Transforming our energy systems by securing U.S. leadership in clean energy technology…

Baseline System Costs for 50.0 MW Enhanced Geothermal System
-- A Function of: Working Fluid, Technology, and Location, Location, Location --

DE-EE0002742
Final Report
30 April 2012

Team Members:

Gas Equipment Engineering Corporation
Paul Dunn, Chief Technology Officer, PI
Nancy Selman, VP Business Development
Anthony Della Volpe, CEO
Deborah Moss, Owner

GeothermEx Inc.
Dr. Sabir Sanyal, President
Steven Butler, Senior Reservoir Engineer
Robert Stacey, Reservoir Engineer
Ann Robertson-Tait, Geologist
Dr. Karsten Pruess, Scientist, LBNL (Consultant)

Plasma Energy Services, LLC
Rick Mobley, President

Turbine Air Systems
Halley Dickey, Director Geothermal Business Development

Fairbanks Morse Engines (FME)
Greg Gutoski, Technical Director

Fugro NV / Wm. Lettis & Associates
Dr. Jeffery Unruh, Vice President
Chris Hitchcock

Fort Point Associates
Jamie M. Fay, President, AICP
John T. Stitzer, PE, Project Manager

Conservation Law Foundation / CLF Ventures
Jasmine Tanguay, Project Manager
Walker Larsen, Project Specialist

Impact Technologies LLC
Ken Oglesby, PE, President

Acknowledgement

This material is based upon work supported by the US Department of Energy Award Number DE-EE0002742.

Gas Equipment Engineering Corporation (GEECO) and the authors would like to thank all who contributed to this report, including everyone listed on the front cover, and DOE participants in our workshops, in particular Ms. Arlene Anderson. The level of expertise and effort present throughout this study was unusually good.

Disclaimers

US Department of Energy: This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

GEECO and co-authors: This report is provided “as-is” and with no warranties, express or implied, whatsoever for the use or the accuracy of the information contained herein. Use of the report and the information found herein is at the sole risk of the recipient.

Executive Summary:

Substantial unexploited opportunity exists for the US, and the world, in Enhanced Geothermal Systems (EGS). As a result of US DOE investment, new drilling technology, new power generation equipment and cycles enable meaningful power production, in a compact and modular fashion; at lower and lower top side EGS working fluid temperatures and in a broader range of geologies and geographies. This cost analysis effort supports the expansion of Enhanced Geothermal Systems (EGS), furthering DOE strategic themes of energy security and sub goal of energy diversity; reducing the Nation's dependence on foreign oil while improving the environment.

This cost analysis provided a baseline cost for a 50 MW Geothermal Power Plant in a difficult environment (Massachusetts), and then assessed how that cost would change as a function of:

- Geothermal Working Fluid (carbon dioxide (CO_2) vs. Water)
- Drilling Technology
- CO_2 Generation Technology
- Other Locations

Key take away points are as follows:

1. A 50 MW EGS power plant is probably not economically viable in Western MA. This would be a $1.1B dollar project, and the single case that did make money in Massachusetts was: alternate working fluids (CO_2), available (TRL6) technology in well casing and CO_2 generation, with power sold at retail rates. All the other cases lost massive amounts of money.
2. Water can be technically used as a geothermal working fluid in essentially any location.
3. CO_2 cannot be technically used as a geothermal working fluid in essentially any location. Certain sites are better suited for sequestration, and if CO_2 EGS power systems are employed at those sites the costs associated with filling and top off of CO_2 will significantly and negatively impact the results.
4. In sites where CO_2 use is technically viable, i.e. where the reservoir can be filled and pressurized, a CO_2 EGS will in general out perform a water EGS, both technically (efficiency) and economically (LCOE).
5. For deep EGS wells, especially with CO_2, in the more challenging areas, the dominant cost was well casing (50-70% of cost). Drilling technology (faster drilling) is good and will lower cost, and DOE investment in that area must continue. However, DOE investment in well casing technology could have great impact / enable the use of CO_2 EGS.
6. Unless natural CO_2 or pipeline CO_2 at low cost exists, CO_2 EGS is essentially unaffordable unless the CO_2 is generated / captured in some type of hybrid system. If DOE is interested in CO_2 EGS, it should invest in / leverage oxy fuel or other CO_2 capture technology and consider CO_2 EGS a hybrid fossil / geothermal system.
7. Reservoir modeling / analysis, in particular for CO_2, requires further investment. Significant questions exist on the filling dynamics / leakage rate / sequestration rate. We simply do not

know that a CO_2 EGS can actually be engineered. This needs to be better modeled, and demonstrated, at least at the huff and puff level.

8. The availability of data east of the Mississippi, especially in the Northeast, is sparse and volatile. During the conduct of this report, significant update to geothermal heat maps was published impacting New England, and there are no test bores or actual data to validate those estimates.
9. In the Water EGS locations studied, both Texas and MA, the diesel driven water pump versions were significantly more cost effective than electric driven pumps (with electric power from the geothermal plant). This is likely to remain true as long as natural gas prices stay low ($4/MMBTU used herein).
10. Of the four locations chosen, Western MA, El Paso TX, Mountain Home, ID, and China Lake, the differences between the first three were significant in total cost, but not profitability. Only China Lake was exceedingly profitable. We do not believe this is a general result, but reflects limited time available to select more optimal alternative locations.

Table of Contents

List of Tables

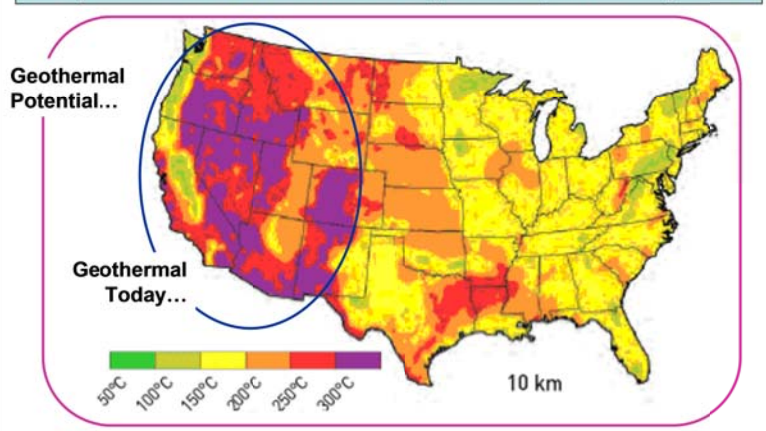
Introduction

Gas Equipment Engineering Corporation (GEECO) is pleased to have teamed with Fugro NV / Wm. Lettis & Associates, GeothermEx Inc., Impact Technologies LLC, Turbine Air Systems (TAS), Fairbanks Morse Engines (FME), Plasma Energy Services LLC, Fort Point Associates, and the Conservation Law Foundation / CLF Ventures for this effort.

Overview of US Geothermal Resource and Production Potential and Vision

Substantial unexploited opportunity exists for the US, and the world, in Enhanced Geothermal Systems (EGS). As a result of US DOE investment, new drilling technology, new power generation equipment and cycles enable meaningful power production, in a compact and modular fashion; at lower and lower top side EGS working fluid temperatures and in a broader range of geologies and geographies. This cost analysis effort supports the expansion of Enhanced Geothermal Systems (EGS), furthering DOE strategic themes of energy security and sub goal of energy diversity; reducing the Nation's dependence on foreign oil while improving the environment.

Figure 1. Exploitation of Geothermal Today is sporadic, and clustered. The potential of EGS is to exceed our requirements, and be everywhere.



As can be seen from the Geothermal Technology Program (GTP) Multiple Year Research, Development, and Demonstration (MYRDD) plan, existing geothermal power plants in the continental US are all west of the Mississippi. Nearly all of the existing projects are near the red / purple zones of Figure 1, i.e., inside the oval nominally marked as "geothermal today". Moreover, none are at the depths approaching 10 km (30,000 ft). The new technologies that potentially enable deeper and cheaper wells and the potential use of higher efficiency, integrated, direct and binary generation equipment to produce orders of magnitude more electricity open up the aperture for the exploitation of geothermal resources to include nearly all the lower 48 states up to a 10 km depth.

When looking at Figure 1 with the aforementioned in mind, America's geothermal potential in the lower 48 states includes every geology and geography in yellow, orange, red and purple with and without outward manifestations of geothermal activity. That area of opportunity includes geography which is home to a majority of America's cities, towns, industries, institutions, infrastructure and population which are all locations with ready access to North America's existing electric grid.

The only geographies in the lower 48 states without geothermal potential at up to a 10km depth with the technologies discussed above are in the green shaded areas. "Since subsurface heat with the potential to produce electrical energy exists underneath a vast majority of the United States, geothermal energy has the potential to provide clean, affordable energy which will diversify our national energy portfolio and increase energy security" (MYRDD, Section 1.2, Page 8).

However, development of EGS cannot and will not occur unless:

- Technical risk is reduced to acceptable levels – i.e. viable working fluid flow rates (heat transport) are proved to be achievable, and once achieved, sustained, and
- Accurate understanding of the cost of construction, development, and operation exist – i.e., financial risk is lowered to an acceptable level.

This project has been focused on the latter point.

Project Location

The desire to study a Project location east of the Mississippi led the group to start looking in western Massachusetts, which is close to major load centers of the Boston to New York corridor, but is also relatively rural with appropriate land use characteristics for a large geothermal project. The proposal to DOE named Hadley, MA area as the site, which is home to five college campuses with significant power requirements. It was believed that at least one of the colleges had not only an interest in hosting a sizable renewable energy project, but also the ability to use its endowment to help finance such a project.

Upon the commencement of the Project, the Team set criteria for the site. It was acknowledged early on that a 50 MW geothermal project in the northeastern US would require about two square miles of contiguous area, and pose some very complex land use and permitting risks. Therefore, a simplifying assumption was made: that each of the Project sites would be at a "single cooperative" landowner. In the vicinity of Hadley, MA, this pointed to Westover Air Force Base (AFB), located in Chicopee, MA. Westover AFB has the dual benefits of being in the same geothermal basin as the original site in Hadley, and having one governmental landowner.

At the level of detail studied herein, the results at Westover AFB would apply equally well in the towns of Amherst, South Hadley, Hadley, Northampton, which are the homes of many of the area colleges.

Technical Design Methodology

The current state of the art for Enhanced Geothermal Systems (EGS) involves the pumping of high pressure water down one or more "injection wells" where at depth it encounters the fractured hot rock of the geothermal reservoir. The fractures, produced artificially in the development phase or naturally occurring, are such that the EGS working fluid (water) can migrate through the cracks, picking up the heat from the surrounding reservoir, and find its way to one or more "production" wells. The reservoir must also be developed or naturally occurring in a way such that the losses of working fluid are minimal; since pumping water consumes power, and any fluid lost is wasted energy. The pumping power, defined by the flow and the pressure drop of the water as it flows through the reservoir, must be sufficient to support return flow from the production wells at meaningful rates. The production well casing or pipe must also be designed in a way such that heat loss of the working fluid as it flows back to the surface is as low as possible.

Theoretical analyses and computer modeling have suggested favorable properties for CO_2 as a heat transmission fluid for EGS (Pruess, 2006). Specific advantages (and one penalty) predicted for CO_2 as compared to water in EGS include the following:

- For a given down well pressure difference between injection and production sides of an EGS, CO_2 flows at much higher mass rates than water and achieves approximately 50% larger heat extraction rates for reservoir temperatures near 200 deg C.

- There exists a relative advantage of CO_2 over water as heat transmission of the fluid becomes greater at lower reservoir temperatures.

- CO_2 has large thermal expansivity, and thermal buoyancy effects between cold fluid in the injection well and hot fluid in the production well are much stronger than for water. This is expected to generate large overpressures at the production wellhead, obviating the need for pumping to keep fluid circulating.

- The same thermal buoyancy effects that would generate large overpressures in the production well also provide an engineering tool for avoiding premature breakthrough of cold injected CO_2 at the production well(s), by means of an “inject deep, produce shallow” design (Pruess, 2008).

- CO_2 is not an ionic solvent, so that its chemical interactions with rock minerals would be much weaker than for water. Dry (anhydrous) CO_2 would not produce strong dissolution, precipitation, and scaling effects, as occur in water-based systems.

- CO_2 EGS can provide a higher net “earth cycle efficiency” than a water EGS; enabling a smaller reservoir

    - Slightly less than a 3x improvement in cycle efficiency in a 400 deg F, 15,000 ft geothermal system (Dunn, Mobley, Gutkowski, SMU 2009)

- A notional 50 MW CO_2 EGS was estimated to require \$210M of CO_2 at purchased delivered price, creating a significant barrier to implementation (Dunn, Mobley, Gutkowski, SMU 2009)

    - Though generation of CO_2 (and power) on site from a hybrid system could potentially remove that barrier

The proposed use of CO_2 as heat transmission fluid in EGS raises new issues, directly relating to cost. For water-based systems, fluid circulation and heat extraction can commence immediately following reservoir stimulation. In contrast, for CO_2, reservoir stimulation would be followed by an intermediate step of reservoir development, in which CO_2 would be continuously injected to remove the water. Removal of water would occur through (1) immiscible displacement of aqueous phase by the supercritical CO_2-rich phase, and (2) dissolution of water into the flowing CO_2 stream. The initial phase of EGS-CO_2 reservoir development would likely lead to enhanced chemical reactivity, due to the presence of water-CO_2 mixtures. CO_2 injection and associated reservoir pressurization would generate a production fluid stream that initially would be single-phase aqueous, then would transition to two-phase water-CO_2 mixtures, and eventually would dry out to produce a single supercritical CO_2 phase.

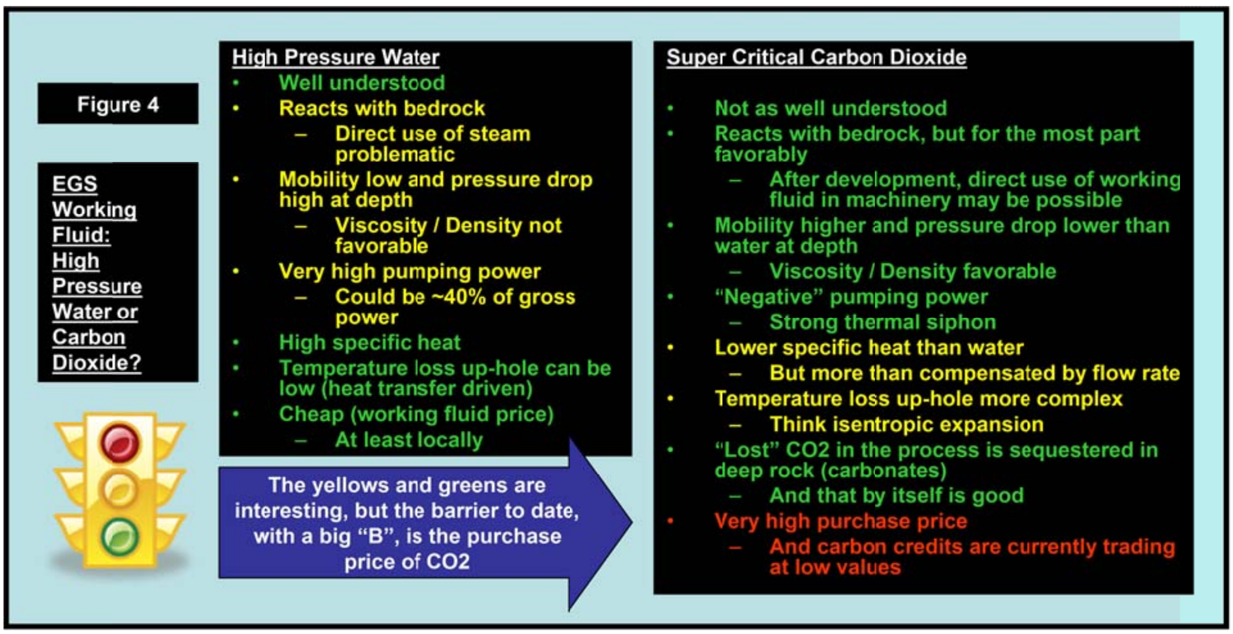


Figure 2: Comparison of Water and CO_2 EGS

A summary chart comparing the CO_2 and Water EGS is provided above. The cost barrier, and questions in general about the cost of EGS in areas far from currently developed systems, led to the effort herein.

