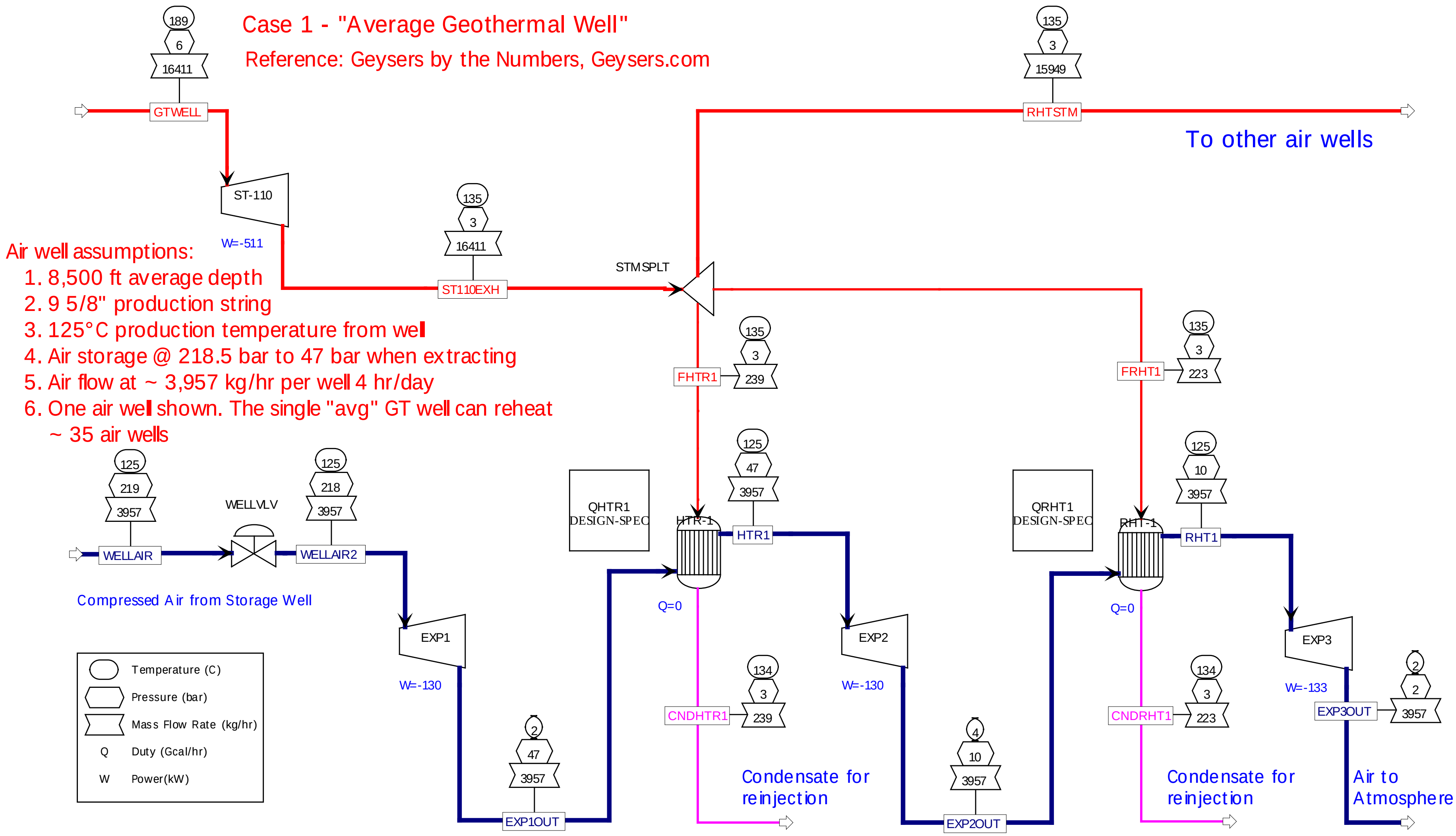

Figure 4.2. GT-CAES Single CAES Wellbore Recovery and Power Generation Simulation

4.3 Compression Process Flow and Heat – Material Balance

Having established the likely number of CAES wells that could be used by a single geothermal producing well, the simulation was adjusted to account for compressor sizing and piping required to fill the 35 CAES wells over a 12-hour period.

Relative to the design basis described in Section 4.1, minor modifications to the simulation resulted in slight decrease in compressor average power consumption of approximately 2 kW. During the compression stage, the 8-stage intercooled centrifugal compressor, operating at a normalized average of 242 kW over the time duration, was simulated to fill a single well with a flow rate of 1,312 kg/hr (AMBAIR) compressing ambient air (1 bar, 25°C, and 60% relative humidity) to 219 bar.

With the compressor modeled at 80% polytropic and 98% mechanical efficiency, a multiplier was used to then size the unit for a 35-well CAES system. With a combined total flow of 45,918 kg/sec, the compressor (C-110) would deliver 45,243 kg/hr of compressed air (CMPDIS) to the 35 wells over a 12-hour period, consuming a total of approximately 102,000 kWh. Compressor condensate (CMPH2O) at 674 kg/hr could be reinjected, or as a relatively high purity water stream, could be used to offset site water needs as applicable.