Scope of Effort

Statement of Objectives: SOPOs 1-4

Consistent with the vision for the project, and DOE's goals, the team had the following four objectives, which were translated into SOPOs 1-4 for the Project:

1. Develop a baseline cost model of a 50 MW Enhanced Geothermal System, including all aspects of the project, from finding the resource through to operation, for a particularly challenging scenario: the deep granitic rock of the pioneer valley in western Massachusetts.
2. Develop an understanding of how that cost model changes (and hopefully improves) with the change from H_2O -EGS to CO_2-EGS.
3. Develop an understanding of how that cost model changes / improves with respect to key technologies, specifically:
   a. Conventional vs. Advanced Drilling Technology, and
   b. CO_2-EGS hybrid power system gas generation and processing approaches.
4. Develop an understanding of how that cost model changes / improves with respect to "location, location, location", specifically:
   a. Temperature profile vs. depth
   b. Geology, geo chemistry (rock type, porosity, etc)
   c. Local electric rate (as it applies to the effective cost of CO_2, and EGS ROI overall).

A 50 MW project has been chosen as a design point, to provide the ability to assess how different machinery approaches will change the costing. That is, 50 MW is a mid-point in geothermal project size where multiple solutions exist. Choosing 50 MW as the project size allows the analysis team to effectively explore the options in the design space and understand the cost.

This model and the variation in the aforementioned conditions will help answer key questions regarding the economic viability of EGS, and to what extent can the vision of EGS be achieved anywhere.

Definition of Terms

Throughout this document, the terms Water EGS, Hybrid Diesel Water EGS, and CO_2 EGS, and Hybrid CO_2 EGS are used.

Water EGS and Hybrid Water (Diesel Pump) EGS:

A simplified view of an Enhanced or Engineered Geothermal System (EGS) is provided below.

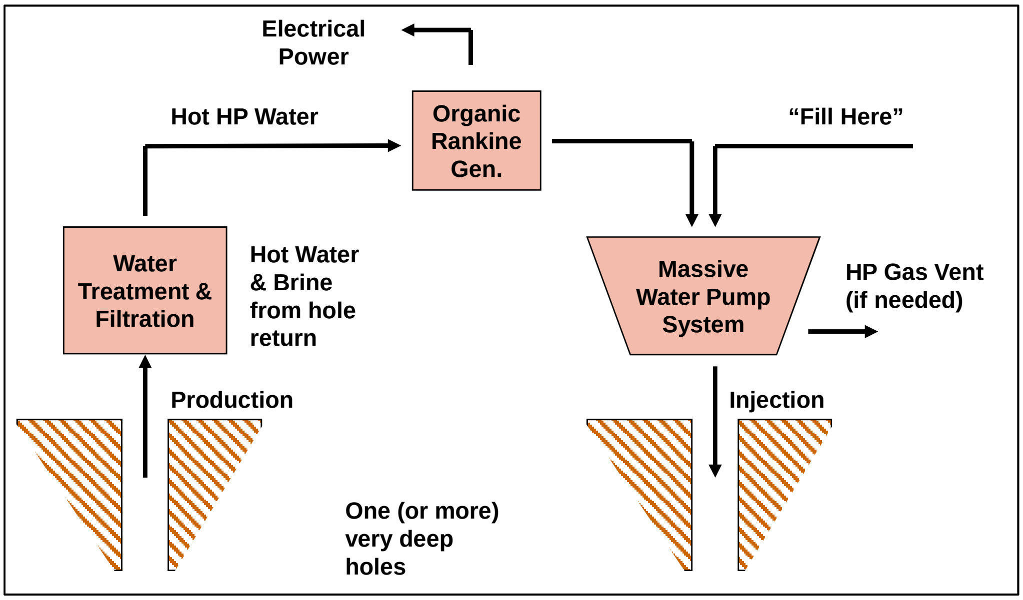


Figure 3: Organic Rankine Cycle for Water EGS System

In a water EGS system, the fluid or brine is circulated to extract heat from the earth, and that heat is converted to electrical power via an Organic Rankine Cycle (ORC) heat recovery generator. As will be discussed in more detail in later parts of this report, the water pump power can be a large fraction of generated power, at relatively low temperature systems (~300 F), and with tight formations, 30-50% of gross power for the water pump can be expected. Often, since geothermal power (or any renewable power) is of greater value (sales price or tax credit) than grid or mechanically generated power, a hybrid system is considered where the water pump power is provided from another source. The most sensible source at today's natural gas price ($4/MM BTU or less) is engine driven. In this report, hybrid water EGS is defined as water EGS with the water pump power provided from a gas fueled or dual fueled (natural gas / diesel) diesel engine. Note: It is understood that most water EGS would not have one "massive water pump", and would instead use a combination of production well pumps (in each production well), and one or more injection well pumps.

CO_2 EGS and Hybrid CO_2 EGS:

The CO_2 EGS is schematically similar to the water EGS. The CO_2 could be used as the water is to carry the heat from the earth up to ORC equipment, but generally greater efficiency is obtained if the gas (super critical fluid) is expanded directly in power generation machinery. The chart below shows the basic pieces of the CO_2 EGS and indicates that the ORC is optional. In most cases, the ORC is not preferred, and for an extremely hot EGS, or in the case of very high pressure (strong siphon) the ORC could actually be placed after the expander. This would generally not be an advantage in terms of cycle efficiency, but would reduce the expense associated with the ORC evaporator heat exchanger (for example designed for 1,000 psig vs. ~5,000 psig).

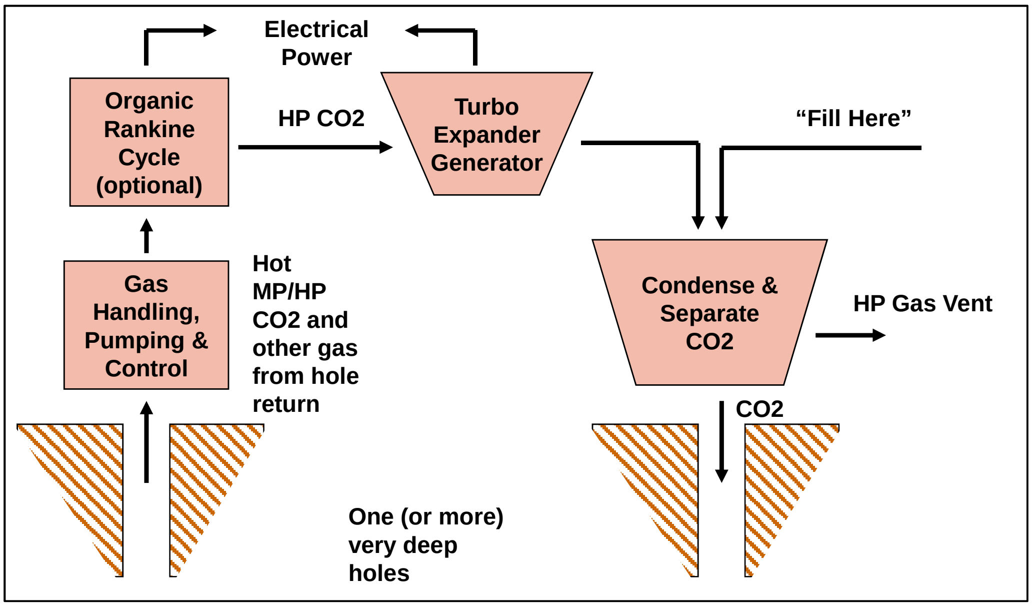


Figure 4: Organic Rankine Cycle for CO_2 EGS System

The aforementioned schematic is representative of the purchased CO_2 case. Some other system, for example a large number of liquid CO_2 trucks and pumps are providing the CO_2 at pressure as noted: "fill here". In the case of the Hybrid CO_2 EGS, the CO_2 is generated on site at pressure from a power system. Candidate systems with inherent CO_2 capture would include oxy-fueled power systems (e.g. Rankine, diesel), or certain fuel cells (molten carbonate) which produce the CO_2 as a separated stream as part of the process. In theory, the value of the power generated from these systems offsets the price of the fuel / maintenance, effectively reducing the price of the CO_2 to an acceptable level. A schematic for a hybrid CO_2 EGS using a semi-closed cycle (oxy fired) diesel / natural gas engine is provided below.

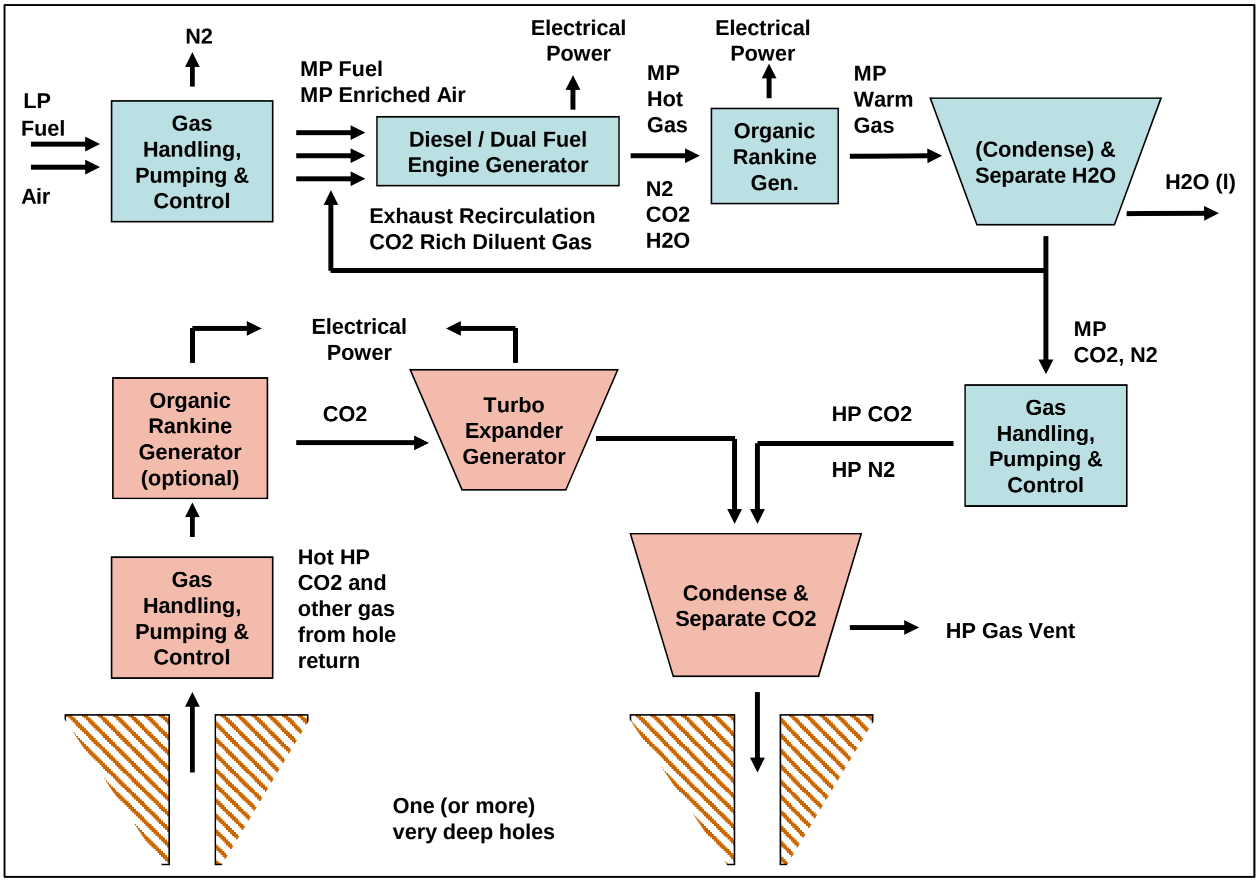


Figure 5: Hybrid CO_2 EGS System

Discussion of Work Breakdown Structure (WBS) Areas

Development of the baseline cost of an Enhanced Geothermal System, whether conventional pumped water or a novel hybrid CO_2 system, and regardless of power level, requires a understanding of the "sequence of events" and the cost drivers associated with the sequence of events that must occur through the process of initial site identification, assessing, selecting, designing, constructing, developing / starting, and operating an EGS. Baseline cost must consider, but is not limited to, the designs, work plans, and systems costs associated with the following 10 Work Breakdown Structure (WBS) areas:

1. Exploration: Geothermal resource identification, qualification, analysis and quantification;
2. Reservoir Development (below ground level): Engineered CO_2 EGS and H_2O EGS geothermal reservoir planning, development (drilling, fracturing, casing), management and ongoing monitoring;
3. Reservoir Development (top side equipment): CO_2 gas management (generation, purification, dehydration, compression) systems and equipment and H_2O EGS fluid management (pumping, replenishment, treatment) systems and equipment;

4. Power Generation Equipment: CO_2 EGS direct high pressure CO_2 expander / generator or H_2O EGS Organic Rankine Cycle heat recovery generator and associated auxiliary systems, including cooling and all controls;
5. Onsite Integration: CO_2 EGS and / or H_2O EGS integration and interconnection to local heat and power generation and distribution infrastructure;
6. Grid Interconnection: CO_2 EGS and / or H_2O EGS integration and interconnection to the commercial power grid;
7. Civil Works: Top of well sites and facilities to house surface elements of 50 MW CO_2 EGS and 50 MW H_2O EGS applications;
8. Site Control: Land acquisition and / or land use w/ royalty agreements;
9. Permitting and Regulatory: Federal, State local and private (stakeholders) permits, approvals incentives leading to and enabling construction and operation of CO_2 EGS and H_2O EGS applications at 50 MW;
10. Project Management: Project management requirements and costs associated with a 50.0MW CO_2 EGS and 50 MW H_2O EGS applications of this scale and magnitude.