The compressed air is distributed at 124°C to the wellhead. Because this simulation work evaluated diurnal operations of the CAES unit, it was assumed that injected air would retain remaining heat of compression, thereby reducing the heat required when recovered and utilized in the power generation mode. The configuration is shown in Figure 4.3, followed by the heat and material balance in Table 4.2.

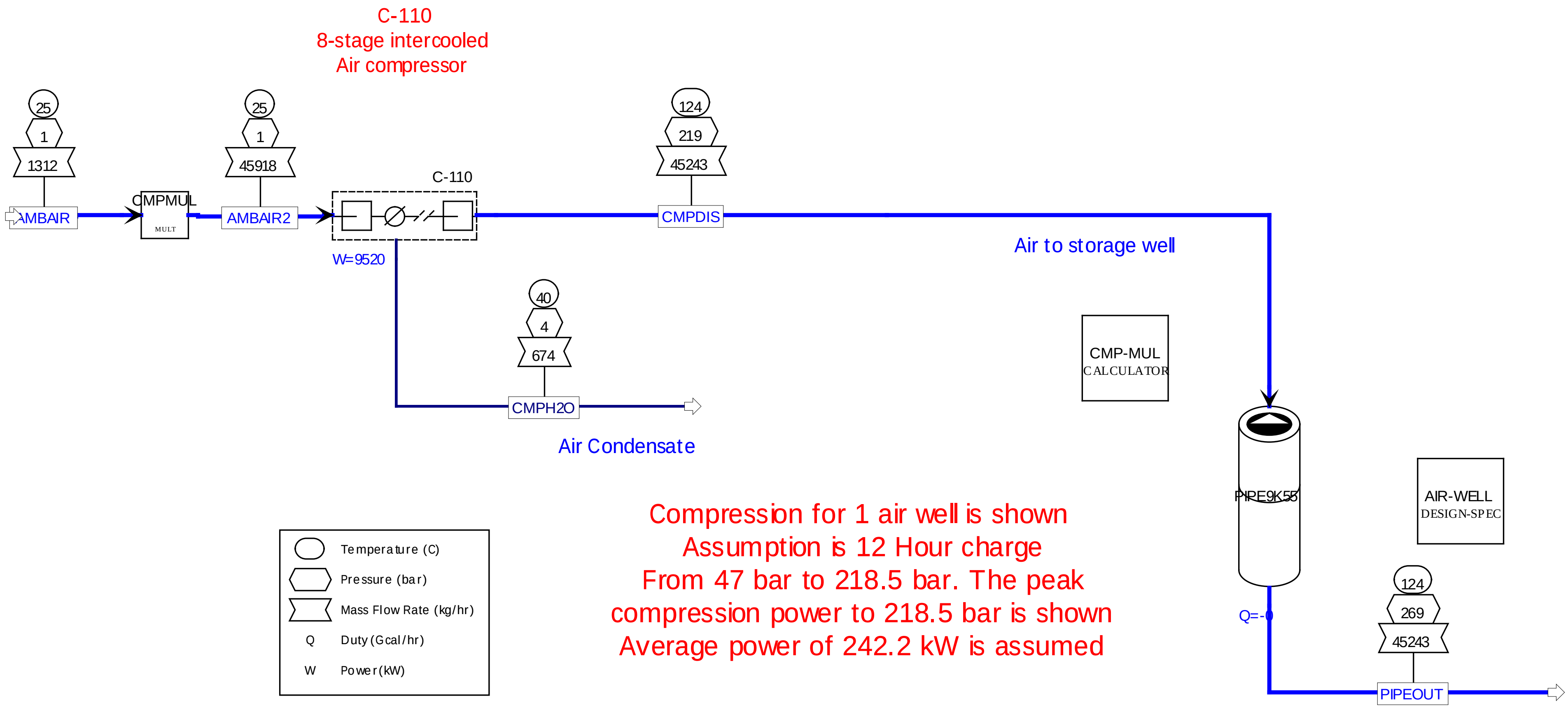

Figure 4.3. GT-CAES 35 Well Compression Simulation

Table 4.2. Air Compression Material Balance for 35 CAES Wells

Stream Number	AMBAIR	AMBAIR2	CMPDIS	CMPH2O
Stream Description	Ambient Air Supply for a Single Well	Total Ambient Air Flow	Compressor Discharge	Compressor Condensate
Temperature (°C)	25	25	124	40
Pressure (bar)	1	1	219	4
Mass Flow (kg/hr)	1,312	45,918	45,243	674

5.0 GT-CAES Air Recovery and Power Generation

During the power generation phase of the GT-CAES cycle, produced air is expanded for 4 hours per day in three stages of expansion, with geothermally derived steam providing reheating between each stage. As envisioned, the GT-CAES plant could be deployed to supplement an existing steam-based geothermal power plant to increase operating flexibility, or could be constructed and operated as a standalone unit. The following simulation proposes a standalone configuration which would directly access an available geothermal steam supply and use a backpressure turbine to meet process pressure and temperature requirements. In the event that extraction steam from an existing steam turbine is available at the temperature, pressure and rate needed, the only difference between these two configurations is the use of a backpressure turbine and the associated costs.