Overview of Existing Cost Models

Currently, the GETEM geothermal cost model that was developed for the Department of Energy's Geothermal Technologies Program is *not* configured to analyze CO_2 EGS. The GETEM model does provide a method for quantifying the power generation cost from conventional geothermal energy, and a means of assessing how technology advances might impact those generation costs. It is anticipated that the results of this Project might be used to update the GETEM model to provide a way to analyze EGS power generation costs in the future. Drilling cost estimates in GETEM use Well Cost Lite. Estimates herein are consistent with GETEM.

Cost Model Methodology

A team with broad experience in geothermal technology and supporting system components was established to develop a baseline cost model (SOPO 1) consisting of 10 excel worksheets covering the 10 WBS areas (see above), plus a summary worksheet rolling up the 10 WBS cost areas into a final system cost. The baseline cost model was then exercised to assess variations in working fluid, top side equipment, construction / drilling technology, and location characteristics (SOPOs 2,3, and 4).

The team members and their assigned cost areas are as follows:

Table 1: WBS Cost Areas

WBS Cost Area		***Team Member***
1	Exploration	Fugro NV / Wm. Lettis & Associates
2	Reservoir Development (subsurface)	GeothermEx; Impact Technologies
3	Pumping and Backup Power Generation	Fairbanks Morse Engines (FME); Plasma Energy Services; GEECO
4	Power Generation Equipment	Turbine Air Systems
5	Onsite Integration	GEECO
6	Grid Interconnection	GEECO
7 8 9 10	Civil Works Site Control Permitting and Regulatory Project Management	Fort Point Associates; CLF Ventures

GEECO managed the Project and led the Team, assigning responsibility for the investigation of specific cost areas to each team member chosen for its expertise in the relevant WBS area. Numerous team and meetings were held in person and by teleconference throughout the study period to discuss the results of each team's WBS cost research and development. GEECO then integrated the WBS cost information into one excel spreadsheet based cost model for each of the SOPOs 1-4, and produced this final report, with substantial input from the team.

SOPO 1 - Cost Baseline Result for H_2O EGS at Westover AFB, South Hadley, MA

Overall Methodology

The overall methodology for the costing effort was design based, and as previously discussed, assessed in parts via a Work Breakdown Structure (WBS) methodology. The first effort was to design the water based EGS, for the most stressing environment, Western MA, with relatively cool temperatures. This would produce a field design of injectors and producers, and associated costs. As the technology or environment changed, either enabling deeper and hotter wells or higher cycle efficiency systems, the number of producers and injectors would be reduced from the original design and associated cost savings calculated.

WBS 1 - Exploration

WBS 1 - Geothermal resource identification, qualification, analysis, and quantification - evaluates the cost of site selection and detailed survey of the EGS site. Fugro was selected for this task. The table below is a breakdown of these costs, which total $3.71 million.

Table 2: Cost Summary for WBS 1 - Geothermal Resource Identification, SOPO 1

1.0	**$3,710,000**	**Geothermal resource identification, qualification, analysis and quantification**
1.1	**$25,000**	Literature Review, Data Compilation, and Preliminary Interpretation: Includes development of comprehensive workplan.
1.2	**$45,000**	Regional Reconnaissance: Satellite-based geologic mapping, with limited field reconnaissance, to evaluate potential geothermal resources.
1.3	**$185,000**	Detailed Area of Interest Reconnaissance: Satellite and airborne geophysical surveys of area of interest. Includes high-resolution aeromagnetic survey will be used for the detection and detailed mapping of faults and fractures throughout the sedimentary
1.4	**$25,000**	Detailed Field Reconnaissance: Includes field mapping of site vicinity, sampling of rock outcrops and existing water wells, limited laboratory testing including geochemical testing of groundwater samples.
1.5	**$375,000**	Seismic Data Acquisition (2D Reflection): Includes three lines (13 miles total), including 2 – 30,000 ft and 1- 10,000 ft 2D reflection and refraction profiles (10 ft station interval), along with velocity tomogram and depth migration.
1.6	**$1,435,000**	Exploratory Drilling: Includes three (3) shallow exploratory wells to 300 ft depth, eight (8) Geothermal Gradient Wells to 1,600 ft depth, and three (3) wells to 6,000 ft depth.
1.7	**$175,000**	Downhole Geophysics/Packer Tests/Laboratory Testing: Includes downhole optical televiewer, caliper, and relevant geophysics tests along with one packer test per boring and laboratory testing of selected samples.
1.8	**$1,280,000**	Seismic Monitoring Array Installation*: Installation of a downhole twelve-station digital seismographic network using three-component borehole seismometers.
1.9	**$40,000**	Induced Seismicity Hazard Evaluation: Includes Probablistic Seismic Hazard Evaluation of Baseline Seismic Hazard and additional hazard from hydroshearing to create EGS reservoir.
1.10	**$50,000**	Data Analysis/Reservoir Quantification: Includes documentation of all data collection procedures, data reports, interpretation, and three-dimensional modeling of EGS reservoir.
1.11	**$75,000**	Final Report: Includes field and office meetings, interim reporting, and project management.

* Note: Yearly maintenance costs are estimated at $166,000 to maintain the downhole seismic monitoring array, collect and process the seismic data, and provide ongoing interpretation of the seismic results as part of a comprehensive seismic monitoring pro

WBS 1 quantifies the cost of integrated geologic, geophysical, and subsurface investigation of potential geothermal resources in the vicinity of South Hadley, Massachusetts. The following describes a scope of work, general assumptions, and associated cost estimate for WBS 1.

The purpose of the WBS 1 study is to provide baseline system costs associated with a comprehensive investigation required to provide geologic, geophysical, and engineering geology data for development of a 50 MW enhanced geothermal energy-to-electricity facility. The proposed EGS site is within an area of potentially elevated crustal heat flow identified in MIT's recent report on 'The Future of Geothermal Energy' (Tester et al., 2006) based in part on the regional heat flow data set used to produce the Geothermal Map of North America, published by the American Association of Petroleum Geologists (AAPG) (Blackwell and Richards, 2004; Figures 1 and 2).

Below is described Fugro's understanding of the geologic setting, how the geology of the area may be conducive to geothermal development, and the proposed scope of work to evaluate the presence of economically viable geothermal resources at target depths. Fugro also presents their understanding of potential subterranean heat source targets that may be accessible with modern drilling technology based on our review of regional and local geology. Fugro's project work plan includes application of established, state-of-the-practice satellite, airborne, and field based mineral and geologic exploration techniques to characterize the geothermal resource and area of interest. It includes estimated costs for installation of a seismic monitoring network and development of a defensible assessment of the seismic hazard and risk associated with the hydroshearing operation required to develop an EGS reservoir.

Background

Geothermal resources in the eastern United States generally are associated with lower heat flow and are isolated and less well characterized than those under development in the western United States. The "average" heat flow for the eastern United States is 55 to 60 milliwatts per square meter (mW/m2). The most prospective crustal heat sources in the eastern U.S. are granitic intrusive rocks (particularly those that are rich in uranium, thorium and potassium), which generate heat by radioactive decay (Tester et al., 2006). Maps produced by the Southern Methodist University Geothermal Laboratory (Blackwell and Richards, 2004), delineate an area of elevated heat flow in New England that extends from New Hampshire south into Massachusetts (Figures 1 and 2). Based on several isolated heat flow measurements in deep boreholes, elevated values of 68 to 69 mW/m2 are present, at least locally. These limited observations coincide with known high heat flow areas in the eastern United States where crustal radioactivity is high (Birch et al., 1968). As noted by MIT, detailed exploration studies are necessary to identify the highest temperature locations, because the density of heat flow data in the eastern United States is low and delineation of smaller targets requires a higher density of data points. The ideal situation for a thermal anomaly in these older rocks is a thick granitic pluton overlain by thermally insulating sedimentary rocks one or more kilometers in thickness (Birch et al., 1968; Tester et al., 2006). These conditions may be present in the proposed study area.

Geologic Setting

South Hadley is located in the north-central part of a broad structural lowland in central Connecticut and Massachusetts known as the Hartford Rift Basin. The basin is a halfgraben bounded by the west-dipping, listric Eastern Border Fault (EBF). The Hartford basin is separated from the Deerfield basin to the north by the Amherst block, an inlier of Paleozoic basement of the Bronson Hill anticlinorium down-faulted by the EBF (Figures 4 and 5). The Deerfield and Hartford basins together comprise the Connecticut Valley basin. Paleozoic basement rock present at depth (1 to 3 km) beneath the Connecticut Valley basin consists of faulted margins of the Bronson Hill anticlinorium and Connecticut Valley synclinorium, major structural features of the Appalachian system that extend from New Hampshire to Massachusetts. Borehole-based thermal gradient measurements obtained from granitic rocks in the core of the Bronson Hill anticlinorium north of the area of interest have documented relatively elevated crustal heat flow (Figures 1 and 2). Portions of the Belchertown intrusive complex exposed northeast of Mt. Holyoke College, and believed to extend beneath the Hartford basin, contain an unusual amount of allanite, a member of the epidote mineral group with up to 3% thorium and rare earth elements (Brophy, 2007). Heat provided by radioactive decay in these elements might be trapped by the overlying Triassic – Jurassic sedimentary basin fill rocks and exposed deep circulating waters to elevated temperatures, although no thermal springs have been identified. The principal concentration of allanite is found in the western portion of the complex downdropped by the EBF and now buried beneath sedimentary basin rocks. However, the absence of thermal springs has precluded any additional investigation of possible deeper heat sources. Much of the groundwater in the area is from shallow aquifers. The Belchertown intrusive complex and associated crystalline rocks, are overlain by the Mesozoic Holyoke Basalt, a columnar flood basalt that forms a thick, laterally extensive (125 km north–south, and 50 km east–west), subhorizontal sheet beneath the Connecticut Valley Basin. The Holyoke Basalt is 300 to 400 ft thick in the Mount Holyoke quadrangle. Flood basalts, and the Holyoke Basalt in particular, have been identified as a potentially important host or reservoir for geologic sequestration of anthropogenic CO_2 (McGrail et al., 2006). Most lava flows have flow tops that are porous and permeable and have enormous capacity for storage of CO_2. Interbedded sediment layers and dense low permeability basalt rock overlying sequential flows may act as effective seals allowing time for mineralization reactions to occur. Also, the thick homogeneous basalt flows may serve as a thermal 'blanket' trapping underlying heat generated by radioactive element decay. Relatively thin (100 to 200 feet thick) deposits of glacial till laid down beneath the last (late Wisconinan; about 10,000 to 20,000 years ago) ice sheet blanket the bedrock. Lower-lying areas are underlain by softer sedimentary bedrock (sandstone, siltstone, and shale) and glacial meltwater deposits (gravel, sand, silt, and clay) laid down in glacial Lake Hitchcock during the retreat of the last ice sheet. A literature search and field observations by Brophy (2007) provided no evidence of springs or groundwater of elevated temperatures in the vicinity of our proposed detailed area of geothermal interest in the vicinity of South Hadley, Massachusetts (Figure 3). A 25-foot deep water well in Hadley was reported to yield water at 15.6° C (60°F), but attempts to locate the well failed (Gruy Federal, personal communication cited in Brophy, 2007). Completed in glacial sediment, this well may overly the buried Belchertown bedrock complex, containing rock with possible elevated crustal radioactivity as described in detail below.

Occurrence Model for Geothermal Resource

The New England study region is located within a stable continental setting far from any active plate boundaries. High-temperature geothermal resources are typically found where large-scale plate boundary and volcanic processes advect heat from deep within the Earth's mantle to upper crustal levels (Walker et al., 2005). It is very unlikely such processes are occurring at depth in the study region. A working hypothesis or "occurrence model" (Walker et al., 2005) for a potential low-temperature geothermal resource in the vicinity of South Hadley assumes that the primary source of heat responsible for the elevated temperatures and heat flow measured locally is decay of radiogenic nuclides concentrated in igneous intrusive rocks, such as the granitic rocks in the core of the Bronson Hill anticlinorium. Brophy (1983) reported a few local geothermal gradient measurements of about 18.5 C/km to 23.5 C/km in a broad region encompassing the northwest corner of Maine and New Hampshire, and southwestern Vermont, and water temperatures of about 9 C to 14 C at depths of 50 m to 250 m in bedrock wells in the communities of Chicopee and Springfield. If these surface observations are simply extrapolated to depth, then temperatures in radiogenic rocks at about 2500 m may approach 55 C (131°F) to 73 C (163°F). If the radiogenic intrusive rocks are overlain by thick layers of sedimentary and volcanic strata that are less thermally conductive, then temperatures in the intrusive rocks below the "blanket" of overlying rocks may be higher than predicted by simply extrapolating the above relationships to depth. The "blanket' of sedimentary and volcanic rocks also may serve as a seal for CO_2 sequestration.

Based on these observations, a potential exploration approach for the South Hadley area would be to drill through the overlying sedimentary and volcanic cover and intersect the heat-producing radiogenic rocks in the upper 2000 m to 4000 m if possible. The drilling also could be targeted to intersect a major fault or fracture system, such as the bounding faults of the Hartford Rift Basin, which may form a naturally fractured reservoir for circulation of the working fluid. The faulted rocks also could be artificially stimulated and fractured to form an engineered reservoir. This simple model assumes that there is no regional convective flow of groundwater that may locally perturb the geothermal gradient. This "occurrence model" can be tested against data collected during compilation and interpretation phases early in the project, and further refined as needed. As the project progresses, the refined occurrence model will provide guidance for narrowing and targeting the focus of the investigations, and ultimately contribute to siting exploration and development wells.

Scope of Work and Assumptions

The project goal is to identify and characterize a source of relatively elevated heat production that is of sufficient scale and at economic depth for EGS resource development. Potential geothermal resources in the study area can be identified through analysis of heat-flow data, depth to appropriate crystalline reservoir rocks, and the physical and chemical properties of those reservoir rocks. Data sets include regional geophysical surveys to evaluate the depth, shape and extent of potential source rocks for radiogenic heat; and thermal, hydrologic and other borehole data that are crucial to understanding the heat sources.

Geological, hydrogeological, geophysical, and geochemical techniques are proposed to identify and quantify geothermal resources in the vicinity of South Hadley, Massachusetts. Geological and hydrogeological studies involve mapping any hot springs or other surface thermal features and the identification of favorable geological structures. These studies are used to recommend where production wells can be drilled with the highest probability of tapping into the geothermal resource. Geophysical surveys are implemented to evaluate the shape, size, depth and other important characteristics of the deep geological structures by using the following parameters: temperature (thermal survey), electrical conductivity (electrical and electromagnetic methods), propagation velocity of elastic waves (seismic survey), density (gravity survey), and magnetic susceptibility. Geochemical surveys (including isotope geochemistry) are an effective method for estimating the minimum temperature expected at depth. Site selection is often based on regional heat flow distribution determined from drilling relatively shallow temperature-gradient exploration wells. However, the temperature gradient measured at relatively shallow depths cannot be extrapolated downward indefinitely because of intervening geological conditions such as the thickness of sediment cover on the basement, lithology changes, and radioactive heat generation in the basement. We propose shallow (1,500 to 1,700 foot deep) exploratory borings to obtain temperature gradient information and evaluate site subsurface conditions. Because developing a reservoir for water or CO_2 injection at depth may require opening fractures at depth, the regional stress regime is an important consideration for design of final production drilling strategies (MIT). In identifying the appropriate reservoir development plan, the most favorable factures would be those created along the direction of maximum shearing stress. It is therefore important to have information on regional stress direction and magnitude in the planning of EGS geothermal development.