5.1 Power Generation Process Flow and Heat – Material Balance

Recovery of compressed air is assumed to take place continuously over a 4-hour power generation cycle. Similar to the air compression and injection simulation, the model assumed compressed air recovery from a single well at 3,878 kg/hr, and extrapolated to extract from 35 wells. Polytropic efficiency of 85% and mechanical efficiency of 98% are assumed for all expanders.[1] Expansion pressures are governed to maintain expander discharge temperatures above freezing, except the final expansion, which is discharged to atmosphere.

Starting with the geothermally derived steam supply (GTWELL), 16,411 kg/hr of 189°C steam at 6 bar would supply a modest backpressure turbine (ST-110), recovering 511 kW. Discharge from the backpressure turbine at 135°C, 3 bar, and 16,411 kg/hr would split and supply two compressed air reheaters. HTR-1 would consume 8,238 kg/sec of 135°C steam, and RHT-1 would consume 7,924 kg/hr of 135°C steam. Condensate out of both reheats is assumed to be reinjected in the subsurface.

The combined flow of compressed air at 135,729 kg/hr is recovered from the wellfield at 124°C and 218 bar (WELLAIR3). The first expansion (EXP1) takes place without reheat and yields 4,432 kW. Once expanded (EXP1OUT) at 2°C and 47 bar, the air is reheated to 125°C (HTR1), and expanded in the second stage (EXP2) yielding 4,623 kW. Expander discharge is held to above freezing temperatures, reheated again to 125°C, and expanded in the last stage, yielding 5,815 kW. The final expansion discharge temperature at -30°C is released to atmosphere. Combined, the GT-CAES plant is capable of generating 15.4 MW, consuming 2 MW of extraction steam.

As modeled, the remaining steam available for reheat (RHTSTM) is a modest 248 kg/hr. With a single reheat requiring 220 to 240 kg/hr (see Section 4.2), the remaining steam is considered unusable and is not consumed.

[1] GE Turbo-Expander Compressors; GE Oil and Gas Pamphlet.