Workplan

According to an August 2005 report by the Geothermal Energy Association (GEA, 2005), exploration (including geological studies, drilling, and confirmation) is typically up to one third of the overall costs of a geothermal project. The greatest typical expense is drilling exploratory borings for temperature gradient measurements and evaluation of subsurface conditions. These borings are labor intensive and require expensive drilling equipment and support logistics while only providing single data points for evaluation. However, because geothermal resources are buried deep beneath the surface of the earth they cannot be verified without borehole data. Development of a three dimensional geologic model prior to drilling reduces uncertainty, allows for targeted wells, and provides a context for interpretation of the well results. Our proposed project work plan is tailored to use established, state-of-the-art satellite, airborne, and field-based mineral and geologic exploration techniques to characterize the geothermal resource and area of interest to the greatest degree possible while minimizing the number of exploratory bore holes required. In order to develop the necessary information for identifying and characterizing a potential geothermal resource in the proposed study area, we propose the following eleven (11) primary tasks:

Task 1 - Literature Review, Data Compilation, and Preliminary Interpretation

Task 2 - Regional Reconnaissance - Satellite-based Mapping (Correlation of Heat-Flow Data)

Task 3 - Detailed Area of Interest Reconnaissance – Satellite and Airborne Surveys

Task 4 - Detailed Field Reconnaissance

Task 5 - Seismic Data Acquisition (2D Reflection)

Task 6 - Exploratory Drilling

Task 7 - Downhole Geophysics/Packer Tests/Laboratory Testing

Task 8 - Seismic Monitoring Array Installation

Task 9 - Induced Seismicity Hazard Evaluation

Task 10 - Data Analysis/Reservoir Quantification

Task 11 - Reporting

Each of these tasks is described in more detail below, along with the major assumptions used in estimating costs, with estimated costs provided in the accompanying excel WBS spreadsheet.

Task 1.1: Literature Review, Data Compilation, and Preliminary Interpretation

Task 1.1 consists of a desktop study that utilizes existing information to characterize the geologic setting, regional structure, and possible sources of elevated subsurface heat flow in the region. The primary purpose of the data compilation is to provide context for interpreting data developed during subsequent tasks and identifying initial target areas for subsurface investigations to assess the presence or absence of shallow heat sources. During this task, geologists will review scientific articles, consultants' reports, regional mapping of geologic and geographic features, modern and historical aerial photography, digital elevation maps, geophysical data, and pre-construction maps, and conduct interviews with scientists having relevant geologic expertise in the region. The data compilation task includes development of a project GIS. The compiled data should be integrated into a common "platform" such that all data are properly georeferenced and may be cross-referenced in the context of bedrock geology and geologic structure. Examples of databases to be included:

- Digital terrain maps
- Heat flow databases
- Bedrock type and structure
- Quaternary geology and geomorphology
- Soils
- Groundwater wells
- Faults
- Bedrock lineaments

The products of the data compilation and initial interpretation task should include an annotated bibliography of compiled references. In addition, a project GIS will be created that incorporates readily available data layers. Total estimated cost for Task 1.1 is $25,000.

Task 1.2: Regional Reconnaissance

Regional geothermal reconnaissance screens a region of thousands of kilometers in order to identify and focus on areas of potential interest. It involves geologic studies, analysis of available geophysical data, and geochemical surveys to identify more limited areas for detailed exploration. Satellite-based mapping would include hyperspectral imaging using available satellite imagery of the region to characterize bedrock lithology. Using Landsat ETM+ data (15 m resolution, eight-band imagery) and

Digital Elevation Model (DEM) topographic data (30m SRTM DEM data or better from USGS), specialists would remap the target area (approximately 4,000 Km2) at a scale of 1:50,000 to improve delineation of geological contacts, rock types, associated mineralogy (including radioactive elements), and controlling faults. As the area is moderately to heavily covered with either vegetation or land use, mapping the distinctive spectra that different rock types re-radiate to the satellite sensor will be muted, but some detail will be reflected and imaged. Because differences in mineralogical composition between the granitic, ultramafic, and gabbroic lithologies affect the erosion/denudation rates, it should be possible to map the compositional changes using a combination of multi-spectral imagery and artificially shaded elevation data to augment differentiation of rock types from purely spectral means. Satellite-based sensors such as Advanced Spaceborne Thermal Emission and Reflectance Radiometer (ASTER) collect data that aid in the interpretation of ground conditions and site characteristics where not otherwise possible. ASTER acquires data in 14 bands ranging from VIS, NIR, and short-wavelength, long-wavelength, and thermal infrared bands. Data resolution ranges from 15 m for the VIS and NIR wavelengths to 30 m for the short-wavelength infrared and 90 m for the thermal bands. These data will be utilized in the preliminary geologic mapping phases to facilitate recognition of features that can be observed only in small-scale views. The multispectral character of this data allows discrimination of ground cover based on substrate properties and can be used to identify different rock and soil types by virtue of their chemical composition. These data should be deaggregated to remove the vegetation component, leaving a mineralogical component that can then be related to lithology, and thus mapped geologically. The following features will be extracted and interpreted from the satellite mapping and integrated into the project Geographic Information System (GIS) database:

- Faults/shear zones
- Fractures
- Folds
- Bedding/foliation dip
- Stratigraphic contacts
- Lithological units
- Outcrop
- Subcrop
- Cover/drift rocks
- Drainage

The same data will be used to develop a model of the geologic structure in the region: faults and shear zones can affect fluid flow by compartmentalizing rock volumes into different groundwater regimes, and possibly different geothermal gradients: Mapping their distribution and orientation of faults therefore is important for developing an accurate hydrogeologic model of the region. Supporting data, such as existing published geological mapping, airborne gravity/magnetic data and results of field mapping will be integrated to improve and provide control for the final map interpretation. Total estimated cost for Task 1.2 is $45,000.

Task 1.3: Detailed Area of Interest Reconnaissance

A multidisciplinary program of detailed satellite investigation, airborne geophysics, air photo interpretation, field mapping and geochemical analyses is required to identify and assess the geothermal significance of geologic features at a local level. Purchase and processing of more detailed satellite imagery of the detailed study area will allow for detailed geologic assessment at a local level. While the methods of processing and interpretation are the same as for the regional bedrock mapping and correlation of heat flow measurement locations, the data used are different. For meter-scale observation, Quickbird or IKONOS imagery should be acquired. This imagery will provide recent coverage of the detailed study area that would permit 10,000-scale interpretation. IKONOS senses the visible (VIS) and near infrared (NIR) wavelengths. These data do not however, have thermal infrared sensors, only infrared, so heat cannot be measured. The data do provide pseudo-natural color images and the bandwidth of the sensors is much broader with associated spectral discrimination. The increased spatial resolution allows far more detailed geomorphological and by association, lithological discrimination. The response of gamma radiation from basement granites would most likely be effectively shielded by the overburden and basalts. Heat detection also would probably be obscured by the high density of smokestacks in the survey area. Therefore an aeromagnetic survey should be considered to interpret and delineate subsurface structure. A high-resolution aeromagnetic survey can be used for the detection and detailed mapping of faults and fractures throughout the sedimentary section. The data also can be modeled to evaluate depth to bedrock, basement structure, and lithology. Fugro anticipates that the aeromagnetics analysis will be complicated by the large number of man-made features in the area and the presence of the buried basalt layer (usually highly magnetic), which may mask the structure of the underlying rock. The initial subtask proposed prior to design and implementation of the airborne survey is to compile and interpret publically available, regional US Geological Survey magnetic data. This dataset, while coarse, should provide insight into whether an airborne survey will provide sufficient resolution to image bedrock and associated structure beneath the Holyoke Basalt.

Fugro's cost estimate is based on a survey area flown on a regular grid basis with lines spaced at 500 meters and control lines at 2,000 meters for a total of 4,500 kilometers of survey flight lines. The airborne survey equipment typically includes a magnetometer with digital recording via a portable computer. GPS receivers with the magnetometer operated in parallel throughout the airborne data acquisition ensure continuous monitoring of magnetic diurnal activity and GPS-based accurate locations. The product of the survey would consist of processed Digital Grids, suitable for imaging. A calculated magnetic derivative grid would be provided along with an interpretative map and data report.

Interpretation should include a qualitative and quantitative review of all profiles and maps to produce a geological interpretation showing wherever possible the depth to basement, geological contacts, and faults. The effect of near-surface cultural features should be filtered out to minimize the effect on the interpretation of basement geological structure. The presence of basalts in the section will complicate the interpretation of the topography of the basement surface as the magnetic susceptibilities of the basalt will generally be higher than the susceptibility of the granitic crystalline rocks. However, the aeromagnetic data should provide a depiction of fault locations and the subsurface distribution and general lithology of crystalline bedrock beneath the Hartford basin, including the likely depth and extent of the buried Belchertown intrusive complex that can be used for siting exploratory geothermal gradient wells.

Airborne data collection would require several weeks to obtain the necessary permissions and position the appropriate aircraft. Permit costs are included in this estimate. The survey could be completed in a day with processing of the data requiring up to sixty days. Total overall estimated cost for Task 1.3 is $185,000.

Task 1.4: Detailed Field Reconnaissance

Geologic mapping should be performed to field check the interpretations from our desktop study and data collection described above. Prior to field mapping, available stereo-paired aerial photographs covering the area of immediate interest should be obtained and interpreted. A 10-day field campaign is estimated that would apply standard field mapping techniques to check bedrock geology, stratigraphic contacts, and the validity of our preliminary desktop-based data interpretation. Field reconnaissance should be performed by geologists familiar with the regional geologic setting, including examination of locations of known elevated heat flow, and of the local area of interest. In conjunction with the compilation of existing data, the field reconnaissance should be used to refine the regional bedrock geologic and structural map and develop maps of the local area of interest for the purpose of identifying drilling targets at site area at 1:6,000 scale. The maps of the site area would illustrate the distribution of bedrock geology and surficial geology.

Field reconnaissance would be conducted to verify interpretations of aerial photography, resolve ambiguous stratigraphic contacts, reconcile differences in delineation of map units among compiled datasets, perform detailed studies of critical features and relationships, and evaluate stratigraphic and structural relations. Existing data would be supplemented by collecting bedrock information in order to categorize relative stability characteristics of foundation materials and provide foundation design parameters. A portable spectrometer can be used to further analyze bedrock mineralogy at representative outcrops and exposures. The spectral reflectance characteristics of different lithologies, vegetation types and alteration zones near mineral occurrences can be measured using a GER3700TM portable field spectrometer. Detailed rock mass characterization and quantification, required for estimation of drilling properties, can be performed by visual inspection, hammer rebound testing, and measurement of discontinuities. Field estimates of rock block compressive strength should be made for each rock type by hammer rebound and scratch hardness testing. Where appropriate and relevant, data would be collected on rock mass structural discontinuities including fracture orientations, lateral extent (continuity), fillings, and roughness characteristics.

The field mapping effort is estimated to require two weeks for two geologists, with accompanying per diem and other supporting expenses including rental of a portable field spectrometer. Products of the field mapping should include draft geologic maps with GPS track logs showing areas of field reconnaissance with key sample locations and other direct observations. We estimate a cost of approximately $25,000 for this task, including purchase of aerial photography, expenses as described above, and field labor.

Task 1.5: Seismic Data Acquisition

Subsurface imaging of the area beneath the potential EGS site is critical to evaluating the thickness of overburden, depth to granitic rock, and the possible location(s) of basement faults and existing fracture systems – if such features can be imaged. Our cost estimate includes three lines (13 miles total), including two (2) 30,000-ft-long and one (1) 10,000-ft-long reflection and refraction profiles (based on a 10 ft station interval), along with velocity tomogram and depth migration. The total number, orientation, and length of individual lines would be dependent upon the final area of interest and proposed footprint of the EGS facility. Our total cost estimate for seismic data collection, processing and interpretation is $375,000.

Task 1.6: Exploratory Drilling

Thermal resources are most precisely located and characterized by identifying the geothermal gradient associated with them. This can be done by drilling cost-effective 'slim-line' holes using a conventional rotary drill rig. The level of thermal heat flow can be measured well above a potential resource and the temperature at depth can be calculated using the geothermal gradient observed in the drill hole. This requires drilling boreholes to depths between 1,500 to 1,700 feet. Installation of three-inch diameter well casing then allows completion of the borehole similar to a standard water well, allowing accurate downhole temperature gradient values to be measured.

The shallow test well has to be sufficiently deep to evaluate the geothermal gradient, measure down-hole rock thermal properties and allow well-bore logging for stress analysis - enabling modeling of the reservoir potential. Also, rate of penetration (ROP), which is controlled by geology and bit selection, should be carefully collected as ROP governs rotating drilling costs. For direct evaluation of the subsurface rock types, associated mineralogy, and discontinuities such as faults and fractures, continuous coring techniques are required to obtain relatively undisturbed rock samples for laboratory analysis.

It is anticipated that standard rotary wash drilling techniques (HQ wireline and/or dry core method) will be used when drilling in soil and standard rock coring methodology will be used to drill in hard bedrock. Geologic classification of overburden and bedrock material will be logged in accordance with the Unified Soil Classification System (USCS, ASTM D2487-93) and rock descriptions, including discontinuity description, will be based on procedures by Brown (1996) and Hoek (1996).

Prior to any subsurface exploration, a field reconnaissance would need to be performed to mark the locations of planned boring. In order to avoid buried utilities and to comply with state law, the Underground Service Alert should be notified of planned boring locations. Town, county, and state drilling permits should be obtained as necessary and these estimated costs have been factored into the overall cost estimate.

A minimum of eight (8) geothermal gradient (1,500-1,700 foot deep) boreholes are required within targeted area of interest. For exploration, based on an overall minimum production rate of ±6 linear feet per hour and roughly 1,600 linear feet of drilling, we estimate 30 to 35 days of drilling would be required per boring. We estimate drilling, geologic logging, and heat flow measurements will require approximately $80,000 for drilling and an additional $30,000 for logging and measurements per borehole, for a total estimated cost for drilling of $880,000. An additional three (3) shallow (<300 foot depth) costing approximately $75,000 are required for geotechnical sampling and seismic network installation outside the area of interest. Three (3) deep (6,000 foot depth) are required for final characterization of the specific location of interest. These boreholes consist of completed wells (5-1/2" or 7" casing and cemented). We estimate drilling, geologic logging, and heat flow measurements will require approximately $160,000 per deep borehole, for a total estimated cost of $480,000. If the boreholes are not completed as wells containing seismic monitoring equipment, as proposed in Task 1.8, each hole would need to be grouted with neat cement at a cost of approximately $3-4/ft.

Additional assumptions include:

- No hazardous materials are encountered and cuttings are classified as non-hazardous.
- The site will include a secure staging area for drilling equipment, field supply storage, and to house barrels until pickup for disposal.
- No Site Security is required.
- No restriction of working hours, assuming 9-hour workdays Monday through Friday.

Task 1.7: Downhole Geophysics/Packer Tests/Laboratory Testing

Downhole wireline logging, consisting of caliper, flow meter, and video logging, should be performed through the entire open hole interval of the well following the development of the new well. Optical televiewer logging should be performed along with the suspension logging. The use of this logging tool is especially useful if core recovery is poor, and also provides a means for having a hard copy of the borehole wall features and a quantification of the features in terms of fracture frequency with depth and fracture orientation. Typical downhole geophysics range from $5,000 to $10,000 on the shallower wells to $15,000 per deeper hole for a total estimated downhole logging cost of $125,000.

We assume that a minimum of one pump test per boring is required, using packer testing to isolate and characterize groundwater flow within the shallow subsurface. Tests to be conducted include pressure pulse testing, pump testing, and constant head injection testing. We anticipate approximately four (4) hours per boring is required with a total minimum estimated cost for downhole groundwater flow (packer) testing of $10,000.

Laboratory testing of representative samples obtained from the boreholes should include material strength tests, petrographic and X-ray diffraction classification of rock samples to determine the chemical/mineralogic composition of subsurface materials, materials, hydrogeochemical sampling and analyses; and geothermometry determinations. Samples should be reviewed by senior geologists/engineers to select those most suitable for testing. Based on our experience, we assume that 25% of the total testing budget is required to adequately supervise the laboratory testing program. Successful management laboratory testing requires constant communications with the testing facilities for discussion of multiple and sometimes very complex details of the requested testing program, including: a) sample replacement, which is very common when soil samples are not undisturbed, or rock core specimens are not suitable (too short, too fragmented, etc.); b) alternate testing methods become necessary, depending on actually encountered subsurface soil and rock conditions; c) testing replacement to meet the project schedule, when a specified piece of equipment is not longer available; and numerous other common testing issues/problems; d) producing periodic progress letter reports; invoicing; communications (teleconferences, etc.).

Soil and rock strength and behavior testing is anticipated to include unconfined compressive strength and unit weight testing of recovered rock core. We anticipate approximately $40,000 for general and specialized laboratory testing.

Task 1.8: Seismic Monitoring Array Installation

Installation of a seismic network is required to monitor pre-development seismicity, develop a three-dimensional velocity model for the geothermal reservoir, and evaluate stress changes in response to fluid injection and development. A downhole twelve station digital seismographic network should be installed using three-component borehole seismometers to meet the project monitoring objectives. Borehole seismometers would be installed at nominal 6,000 ft depths in three deep exploratory wells to ensure detection of the smallest earthquakes at the highest-possible frequencies to maximize earthquake location and focal mechanism resolution. Installation of the three 6000-ft borehole instruments ensures first-order 3D location capabilities using S-P times even if shallower stations do not provide additional constraints. Eight borehole seismometers would be installed at 1,500 to 1,600 ft depth in temperature gradient wells to ensure a sufficient distribution of stations with high signal-to-noise to provide well constrained earthquake locations in combination with the three 6,000-ft-deep borehole stations for the entire reservoir region.

Three near-surface stations, preferably installed in >300-ft-deep boreholes in rock, would be located outside the project operational footprint to provide clear earthquake location constraints to differentiate between local project induced seismicity and natural background seismic occurring outside the project area. The three deepest borehole stations will record the smallest earthquakes and provide triggers to perform beam forming stacks of the entire network in real time to detect and locate earthquakes smaller than would be detected by conventional processing. The design, installation, operation, processing, and analysis of local borehole seismographic networks for geothermal and induced seismicity applications require specialized expertise and ongoing maintenance. The system should include real-time processing and analysis of earthquake and ambient noise data to produce timely reporting of seismic activity. Assuming the temperature gradient wells are drilled first, the eight 1,600'-ft-deep borehole seismographic stations should ideally be installed initially to record continuous noise and drill bit noise from subsequent drilling and use these data with seismic interfereometric processing methods to produce pre-injection three dimensional P- and S-wave velocity models for the reservoir region.

The three-dimensional velocity model will ensure that accurate earthquake locations and focal mechanisms are obtained from the time of first injection to support monitoring of fluid injection, fluid flow, and pressure and stress changes within the reservoir in response to injection and production. We estimate installation of the downhole seismic monitoring array to cost approximately $1.28 million with an annual operating cost of $166,000 for maintenance, ongoing seismic data collection, and analysis.

Task 1.9: Induced Seismicity Hazard Evaluation

Development of a defensible assessment of the seismic hazard and risk associated with hydroshearing operation required to develop an EGS reservoir consists of: (1) evaluation of Baseline Seismic Hazard to the closest community, (2) estimation of the potential increase in seismicity rate, and the maximum likely magnitude of an seismic event induced by hydroshearing, and (3) evaluation of the increased seismic risk to the community imposed by the planned hydroshearing activities. Baseline Seismic Hazard is defined as the probabilistic seismic ground-shaking hazard from natural tectonic deformation before the onset of injection activities. Determining the Baseline Seismic Hazard requires a probabilistic seismic hazard assessment (PSHA) similar to that conducted for critical facilities. However, we believe it is appropriate to use results directly from the USGS National Seismic Hazard maps as the basis for evaluation of the Baseline Seismic Hazard case. This will eliminate the time and effort required to develop an entirely new regional source model, and will also forestall the comparisons between the USGS model to an in-house developed model that will inevitably be made in the public arena.

The next step would be to model the EGS stimulation well(s) as a discrete seismic source, based on the depth and volume of hydroshearing required for reservoir development. It would then be possible to incorporate this "new" source into the Baseline Seismic Hazard model to estimate the change in hazard due to the EGS stimulation at nearby communities based on population density. The change in hazard should be expressed in terms of the increase in felt effects from ground shaking at these sites (e.g., the increase in number of earthquakes producing given level of Modified Mercalli Intensity shaking over a specified period of time). This approach would provide quantitative engineering descriptions of probabilistic ground shaking hazard, as well as descriptions of the shaking hazard expressed in terms readily understood by the public and communicated in EIR documentation. We estimate that this task would cost approximately $40,000.

Task 1.10: Data Analysis/Reservoir Quantification

Based on all mapping, structural, geochemical, and geophysical data obtained in previous tasks, the following questions about possible buried heat sources in the local study would be addressed:

1. Can the documented locations of elevated heat flow in the region be correlated to similar rocks in the South Hadley area?
2. What is the likely subsurface distribution and structure of crystalline rocks that are potential sources of elevated heat?
3. Where are the best locations to drill production boreholes in the study area? What are the rocks at depth and how would the subsurface stratigraphy and regional stress regime influence additional, deeper drilling methods?
4. Based on the exploratory boreholes and seismic data, are there reasonable elevated heat values within economically feasible drilling depths and is there an existing fracture network that could be enhanced for installation of an EGS reservoir?
5. What are the induced seismicity hazards associated with any hydroshearing operation?

Because all map and data products would be georeferenced and incorporated in the GIS database developed for this project, it should be possible to directly compare all data sets, including gravity, magnetics, and regional geologic mapping. In addition, because opening fractures at depth is the preferred method for creating a reservoir for geothermal resource development, the regional stress regime is a controlling factor that should be integrated in drilling strategies. In opening fractures, the most favorable approach is one where the fractures are developed along the direction of maximum shearing stress. It therefore is important to have information on regional stress direction and magnitude in the planning of EGS geothermal development and development of a hydro-fracturing plan. As part of the review, sources of information on stress orientation such as the World Stress Map database to assess the state of stress in the study area. We estimate that this task would cost approximately $50,000.

Task 1.11: Final Report

Following the field investigation and analysis, a full Technical Report that summarizes the results of the investigation and integrates the findings of the literature review, aerial photographic analyses, satellite-based mapping, geophysics, field mapping, and drilling is required. The report should include interpretation of all available compiled and collected data, geophysical data including seismic reflection/refraction records with interpretation, borehole geologic and geophysical logs, evaluation of the geothermal resource, and recommendations for resource development. Project management and meeting costs are included in this task. We estimate that this task would cost approximately $75,000.

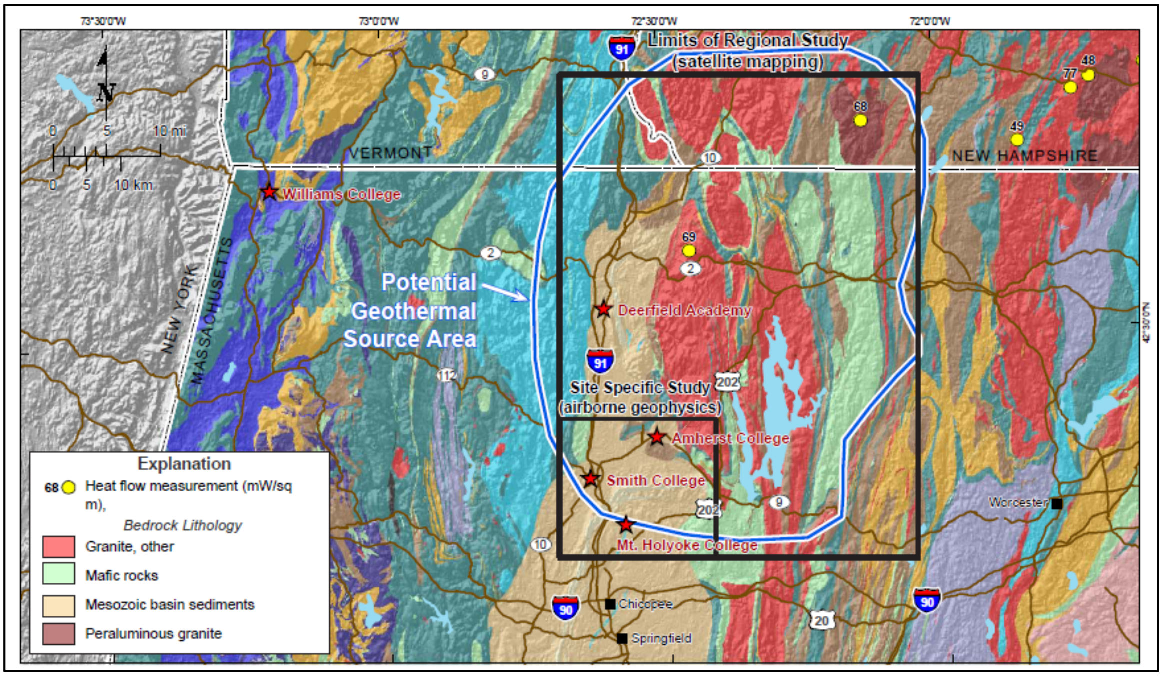


Figure 6: Bedrock Lithology of Western Massachusetts

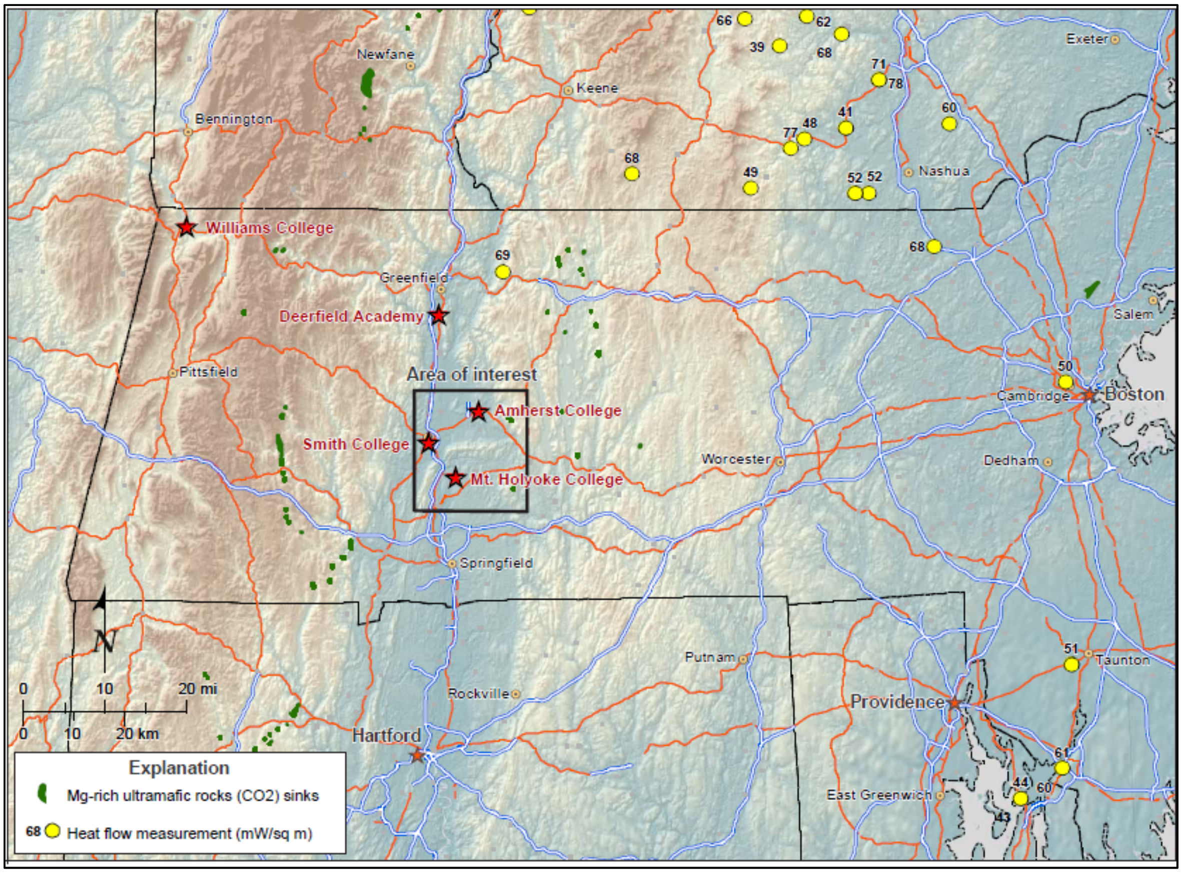
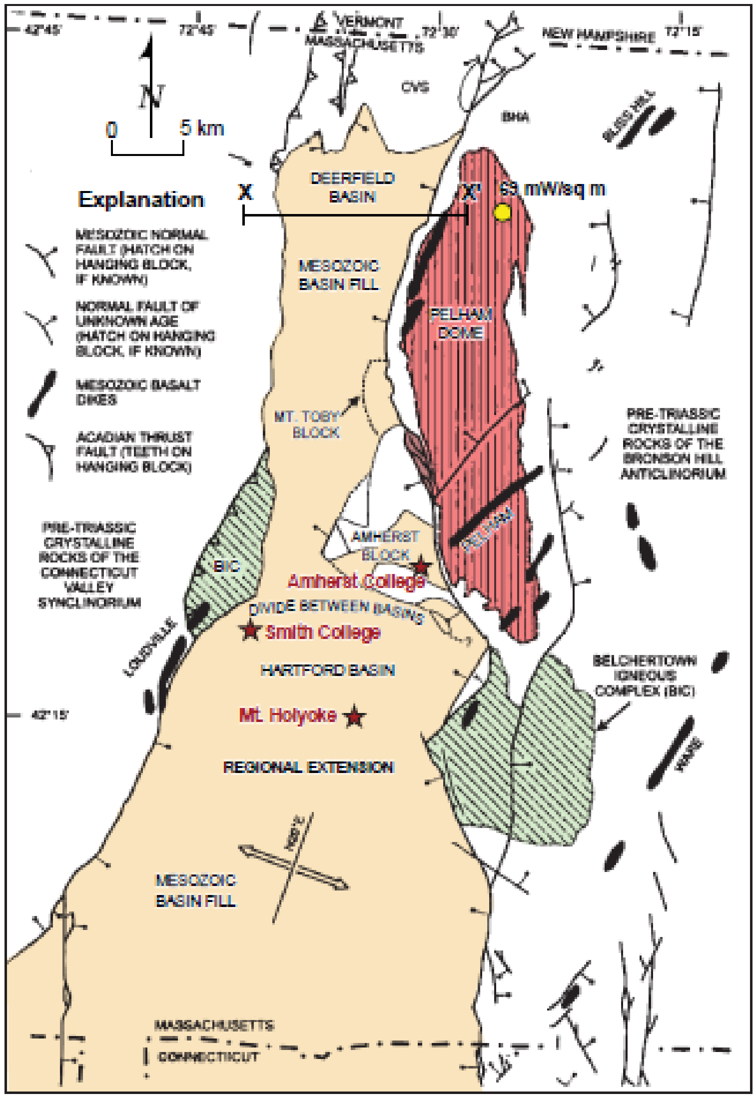