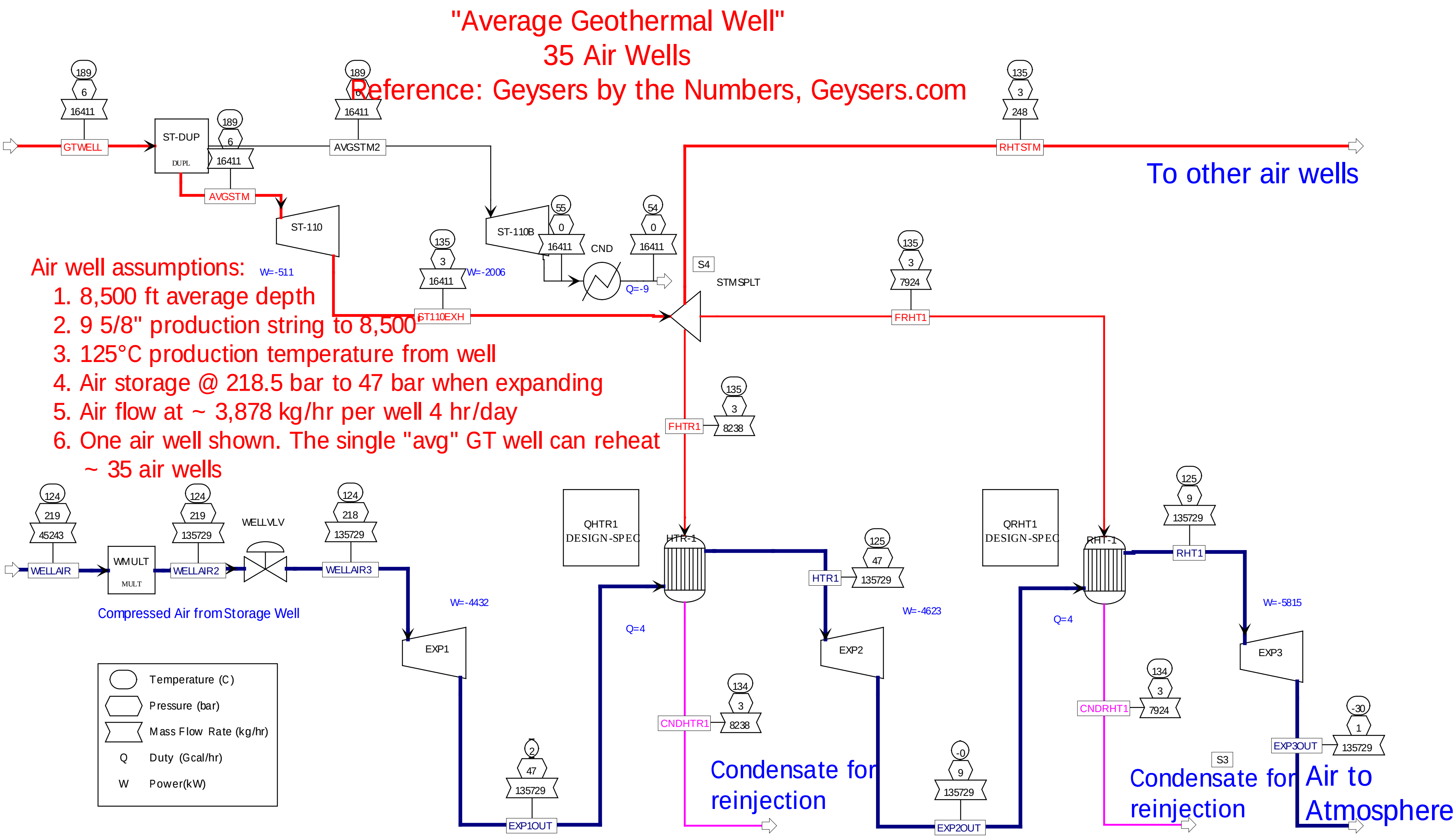

Figure 5.1. GT-CAES 35 Well Compressed Air Recovery and Power Generation Simulation

Table 5.1. GT-CAES Extraction and Power Generation Heat and Material Balance – Geothermal Resource

Geothermal - Steam Resource					
Stream Number	AVGSTM	ST1EXH	FHTR1	FRHT1	RHTSTM
Stream Description	Geothermal Steam Supply	Steam Supply after Letdown	Steam Supply to Reheat 1 (HTR-1)	Steam Supply to Reheat 2 (RHT-1)	Remaining Steam
Temperature (°C)	189	135	135	135	135
Pressure (bar)	1	3	3	3	3
Mass Flow (kg/hr)	16,411	16,411	8,283	7,924	248

Table 5.2. GT-CAES Extraction and Power Generation Heat and Material Balance – Compressed Air Resource

Compressed Air Resource						
Stream Number	WELLAIR3	EXP1OUT	HTR1	EXP2OUT	RHT1	EXP3OUT
Stream Description	Combined Compressed Air Flow from Wells	1st Expander Outlet	2nd Expander Inlet	2nd Expander Outlet	3rd Expander Inlet	3rd Expander Outlet
Temperature (°C)	124	2	125	0	125	-30
Pressure (bar)	218	47	47	9	9	1
Mass Flow (kg/hr)	135,729					

Recognizing that using extraction steam off an existing unit would necessarily penalize the system, an estimate capturing the net difference demonstrates the value of the compressed air resource. Starting with the steam specifications as used in the simulation, a fully condensing steam turbine (condensing to 2 psia or 0 bar) consuming 16,411 kg/hr of steam was modeled to produce slightly over 2 MW (ST-110B). During operation of the GT-CAES plant, extraction and consumption of steam in the reheaters would result in a commensurate loss of output from the steam turbine.

However, as shown in Figure 5.1, by incorporating a backpressure turbine at 511 kW, coupled with the first expander at 4,432 kW, the second expander at 4,623 kW, and the third expander at 5,815 kW (total of 15.4 MW), using extraction steam to reheat the compressed air contributes to a net capacity increase of 13.4 MW. This implies that, within The Geysers field, having access to geothermal steam at conditions required for reheat could make it attractive to co-locate GT-CAES with existing or future geothermal generation facilities. Tables 5.1 and 5.2 detail power generation cycle heat and material balance for the geothermal and compressed air components, respectively.

5.2 Ancillary Equipment and Unit Processes

Ancillary processes, piping requirements, and pieces of equipment that are not included in the simulations are largely limited to infrastructure, equipment, and materials needed to repurpose the well fields. Examples include surface piping, valving, controls, and power required to tie abandoned or repurposed wellheads together; access roads; buildings associated with wellfield development; and other ancillary materials.

6.0 Sensitivity Analysis

Acknowledging that any power producing facility would be subject to both operational and market based constraints, sensitivity analysis was conducted to consider and quantify applicable limitations on a GT-CAES facility relative to capacity and dispatch economics under current market conditions, to better understand how the market for this energy storage approach might evolve.

6.1 Plant Capacity and Energy

As modeled, supply pressure from the CAES wells deteriorates (if fixed at 35 total wells), causing the pressure to the first expander to decay over time. However, with the second and third expanders operating below the minimum well pressure, their respective output will remain constant even as the pressure to the first expander diminishes. The simulation was configured to determine the power vs. time curve and the average power was determined by numerical integration. The net power increase and round trip efficiency with air recovery is shown in Figure 6.1 for projects fully utilizing the geothermal resources available via 1 and 3 "average" wells (supporting 35 and 105 CAES wells, respectively). When normalized across the recovery period, these cases may offer 11.7 to 35.3 MW of capacity with round-trip efficiencies of 46%.