Figure 7: Regional Heat Flow Measurements and Ultramafic Rock Outcrops -- Carbon Dioxide Sinks



From Walsh, 2008

Figure 8: Generalized Geologic Map of Mt. Holyoke College Area

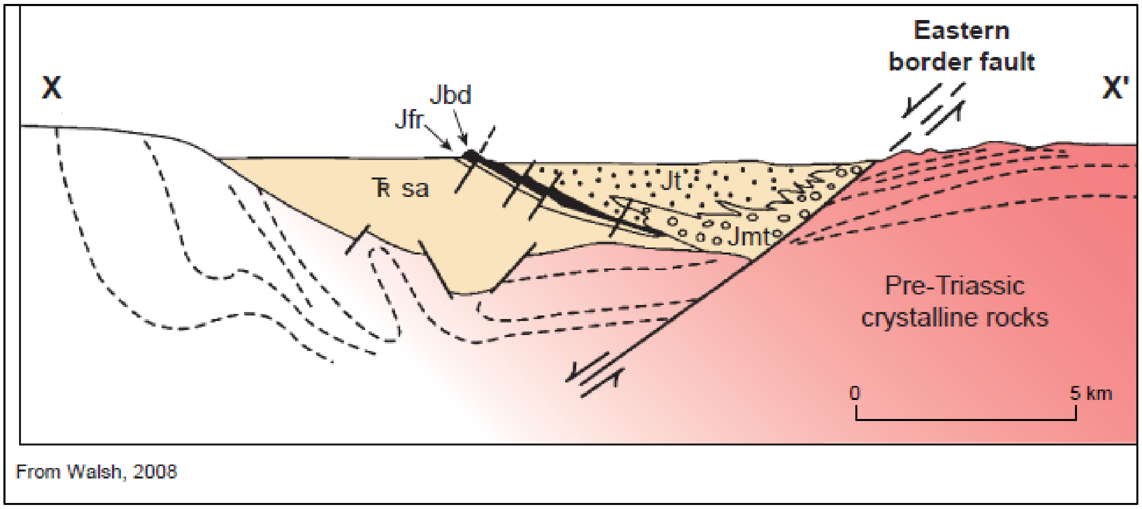


Figure 9: Representative Geologic Cross Section North of Mt. Holyoke College Area

WBS 2 - Reservoir Development

WBS 2 provides a reservoir design, well design and associated cost estimates for the EGS systems. Geothermex was selected for the Reservoir Design task, and Impact Technologies was selected for the Well Design Task.

There are two versions of WBS 2 created for the Water EGS at Westover AFB corresponding to two different project configurations:

1. Geothermal system sized at 70 MW gross, 50 MW net, consisting of electric drive water pumps using power produced by the geothermal project, and
2. Hybrid geothermal system sized at 50 MW gross, utilizing water pumps driven directly by natural gas burning "dual fuel" diesel engines, or indirectly from natural gas burning "dual fuel" diesel generators.

The net result is that the total reservoir development costs for the 70 MW gross and 50 MW gross water EGS systems at Westover AFB are approximately $900 and $700 million respectively. The table below is a breakdown of the costs for reservoir and well construction:

Table 3: Cost Summary for WBS 2 – Reservoir Development, SOPO 1

WBS	70 MW Gross		number	unit cost ($)	unit
2.0	**$890,540,446**	**Reservoir Development**	**Learning Curve**		
			Mult Fac	**# @ 91**	**# @ 82**
2.1	**$1,000,000**	Reservoir Planning	**0.837**	**3**	**13**
2.2	**$1,000,000**	Reservoir Model Development (integrate test bore results)	**0.831**	**3**	**22**
2.3	**$361,681,079**	Injection Well Drilling	**16**	**$27,011,283**	/well
		Large Bore, Steel, 21KFt			
2.4	**$460,659,367**	Production Well Drilling	**25**	**$22,179,074**	/well
		Small Bore, Steel, 21KFt, $20,179,074 plus $2M dual completion			
2.5	**$32,000,000**	Hydraulic stimulation	**16**	**$2,000,000**	/well
2.6	**(included)**	Intangible Drilling Costs (Mud / Temporary Equipment / Removal)			
2.7	**(included)**	Special Sand / Fluid Injection (Hold Fractures Open)			
2.8	**(included)**	Special Sealing Fluid Injection (probably more for CO2 system)			
2.9	**$15,000,000**	Production pumps	**25**	**$600,000**	/well
2.10	**$6,000,000**	Specialized logging	**8**	**$750,000**	/well
2.11	**$6,000,000**	Coring and leak-off testing	**8**	**$750,000**	/well
2.12	**$4,100,000**	Post-completion testing	**41**	**$100,000**	/well
2.13	**$3,000,000**	System circulation testing prior to plant start-up	**4**	**$750,000**	/module
2.14	**$100,000**	Water Well Drilling	**4**	**$25,000**	/well
WBS	**50 MW Gross**				
2.0	**$699,109,235**	**Reservoir Development**	**Learning Curve**		
			Mult Fac	**# @ 91**	**# @ 82**
2.1	**$1,000,000**	Reservoir Planning	**0.843**	**3**	**9**
2.2	**$1,000,000**	Reservoir Model Development (integrate test bore results)	**0.834**	**3**	**17**
2.3	**$273,084,071**	Injection Well Drilling	**12**	**$27,011,283**	/well
		Large Bore, Steel, 21KFt			
2.4	**$369,725,164**	Production Well Drilling	**20**	**$22,179,074**	/well
		Small Bore, Steel, 21KFt, $20,179,074 plus $2M dual completion			
2.5	**$24,000,000**	Hydraulic stimulation	**12**	**$2,000,000**	/well
2.6	**(included)**	Intangible Drilling Costs (Mud / Temporary Equipment / Removal)			
2.7	**(included)**	Special Sand / Fluid Injection (Hold Fractures Open)			
2.8	**(included)**	Special Sealing Fluid Injection (probably more for CO2 system)			
2.9	**$12,000,000**	Production pumps	**20**	**$600,000**	/well
2.10	**$6,000,000**	Specialized logging	**8**	**$750,000**	/well
2.11	**$6,000,000**	Coring and leak-off testing	**8**	**$750,000**	/well
2.12	**$3,200,000**	Post-completion testing	**32**	**$100,000**	/well
2.13	**$3,000,000**	System circulation testing prior to plant start-up	**4**	**$750,000**	/module
2.14	**$100,000**	Water Well Drilling	**4**	**$25,000**	/well

Reservoir Design

The reservoir design was developed based on the average of limited known data on actual heat flux in the surrounding area of Western MA. This, plus knowledge of the environment from WBS 1 resulted in the baseline design temperature gradient of 1.21 deg F per 100’ of depth. Based on a temperature gradient of 1.21 deg F per 100’, wells of 20,000 ft result in 308 deg F bottom hole temperature; 30,000 ft wells result in over 400 deg F at depth.

Thermal analysis of topside equipment, initially performed by Geothermex and validated by GEECO and Turbine Air Systems suggested that approximately 30,000 gpm of flow would be required to produce 70 MW. The required water pumping power is 20 MW assuming a production index of 1 gpm/psi, as summarized in the spreadsheet below prepared by GEECO. Geothermex and TAS both provided similar calculation models that agree with the GEECO model, using slightly different assumptions for pumping power, component efficiencies, and the production index. A baseline flow of 31,250 gpm (4000 lbm/second total flow) for 70 MW Gross system was selected using the results of the three models, and is consistent with a nominal 7% cycle efficiency of ORC (that uses R134A refrigerant as a working fluid) at 287 deg F turbine inlet temperature.

Table 4: Thermodynamic Model for 20,000 feet Water EGS in Western Massachusetts, SOPO 1

Assumptions:									
Surface Temperature =		66	(deg F yearly average)						
Temperature Gradient =		1.21	deg F / 100' (1.21 deg F in Subir Report)						
1000 psia injection pressure (for calculation purposes); would actually have lower injection pressure, but with production pumps									
70 MW Fixed Power (Gross). 50 MW Net. Subir Flow Rate: 31,250 gpm total. TAS Flow Rate: 27,280 GPM at same power level									
Hot Side HX Exit Temperature =			125.00	deg F					
Down Hole (Injection Temperature) =			125.00	deg F					
Results:			31250	GPM	Earth Heat Extraction Rate			2488.2	MMBTU/hr
Massflow (Fresh Water Density)			4000.6	LBM/SEC	Gross Power			69.6	MW
Hot Side HX Heat Rate=			2509.9	MMBTU/hr	Pump Power			19.6	MW
			986612	hp	Net Power			50	MW
			736.0	MW	Required Topside System Cycle Eff.			6.8%	
					Required "Earth" Cycle Efficiency			6.9%	
					(earth heat removed vs. electric power produced)				
Fluid: (no mixtures in this version)				REFPROP Unit Call (Leave variable as E)					
water				Unit system:	E				
Pressures Shown due not include surface piping or well pipe pressure drop									
					Productivity Index =		1.00	gpm/psi	
Total Flow =		31250	gpm		Pressure Drop Inj to Production =			1200	psi
N Wells=		25	(production)				(@ Bottom)		
Per Well Flow =		1250	gpm		Total Pumps Delta Pressure (Production Plus Injection)				
					907	psid	(300 psig, plus psid top)		
Increment =	1000	ft per calculation			Notional Power				
					23627	hp (total pumps)	20	MW Pumping	
Bottom Density @ Bottom Temperature =			59.2						
			Injection Wells				Production Wells		
Calc Step	Depth		Temp (Inj)	Density (down)	Injection Well	Temp @ Depth	Temp Up	Pressure	Density
	(feet)	(m)	F	(lbm/ft^3)	(psia)	F	F	(psia)	(lbm/ft^3)
0	0	0	125.0	61.8	1000	66	297.9	393	57.5
1	1000	305	125.2	61.9	1429	78	298.4	792	57.5
2	2000	610	125.4	62.0	1859	90	298.9	1193	57.6
3	3000	914	125.6	62.0	2289	102	299.5	1593	57.7
4	4000	1219	125.8	62.1	2720	114	300.0	1994	57.8
5	5000	1524	126.0	62.2	3152	127	300.5	2396	57.8
6	6000	1829	126.2	62.3	3584	139	301.0	2798	57.9
7	7000	2134	126.4	62.3	4016	151	301.5	3201	58.0
8	8000	2438	126.6	62.4	4449	163	302.0	3604	58.1
9	9000	2743	126.8	62.5	4882	175	302.5	4008	58.1
10	10000	3048	127.0	62.6	5316	187	303.1	4412	58.2
11	11000	3353	127.2	62.6	5751	199	303.6	4817	58.3
12	12000	3658	127.4	62.7	6186	211	304.1	5223	58.4
13	13000	3962	127.6	62.8	6621	223	304.6	5628	58.4
14	14000	4267	127.8	62.8	7057	235	305.1	6035	58.5
15	15000	4572	128.0	62.9	7493	248	305.6	6441	58.6
16	16000	4877	128.2	63.0	7930	260	306.0	6849	58.6
17	17000	5182	128.4	63.1	8368	272	306.5	7256	58.7
18	18000	5486	128.6	63.1	8806	284	307.0	7665	58.8
19	19000	5791	128.8	63.2	9244	296	307.5	8074	58.9
20	20000	6096	129.0	63.3	9683	308	308.0	8483	58.9

In the model shown, 1200 psi is the assumed pressure drop through the rock. It is further assumed that there is a weak thermal siphon, and therefore the required pumping power is based on a total pressure difference of 907 psi. For calculation purposes, an injection pressure of 1000 psi is used and the production pressure (unpumped) is still high enough to prevent boiling. In reality, a lower injection pressure would be used, and additional pumping power would be via electric production pumps, located at about 3,000 ft depth in the producer wells. Note that the well designs, to be discussed later, have large casing diameters at this depth to support these production pumps. Large injection pumps would still be required – though injection pressures would not be 1,000 psi, they would still be significant.