Table 6.1. Potential Power Decay During CAES Well Recovery

Number of Air Wells	35	105		
Condensing Steam Turbine Power	(2,006)	(6,018)	kW	During expansion this power is lost
Extraction Steam Turbine Power	522	1,534	kW	Simulation numbers
EXP1	2,764	8,469	kW	Average over the recovery period
EXP2	4,623	13,869	kW	Simulation numbers
EXP3	5,815	17,445	kW	Simulation numbers
Net Increase in Power	11,718	35,299	kW	
Expansion (Generation)	46,872,	141,196	kWh	Expansion over 4 hours daily
Compression[a] (Load)	101,724	305,172	kWh	Compression over 12 hours daily
Round Trip Efficiency	46%	46%		

(a) Calculated as the average compressor power at 242.2 kW per well, total of 35 wells or 105 wells.

6.2 Arbitrage Economics

Conceptually, the GT-CAES plant would be compressing air off-peak for approximately 12 hours per day, and extracting air during the power generation cycle for 4 hours per day (17% capacity factor). Assuming consumption of grid supplied energy (compression) always occurs during hours of low demand (for the purposes of the analysis coincident with 10 pm to 10 am), and power is generated (expansion) during the late afternoon when demand is typically highest (5 pm to 9 pm), the impact of the respective power market on plant operations and the price of power was evaluated. These intervals were selected to represent a reasonable, average range, but do not necessarily reflect "on-peak" and "off-peak" periods as defined by the California Independent System Operator (CAISO).

Pricing data were obtained for the CAISO day-ahead market, consolidated across all three trading hubs, and used to evaluate a range of operating scenarios which would function to establish economic viability.[1] For the 12-month period between October 1, 2014, and September 30, 2015, the average CAISO off-peak price was $28.68/MWh, and average on-peak price was $49.04/MWh, resulting in an average price spread of $20.37/MWh across the period of analysis. Using these simplified timing and rate assumptions, electricity purchases and sales were valued for the GT-CAES facility under baseline operations (Table 6.2).

Table 6.2. GT-CAES Baseline Operational Scenarios with CAISO Market Data (Daily Basis)

Cycle		MW	Time (hr)	MWh	Price ($/MWh)	Total Cost and Revenue ($)
Compression		8.5	12	101.8	$ 28.68	$ 2,918
Power Generation	Gross	15.4	4	61.6	$ 49.04	$ 3,020
	Net	13.4	4	53.6	$ 49.04	$ 2,628

Using average market pricing, and operating under the fixed 12-hour compression, 4-hour generation scenario, arbitrage alone generates a small amount of revenue with a price spread of $20.37 (based on gross capacity). At net capacity (after accounting for 2 MW of steam turbine loss from the associated steam host), arbitrage alone is not an economically viable option, though arbitrage becomes revenue neutral with a modest 2% capacity factor improvement (equivalent to about 30 minutes of additional generation), or at a price spread of at least $25.77.

Moving beyond the simplified fixed dispatch times toward something more closely approximating the way in which a utility might actually dispatch an energy storage resource like this, analysis of market data suggests that when operated on an hourly or daily basis, arbitrage economics improve significantly. Starting with 5-minute CAISO data, the lowest cost 12 hours in each day of the year was determined coincident with the compression cycle; as well as the highest revenue 4 hours coincident with the power generation cycle. Each daily average was then rolled up to a monthly average to dampen the price signal associated with the rarest events, and to reflect the greater uncertainty inherent in such markets.

Table 6.3 shows monthly average market prices during the periods selected for purchase (compression) and sale (expansion), evaluated as described above, as well as revenues and costs associated with the GT-CAES baseline configuration at a 17% utilization rate.

[1] CAISO day ahead market pricing for October 1, 2014 through September 30, 2015.

Table 6.3. GT-CAES Annualized Compression and Gross Generation Analysis

Month	Cycle	Cost/MWh ($)	Monthly Compression Costs and Generation Revenue ($)
January	Compression	$ 23.88	$ 75,331
	Generation	$ 69.32	$ 132,373
February	Compression	$ 13.75	$ 39,178
	Generation	$ 65.20	$ 112,457
March	Compression	$ 13.12	$ 41,388
	Generation	$ 73.88	$ 141,081
April(a)	Compression	$ 13.66	$ 41,701
	Generation	$ 69.05	$ 127,604
May	Compression	$ 6.31	$ 19,905
	Generation	$ 64.22	$ 122,635
June	Compression	$ 21.11	$ 64,445
	Generation	$ 85.06	$ 157,191
July	Compression	$ 25.13	$ 79,274
	Generation	$ 61.18	$ 116,829
August	Compression	$ 23.65	$ 74,605
	Generation	$ 67.70	$ 129,280
September	Compression	$ 24.93	$ 76,106
	Generation	$ 66.19	$ 122,319
October	Compression	$ 29.48	$ 92,996
	Generation	$ 69.65	$ 133,004
November	Compression	$ 28.25	$ 86,242
	Generation	$ 65.70	$ 121,414
December	Compression	$ 20.92	$ 65,993
	Generation	$ 65.63	$ 125,327
	Annual Compression Power Purchase Costs		**$ 757,165**
	Annual Generating Power Sales Revenue		**$ 1,541,514**

(a) April 23 through 27 had significant data gaps and were therefore not included in the analysis.