The bullets below and graphics to follow provide the details of the design of the reservoir:

- Based on heat flow measurements, the temperature gradient in the area is approximately 1.21°F/100 feet.
- Production wells are assumed to be cased to 20,000 feet vertical depth and have an open hole section of 1,000 feet below the lowest cemented casing.
- The production temperature of the wells is 308°F.
- Making certain simplifying assumptions about the nature of the stimulated EGS reservoir, the heat reserves are approximately equivalent to 13 MWe (net) per square mile of surface area. This is considered the maximum possible value that could be achieved.
- For a 50 MWe (net) project, 4 square miles of contiguous surface area and a stimulated volume of 111 billion cubic feet (3.1 cubic km) would be needed, at a minimum.
- Assuming a post-stimulation productivity index (PI) of 3 gpm/psi and a maximum production pump setting depth of 3,000 feet, 1,260 gpm of fluid at 308°F can be delivered to the surface at each production well.
- This is equivalent to a gross power capacity of 3.4 MWe per well, assuming a typical binary power plant. Considering the parasitic power need for the production pump, this is equivalent to a net generation capacity of 2.0 MWe (net) per well.
- Therefore, 25 production wells are needed for a project with a net generation capacity of 50 MW Net (or about 70 MW Gross).
- To minimize the length of the pipeline network to provide adequate heat transfer surface in the reservoir and to prevent rapid cooling of the produced fluid, a repeated 0.5 mile x 0.5 mile "5-spot" pattern, with one injection well surrounded by 4 production wells, is considered to be the best arrangement.
- 16 repeated 5-spot patterns are required, requiring 25 production wells and 16 injection wells, for a total of 41 wells.
- Each of the 41 wells need not be drilled from a different drilling pad. Because the wells are very deep, a large lateral reach can be achieved by directional drilling. Therefore, the 41 subsurface locations of wells shown in Figures 6 and 7 can be reached by directional drilling from far fewer drilling pads.
- A single, centralized power plant would require unduly long and a somewhat complex pipeline network. Therefore our conceptual layout assumes four - 12.5 MW (net) power modules (one per square mile); this scheme will also allow maintaining a higher plant capacity factor than would a single 50 MW (net) plant.
- Based on this layout, and assuming that each well is drilled from a different pad, we estimate total production and injection pipeline lengths of 12.4 and 5.7 miles, respectively. Terrain and other restrictions will increase this length; we have arbitrarily assumed a 20% increase, yielding 15 and 7 miles for the production and injection piping systems, respectively. However, the pipeline network can be minimized by drilling several wells from a given pad, such as, one or two pads for production wells and a pad for injection wells per module.

- The total flow rate that would need to be accommodated by any section of (insulated) production pipeline is 1,260 gpm. Each segment of uninsulated injection pipeline would need to handle 1,970 gpm.

In summary, the Geothermex System Design consists of 25 producer wells and 16 injector wells for the first geothermal system configuration sized at 50 MW net, 70 MW gross. The 50 MW gross geothermal system has the identical field layout of the 70 MW gross system, but with one row of producers and injectors removed. There are 20 producer wells and 12 injector wells for the 50 MW gross system. The graphics below show the well and surface system layouts for 70 MW Gross Water EGS system.

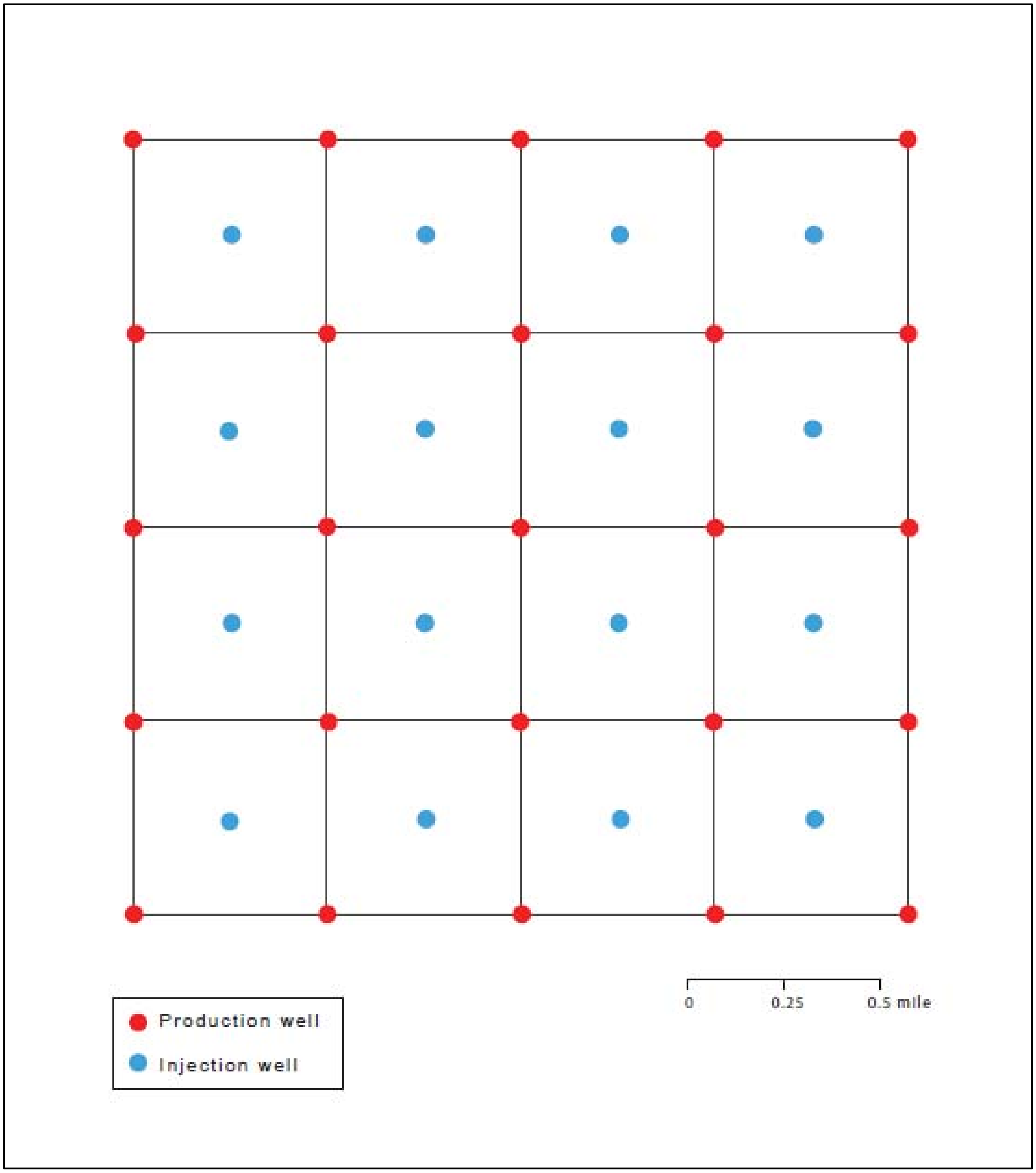


Figure 10: Proposed Well Configuration for 70 MW Gross Water EGS Project in Western Massachusetts

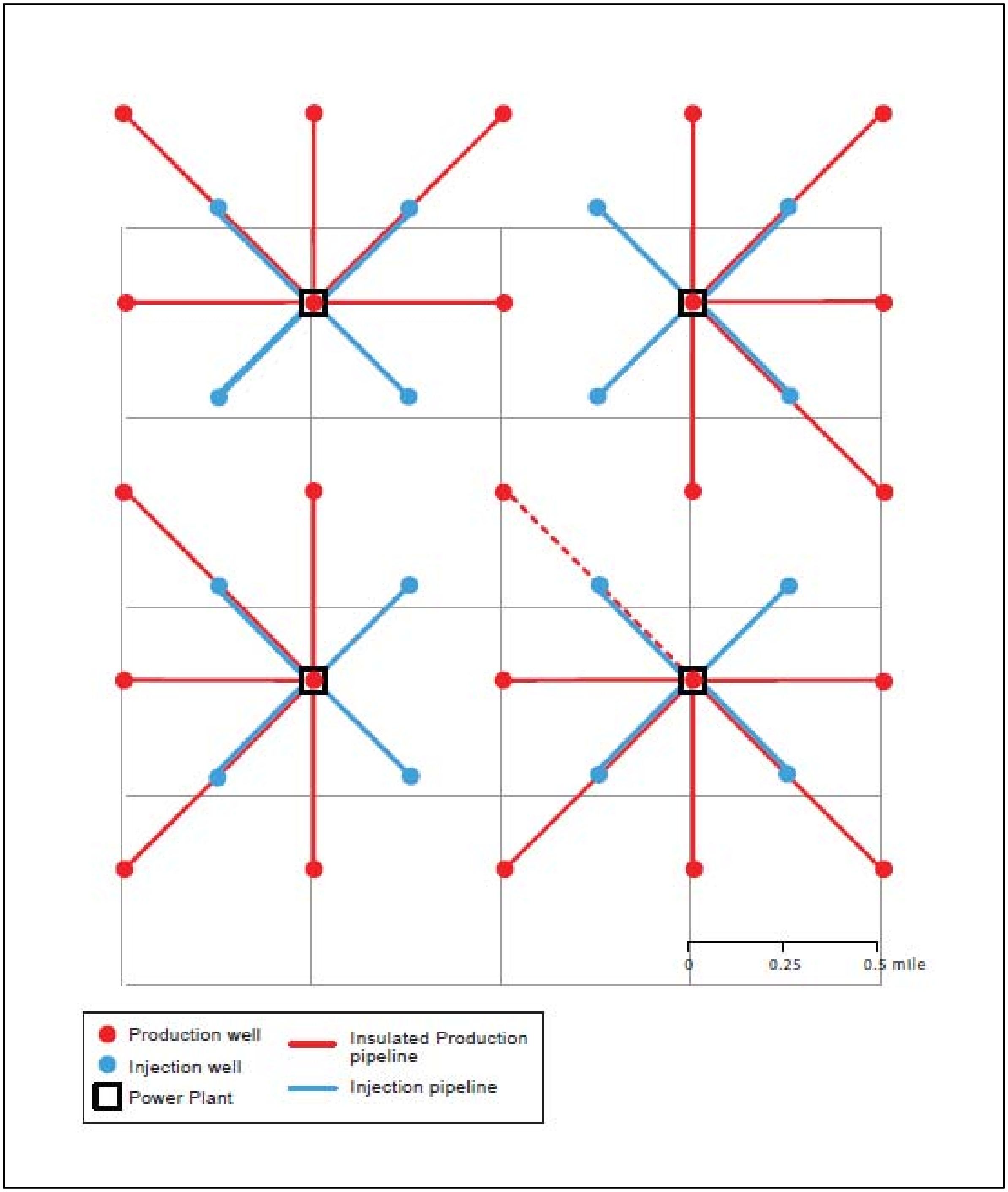


Figure 11: Proposed Surface Facilities for 70 MW Gross Water EGS Project in Western Massachusetts

Well Design

Using the Geothermex reservoir design for the 70 MW gross and 50 MW gross geothermal systems, Impact Technologies designed and provided cost estimates for both 8” and 10” nominal open hole wells.

Furthermore, Impact Technology's work effort included optimizing well depth by considering the following in coordination with Geothermex:

- drilling costs
- depth to top of the reservoir formation (thickness of sedimentary cover), and
- temperatures

Drilling-cost for both 21,000 foot and 30,000 foot designs were estimated. Two versions of these designs were performed to allow different final bottom hole diameters, 7-7/8" and 10-5/8" diameters. The results of this effort are summarized below. Note that these estimated costs are without contingency. Authorization for Expenditure (AFE) type cost estimating details are provided below.

Because these depths are outside the bounds of conventional geothermal (and even most all O&G) drilling, some disclaimers, background, explanation and description of the well costing process and discussion of limitations/ concerns are necessary. Foremost, this is not an exhaustive study with ready to drill well designs. Much more information must be obtained with a full engineering and costing study to come up with a final well construction design prior drilling. In addition, many of the well components required for drilling such wells have very-very long lead times.

Reservoir Development Background

Impact Technology's reservoir development effort consists of engineering the reservoir to obtain sufficient flow rate and heat transfer for efficient operation. Engineering for efficient operation is vital for minimizing the number of wells and improving the economics of the EGS operation. To do this, a flow path between the drilled injection well and the production wells is required. Hydraulic fracturing is considered the conventional method to develop the reservoir contact needed for efficient heat transfer between the injection and the production well. This path consists of an induced fracture deep in the earth extending out from one (injection) well which is then intersected by a directionally drilled bore of the second (production) well. Sometimes hydraulic fractures from separate wells can be connected, but this is risky since sufficient connectivity cannot be assured. It should be noted that the public and the US administration is concerned about hydraulic fracturing for potential environmental pollution and for induced micro-seismicity, even though hydraulic fracturing was started in 1947 and is widely used today.

Vertical Well Drilling Concept

The basic construction concept of a deep well is that a very large bore or hole (36" diameter, or more) is first drilled from the surface and down into the earth. When the desired depth is reached based on design (typically thousands of feet), a slightly smaller diameter steel casing is installed in that newly drilled hole from the surface down to the bottom depth. Casing is made up of many jointed, long (40 feet) steel tubes that are connected (screwed together or welded) to form a continuous pipe. Cement or grout is then pumped down the inside of the casing and circulated around the outside of the casing/pipe such that it fills the void between the drilled rock bore and the outside of the casing. The cement or grout is allowed to fully set, harden and form a seal.

Next, a slightly smaller drill bit (required to be smaller than the previously set casing internal diameter) is then lowered through the previously set casing and drills out the end of the open casing into the rock below, creating a new smaller bore (the size of the drill bit utilized). This new smaller hole is drilled to a new designed depth (typically thousands of feet) and an even smaller diameter casing is run and cemented in the well. This process is repeated until the total desired depth (and temperature for EGS applications) is reached. In many cases, this requires 3 to 7 casing strings that begin to resemble a telescope, decreasing in size as it descends down into the earth. Sometimes a casing string is run to the depth desired, but does not go all the way up to the surface, but instead, overlaps and stops at the previous larger casing string. This partial length casing string is called a 'liner' and is used for cost saving purposes.

The Well Cost Lite program, an Excel based spreadsheet program developed at Sandia National Laboratory, was used in the formulation of the geothermal well costs based on the criteria set and available cost data. The central factor driving the well cost estimates is casing design (materials, cementing, rig time for >50% of the total well cost), and because of the holes' great depths and large sizes, non-standard casing sizes are necessary. The cost estimates also assume that they are not an optimized casing design, the holes are relatively 'trouble free', incurring only minor lost circulation, mostly in the upper shallower intervals. Features that might be optimized in well construction designs are discussed in more detail below.

Well Design

The basic well design comes from the set hole size desired at the deepest depth and the limits on the casing string design. This design may be altered if, during the drilling phase, the process encounters multiple or severe drilling problems. There are three basic measures of casing's strength—collapse, burst, and tensile rating. This fundamental well design for these holes is based on collapse pressure—that is, the casing's collapse rating, especially in the deepest interval, must be enough to support the static pressure of an outside column of fluid reaching to surface, but with the inside evacuated.

Casing

Casing strengths were not de-rated for high temperature because none of the casing is expected to see temperatures above 450 degrees F.

Casing shipping costs were not increased due to the 'remote' EGS location because most pipe would be efficiently delivered near the site by ship- no matter the location.

Burst limit design will be primarily driven by the type of stimulation (e.g., hydraulic fracturing) and the stimulation pressure that must be applied to the formation. For EGS projects, stimulation pressures are relatively low (less than 5000 psi). Further design refinements will address tensile, burst, corrosion resistance and cost optimization. For example, a given casing string in the cost estimate is always taken to be constant weight and grade, but it is possible that this is not cost-optimum. In the upper part of the hole or even a given size casing section, a thinner wall might be used because the collapse pressure is lower, but this must be balanced with the necessity for greater tensile strength to support the weight of the casing string.