Over the course of the year, the average off-peak price of power, represented by the least costly 12-hour period in any given day, was $20.46/MWh. The average on-peak price for the highest 4-hour period in any given day was $68.57 for an annualized spread of $48.11.[1] Compared to the fixed utilization interval analysis above (see Table 6.2), the value stream associated with arbitrage is greatly enhanced by allowing the plant to operate as a flexible and readily dispatchable unit.

[1] Not restricted to 12 continuous hours of compression, nor 4 continuous hours of power generation.

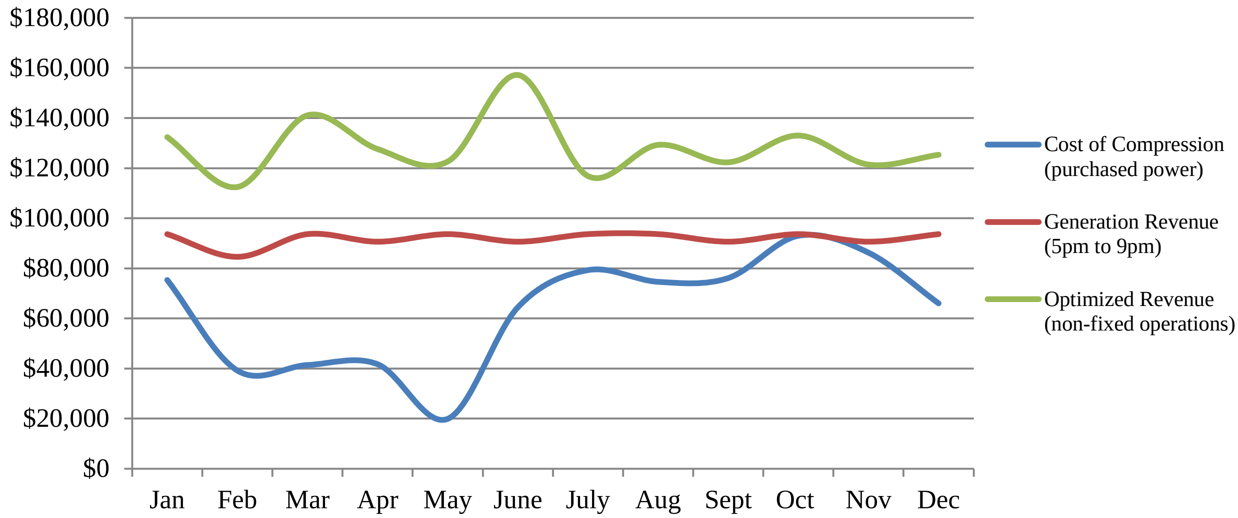

Figure 6.1. Compression and Generation Scenarios

While these two endmember cases illuminate the potential to optimize revenues on the arbitrage market, from an operations standpoint, this would inherently require a high degree of system flexibility. For example, though the unit would still optimize compression during off-peak hours, power generation operations would have to coordinate to ensure there was always adequate stored compressed air energy available for power production to capitalize on the pricing differential. Additionally, if the unit was being used to serve other purposes, such as spinning reserve or for grid stability by backing up intermittent renewable resources, plant operators would need to prioritize among multiple services based on market demand and associated pricing.

The analysis also suggests that the facility as evaluated here, even when capturing the maximum value associated with arbitrage, would be unable to demonstrate a sufficient rate of return if aligned only with that value stream. With calculated sLCOEs ranging from $0.091/kWh to $0.112/kWh, the economic viability of the GT-CAES plant must include a broader value proposition in order to meet the breakeven test for delivered cost of electricity. This would include value streams associated with operating to provide grid stability through ancillary services, the storage and utilization of excess grid-supplied renewable energy resources, and incentives associated with the production of renewable and/or low-carbon power. As policies, markets and technologies mature to address the growing need for low-carbon energy delivered to a secure, stable transmission grid, a clearer picture will emerge regarding economic incentives and market structures that will be crucial to economic viability of technologies such as this one.

Similarly, as markets respond to internal and external drivers associated with broader energy policy, increases in the market price spread could make arbitrage economics increasingly attractive. However, pricing structures that seek to incentivize grid reliability are likely to make arbitrage a backstop option for generators who have the flexibility and capacity to take advantage of price spreads when they have already captured the higher-revenue market for grid services.

7.0 Project and Levelized Costs of Electricity

For completeness, each area estimate was produced independently so that design and operational considerations could be applied where appropriate. For example, the estimate includes costs for sparing on single point of failure pieces of equipment and pumps such as the hydraulic turbine and the geothermal reinjection pump, as well as cost adders for both electrical components and instrumentation of those critical pieces. This would be an expected practice in the construction and operation of this type of facility, and is therefore included in the cost estimate.

In this manner, each area estimate was developed to account for operations and process considerations specific to that unit operation. Unit areas and the direct cost line items for material and labor are included in Table 7.1.

Table 7.1. Plant Cost Areas and Total Direct Cost Line Items

Direct Cost Areas	Direct Cost Line Items
Air Compression and Injection	Equipment and Setting
Power and Recovery	Electrical
Balance of Plant	Insulation
Well Workovers	Piping
	Civil
	Structural Steel
	Instrumentation
	Paint

In addition to area-level direct costs, project-level indirect costs were included as a percentage of direct costs. These line items included engineering, contingency, home office, freight and taxes, and contractor fees, and profit. Combined, indirect costs add 57% to the direct costs, and were uniformly applied to the combined direct cost categories geothermal wells and CAES reservoir development as well.

Table 7.2 includes direct, indirect, and total project costs for GT-CAES plant modeled, including the development costs for geothermal well workovers and other necessary balance of plant items.

Table 7.2. Total Direct and Total Project Costs for GT-CAES Plant

Area Estimate			GT-CAES 15.4 MW 1 Geothermal Well 35 CAES Wells ($M)	GT-CAES 46.2 MW 3 Geothermal Wells 105 CAES Wells ($M)
Air Compression and Injection			$ 6.6	$ 15.0
Recovery and Power Production			$ 7.7	$ 17.6
Balance of Plant [a]			$ 5.0	$ 12.4
Well Workovers [b]			$ 1.8	$ 5.3
	Total Direct Cost		$ 21.1	$ 50.3
Project Indirect Costs	Engineering	10%		
	Contingency	20%		
	Home Office	20%		
	Freight, Tax	2%		
	Fee and Profit	5%		
	Total Project Cost ($)		$ 33.1	$ 78.9
	Cost per kW ($/kW)		$ 2,151	$ 1,709
	sLCOE (cents/kWh)		$ 0.112	$ 0.091

(a) Includes provisions for site improvement, roads, buildings, well allowance, and surface piping to existing wellfield assuming an average 20-acre well spacing.
(b) Well re-entry costs ranged from $50k to $100k for the first well, and $10k to $50k for each ensuing well. Cost estimate assumes $50k per well.

Significant costs are attributed to development of the baseline plant configuration but also include estimates for balance of plant, and costs attributed to geothermal well repurposing. Within the design assumptions used to model and cost each element of the facility, the baseline 15.4-MW configuration at $2,151/kW utilizing a single geothermal production well and 35 CAES wells, compares favorably to other geothermal power production analyses; the larger 46.2 MW facility, estimated at $1,709/kW, is well below the historic average on a cost per kW basis (Shevenell 2012; EERE n.d.).[1]

By contrast to other utility scale energy storage facilities, such as pumped hydro and traditional CAES facilities, the GT-CAES plant as designed provides a cost competitive alternative. For example, pumped hydro, recently estimated at $5,300/kW, requires extensive commitments of land and resources, as well as being subject to extensive environmental regulations (EIA 2013). The GT-CAES plant as conceptualized also compares favorably to traditional CAES plants such as the McIntosh facility. Facilities such as these, when escalated to 2015 dollars, are consistent with the $/kW ranges provided above, with utility-scale projects such as these contingent on the availability of suitable subsurface storage caverns.[2]

By using available and accessible resources (existing geothermal production wells and disused wells for air storage), coupled with commercially available and proven technologies and machines, substantive improvements to both capacity and operational flexibility can be realized through an incremental capital investment.

[1] Indicates field and plant development at $2,500/kW.
[2] Information accessed at: http://www.energystorageexchange.org/projects/136. December 23, 2015.

8.0 Discussion

As the U.S. policy and industrial communities grapple with movement both domestically and abroad toward energy portfolios that include larger proportions of renewables and other low-carbon power generation technologies, there is a growing need to address the intermittency of some of these technologies. Wind and solar power, in particular, have seen expanded deployment in many parts of the country. However, the uncertainty inherent in both production technologies require supporting technologies to ensure grid stability. Highly flexible, rapidly dispatchable generating units are currently used to fill this gap, but in some areas, the cushion of increasing and decreasing reserves available to balancing authorities may be increasingly inadequate as additional wind and solar deploy to the grid. Also, balancing needs are typically served by peaking natural gas plants, which carry a high CO_2 emissions burden, relative to baseload gas plants. As the U.S. and global economies move toward policies that incentivize decreased CO_2 emissions, via the use of cost-based mechanisms such as carbon markets or emissions taxes, the price of power will rise, in part, as a function of the carbon price associated with each individual generation technology. Rising CO_2 prices and/or subsidies associated with low-emissions or renewable electric generation will help to shift the generation mix toward lower-emitting technologies. However, as this happens, the intermittency issue will become increasingly important. Indeed, the Federal Energy Regulatory Commission (FERC) has worked to address regulatory barriers to implementation and provision of energy storage and other ancillary services (FERC 2011; 2013).

Of the many technologies available for energy storage, only a few are available to address grid-scale storage needs. Of these, CAES and pumped hydroelectric storage are among the most oft-discussed. While CAES offers significant potential, its deployment has been limited by the need for a salt cavern to hold compressed air. In previous work to address energy storage needs in the Pacific Northwest (McGrail et al., 2013) and in Texas (McGrail et al., 2015), the authors have examined the potential for porous geologic media – basalts and sandstones, respectively – to serve as storage reservoirs for compressed air, obviating the need for a salt cavern and potentially making CAES accessible in a wider geographic area. In both studies, CAES has been evaluated using a geothermal energy component to provide cooling, air preheating prior to turboexpansion, or both. While the geothermal aspect of the concept appeared technically and economically feasible in both studies, the difficulty associated with finding a location that possessed both high quality geothermal resources and suitable reservoir geology for the air storage portion of the project posed significant challenges to the broad applicability of the concept. In this study, the authors have attempted to address this challenge by evaluating the use of existing wellfield infrastructure—wells and existing casing strings—to serve as storage containers for compressed air, in lieu of a geologic reservoir. This is appealing for a number of reasons, but particularly for the potential it holds to leverage existing capital and field data for energy storage while also limiting the pressure effects associated with injection of compressed air into geologic reservoirs. In conjunction with an existing or new geothermal generation project, this technological approach could offer a zero-emissions, grid-scale energy storage capability which would leverage one form of renewable energy to facilitate the integration of others. Aside from the "green" appeal of such an approach, it would also assume less overall project risk associated with carbon price volatility, and could qualify for credits or subsidies. Also, as noted earlier, FERC and many states, including California, are recognizing the importance of balancing and ancillary services, and are working to make these projects easier to implement. With capital costs well below those for pumped hydro, and without the financial liabilities associated with future carbon emissions that would be borne by conventional CAES plants (i.e., coupled with gas-fired generation), the well-based, geothermally-coupled CAES concept evaluated here appears to be competitive, particularly in a carbon-constrained future where a higher premium is placed on availability of resources to balance intermittent renewables.

Analysis of the arbitrage economics under both a simplified, fixed-period dispatch scheme and a more realistic market-driven case suggest that, under current market conditions in CAISO, the project as evaluated here is unlikely to be economically attractive. Still, even under the relatively narrow $20/MWh price spread (averaged for the simplified dispatch case), a 15.4 MW facility could break even on arbitrage at a utilization rate not far from the 17% assumed in the initial analysis. While that accounts only for power trading revenues and costs, it does suggest that arbitrage may play a significant role in project economics, in addition to value streams derived from ancillary services. Once in generation mode, the CAES project could be dispatched as either balancing or voltage regulation, allowing a project such as this to leverage multiple value streams, as well as qualifying for potential renewable, low-carbon and energy storage development and production incentives.

Also, while the configurations examined here assumed optimized use of each geothermal extraction well—where one geothermal well was estimated to support as many as 35 compressed air storage wells—it is also possible to employ a slipstream approach, taking a small fraction of the geothermal steam from a standard production well to provide heat needs during CAES cycles, and using it for standard production during all other periods. This would allow for the implementation of smaller, scalable systems. Alternately, a similar scaled approach could be implemented to get additional utility from marginal geothermal production wells, should the CAES option provide a higher value-added than continued production or abandonment of the well.

While the economics and market conditions suggest that this hybrid, zero-emissions approach to energy storage is both technically feasible and may become increasingly attractive as society moves toward a lower-carbon future, a number of uncertainties currently pose barriers to adoption of well-based CAES, including the practicality and costs of reusing existing infrastructure and the degree to which well materials can withstand pressure cycling under conditions beyond those considered during original completion. Addressing these technical considerations will help validate the economic feasibility of this hybrid geothermal implementation, which in turn will help industrial developers to consider this alongside other capital investment projects, including those focused on energy storage.

Should well-based CAES prove economically feasible, its implementation under this hybrid geothermal approach could offer an opportunity to increase the deployment of geothermal technologies while also bolstering grid stability and facilitating additional wind and solar development. By leveraging the enormous capital and data assets present in existing oil, gas and geothermal fields, GT-CAES could offer cost competitive, zero emissions, grid scale energy storage at capital costs that are well below those associated with conventional baseload geothermal development. Resolving the remaining technical challenges via field testing will help to determine the degree to which this approach could deploy, and could offer the U.S. and the global energy community another technology to help in the move to a lower-carbon energy future.

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