Note that for all casing over 20” diameter used in these estimates, the casing is assumed to be custom rolled and welded, that is, specially made. There are two principal consequences of the very large sizes for the upper casing strings: the steel stock must be rolled and welded to the design sizes, and the casing joints are welded, not screwed, together as the casing is run into the hole-on the rig. The latter step means that each casing connection will require approximately 2.5 hours welding time of the rig and crew.

1. Well design has assumed that many non-standard casing tubulars will be manufactured / developed by bending and seam-welding steel plate. It will be crucial to confirm the manufacturing capability of the supplier and to schedule this long in advance. The vendors who have manufactured drive piles and riser pipe in the Gulf Coast Region will be able to provide these “non-standard” welded pipes. The cost of shipping is not included in the welded casing cost. There may be manufacturers near the well site that can fabricate the rolled and welded casing.
2. The casing size necessary to provide clearance for an electric submersible pump set at 3000 foot depth was considered. The diameter of the centrifugal pump (given as fitting within a 16” casing by GeothermEx), and thus the cavity, will be dictated by the flow rate, head and horsepower, but the final pump specifications are not yet determined. The 300 degree F temperatures expected in this project are within the range of existing pump capabilities.
3. The use of high grade steel materials—P110, Q125, and V140—were needed to satisfy the burst and tensile loads on the casing. Proprietary casings, with enhanced collapse ratings, may be necessary instead of the more conventional API weights and grades. In more conventional (and shallower) geothermal casing designs, higher grades of casing are not commonly used, due to stress corrosion cracking concerns. An environment with high temperature CO_2, in the presence of water, will be even more severe due to the formation of carbonic acid- pitting corrosion attack. Special liners or alternative materials can be used if this will be a problem.
4. Optimized casing design (for the water EGS) will use the least expensive possible casing throughout. For example, if the weight of an entire casing string would dictate high-tensile-strength material at the upper part of the hole, then using liners and tiebacks to reduce the tensile requirements above may be cost-effective.
5. Where rolled and welded casing is used, the rig time will be minimized by welding two 40’ joints of casing into an 80’ length on the pipe racks, before the pipe is raised into the derrick. Separate time charges are included for welding the casing on the rig. An alternative approach is to use riser breech block connections, welded to the casing sections, for rapid makeup in the derrick. These couplings are very expensive and a cost/time tradeoff for their use, compared to welding, must be evaluated.

Other casing design assumptions:

1. The depth of sedimentary formations, where crystalline rock begins, was set at 10,000 feet for drilling performance and casing set point concerns (in Western MA).

Cement

1. Cement volumes have been calculated with 50% excess in the top 2 intervals, to accommodate possible lost circulation in those intervals. 30% excess is used elsewhere.
2. The use of foam cement (nitrogen foamed) and reverse foam placement may be used, where it is to our advantage.
3. Stage collars, liners and tiebacks will be used to minimize the hydrostatic head of the cement column, thereby reducing the collapse load.
4. Trapped water, especially in the annulus between two casing strings, must be avoided to prevent collapsed casing due to thermal expansion of the trapped water with temperature.
5. In the cases studied with carbon dioxide as a heat transfer medium, special carbonic acid resistant cements would be needed. These should be tested at the temperatures expected before being used.

Drilling

1. In the cost estimates, all the large hole diameters (above 26”) have been planned as drilling with a 17-1/2 or 26” bit, followed by one of more hole-opener runs to yield the needed diameter. Separate time charges are included for hole-opening.
2. List price has been used for conventional bit costs, but special diameter or special design bits are priced at 125% the list price of the nearest size conventional bit. On the deep casing designs, the ID or drift is often too small for the common next bit diameter.
3. There are two separate, but closely related, parts of preparing for a drilling project—planning the well and designing the well. “Planning” means to list, define, schedule, and budget for all the multitude of individual activities required to drill the well, and “designing” means to specify all the physical parameters (depth, diameter, etc.) that define the well itself. Preliminary planning and designing has been done just to prepare the cost estimates, but much more detail will be needed before the project is ready for spud. These details will be added during the “Prespud Engineering” item in the cost spreadsheet (approximately $300,000 for the 30,000-ft well.)
4. “Trouble” is a generic name for many sorts of unplanned events during drilling, ranging from minor (small amounts of lost circulation) to catastrophic (the BHA is stuck in the hole and the drill string is twisted-off). In some cases, experience in the same or similar reservoirs will give a hint that certain types of trouble are likely, but at other times events are completely unexpected. Because the first holes drilled in this project will be unique, no trouble cost (other than minor lost circulation) has been assigned to the drilling. Clearly, this may change with experience.
5. Bit performance (life and rate of penetration) for the cost estimates has been based on extensive history and experience in geothermal drilling. Sensitivity of total cost to changes in these values can easily be evaluated with the spreadsheet.
6. Costs for handling naturally occurring hydrogen sulfide (H2S) has not been specifically included. Some low level background levels are normally seen, but significant levels will required special equipment and safety procedures. Also, it should be noted that H2S is a dangerous gas that is

lethal at very low concentrations. It should be treated as a special hazard to the rig crew and the nearby public during drilling or normal EGS operation. In addition, it can cause severe corrosion of steels, leading to rapid failure. The special metallurgy for containing H2S has not been included in these cost estimates.

Drilling- Air Package

1. Liberal use of air packages, to produce aerated drilling fluids is included. This will help to overcome pressure balanced mud losses and improved drill rate.
2. Fuel cost for the air package is included in the hourly cost. Fuel cost is not insignificant for air compressors and boosters--one 900 hp compressor, at full throttle, will burn 54 gallons/hour ($189/hour).

Drilling- Directional

1. The top 3000 feet of each well is assumed to be vertical to allow for the production lift pump.
2. Directional drilling is included in the cost estimate because each well must reach its proper spatial location at depth (in this case, to intersect a natural or man-made fracture). The injection well will have a limited amount of directional work, but the production wells must be accurately steered to intersect the fracture clusters. Directional work will generally begin within the bottom 4000 feet of the well, unless surface offsets are required.
3. Although weight on bit affects rate of penetration in hard formations more than rotary speed, some motor runs are expected for straight-hole drilling as well as for the directional work. The improved rate of penetration sometimes offsets the increased cost. Motors will be used in sections where they either save money in straight-hole drilling or are required to control the well trajectory.

Hydraulic Fracturing

In this EGS fracturing process, fluids are injected down a well (in this case the injection well) at high rates and with sufficient pressure to fracture or part the rock starting at the well bore. As the fluid volumes are further injected, the induced fracture at the deepest perforation or open hole section grows in length and height to match the volume injected. In addition to pressure, the colder temperature of the injected fluids when encountering the hot EGS rocks may cause thermal expansion/contraction effects that may also influence fracture formation, if the fluids are injected at high enough rates. Such high rate injection has a cost in the number of high pressure pumps required for the job. If the rock has permeability (connected porous channels) that allows flow into the rock (matrix or natural fractures) some of that injected volume is lost and does not serve to grow the fracture. In the case of the deep EGS crystalline granite rocks expected in this project, this “leak off” volume during fracturing is expected to be very, very low unless natural fractures are encountered. Encountering natural fractures would be good for EGS reservoir development but may impact continued operating cost to replenish those lost injected volumes. Because of this low matrix “leak off” rate, regular or ‘slick’ fluids with minimal additives can be utilized lowering the cost.

During the fracturing process, monitoring by surface or shallow buried seismic recorders to determine fracture orientation is performed (cost not included in this estimate). The later production well(s) are then directionally drilled (cost included and discussed above) to intersect that induced fracture at some spatial position for maximum flow coverage. However, the balance of the risks between fully intersecting the fracture system with the resulting beneficial low pressure drop (i.e., low parasitic loads from the injection pump) and too much connection that short circuits the heat transfer process, always exists.

When the pressure is sufficiently high to maintain the fracture apart/ open, the local stress field may cause movement of each face, relative to the other. When the pressure is relieved and the part closes, any gap remaining (due to debris or ‘ill’ fit due to the shift) will be the flow channels desired for EGS operation.

Recovering the injected fracturing fluid, if it is not the heat transfer medium desired during normal operation, can be a problem due to potential inter-reactions with rock and high alloy steel. If the injected fracture fluid is a compressed, supercritical or liquefied gas (e.g., carbon dioxide, nitrogen, methane, propane, butane, etc.), lowering the pressure of this hot fluid can cause it to partially vaporize and easily flow back out of the reservoir. Unfortunately, it is too costly to capture and reuse the fluid in this case, unless it can be immediately reused in fracking another nearby well. If it is very hot water, the reservoir can be mostly unloaded if the pressure can be dropped low enough (limits of casing collapse design), however, even small amounts of water with carbon dioxide can cause steel, and maybe rock, interaction and corrosion problems. This high temperature, high pressure corrosion concern was researched via the OnePetro searchable database (multiple disciplines) with many finds. However, it was beyond the scope of the study to evaluate these findings. If such research has not already been done, then CO_2 & water /water vapor inter-reactions at EGS conditions with steel alloys and granitic minerals should be fully researched.

Costing for typical high volume, low pressure (less than 5000 psi and typically nearer 3000 psi) slick water hydraulic fracturing on the completed injection well is provided at $1,500,000. The cost for a similar size hydraulic fracture using CO_2 is estimated to be up to $3,000,000 due to the special tank storage, pumping and safety requirements.

Reservoir Sealing

Methods to reduce short circuiting of the flow path between the injection well and the production wells which results in lower heat transfer, lower surface temperatures resulting in lower system efficiency can be accomplished by mechanical means in the well bores, chemical means in the out in the fractures or a combination of both. Also, continued loss of the heat transfer medium via consumption/ chemical reaction or leakoff through natural fractures or matrix permeability (not expected in the selected EGS reservoir) may be detrimental to the continuing operating cost of the system. The word “may’ is used since chemical consumption of the medium, if CO_2, can be seen as a carbon sequestration benefit with recurring revenues. However consumption due to chemical reactions brings up precipitation concerns of the reactant products once equilibrium of the system is changed, such as the flow moves from the hot EGS reservoir up the cooler production wells. Only fracture leakoff will be considered in this section.

In particular, mechanical isolation or choking of flow rates within the vertical or directional injection or production bores is not normally possible since cemented/ sealed casing is not normally used. In open hole sections (or even with uncemented slotted/ perforated liners) mechanical isolation can be accomplished by filling the hole from the bottom to some higher depth with impermeable material (like cement). Open-hole packers cannot be used due to the effect of high temperature on the elastomers of such downhole tools. Even then only mechanical wellbore isolation between fractured sets, and NOT within a fracture set, would be possible.

Selective plugging or sealing of high volume flow and leak off paths within the fractures are being researched by Impact and partners. Selective sized silica powder, silica nano-particles, high temperature resistant polymers, inert plugging agents, specialized SPI gel systems, and other materials are being studied in the literature and from industry. The problem is in not over plugging the high flow path, or to not accidently and detrimentally affect lower flow paths while treating the high flow paths. This is probably a key area for further EGS research.

Westover AFB Water EGS Well Design

Two well designs were developed for the water EGS at Westover AFB (SOPO 1). Those well designs are shown graphically below.

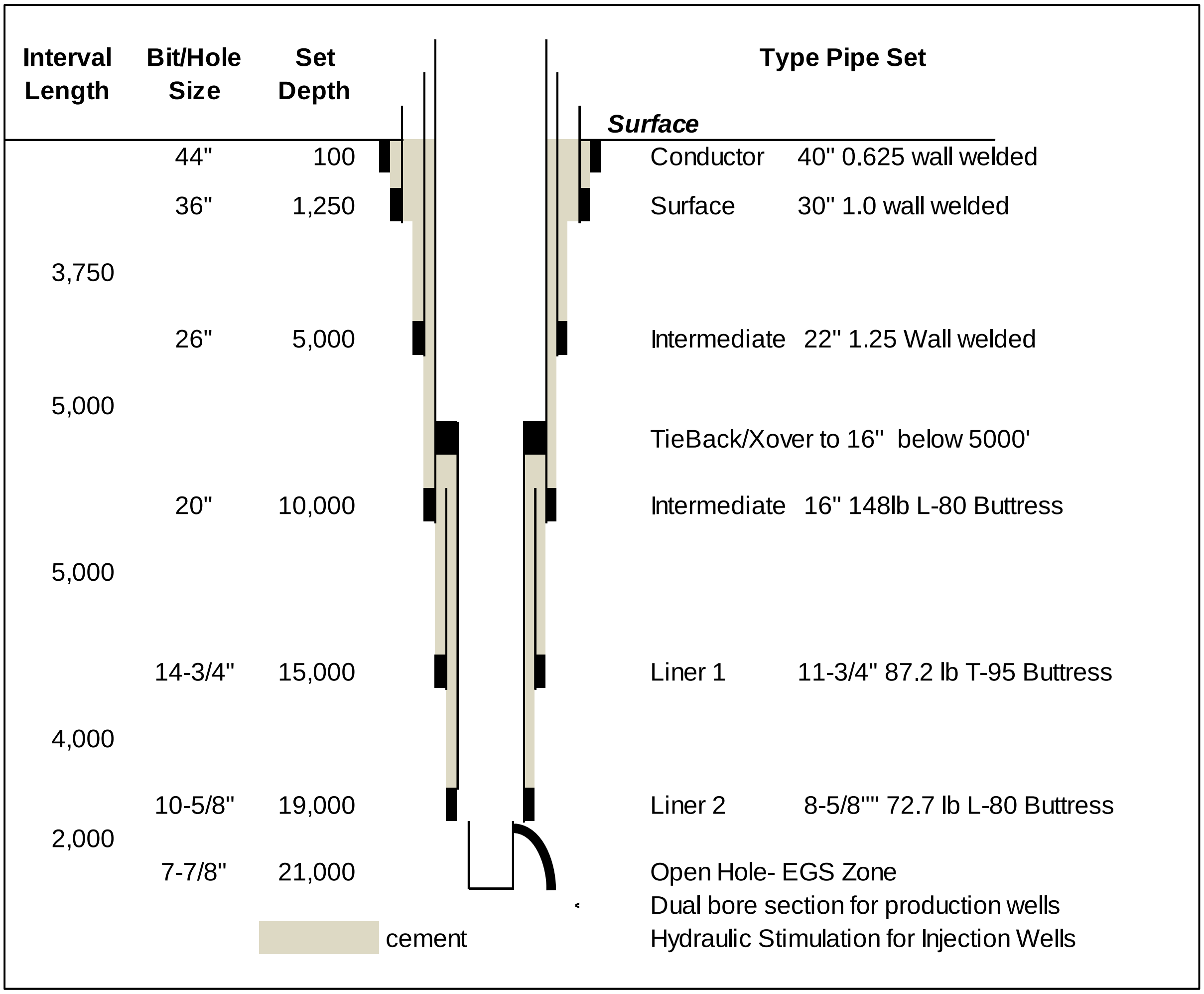


Figure 12: Small Diameter (8 Inch) Well Design for Water EGS Production Wells, SOPO 1

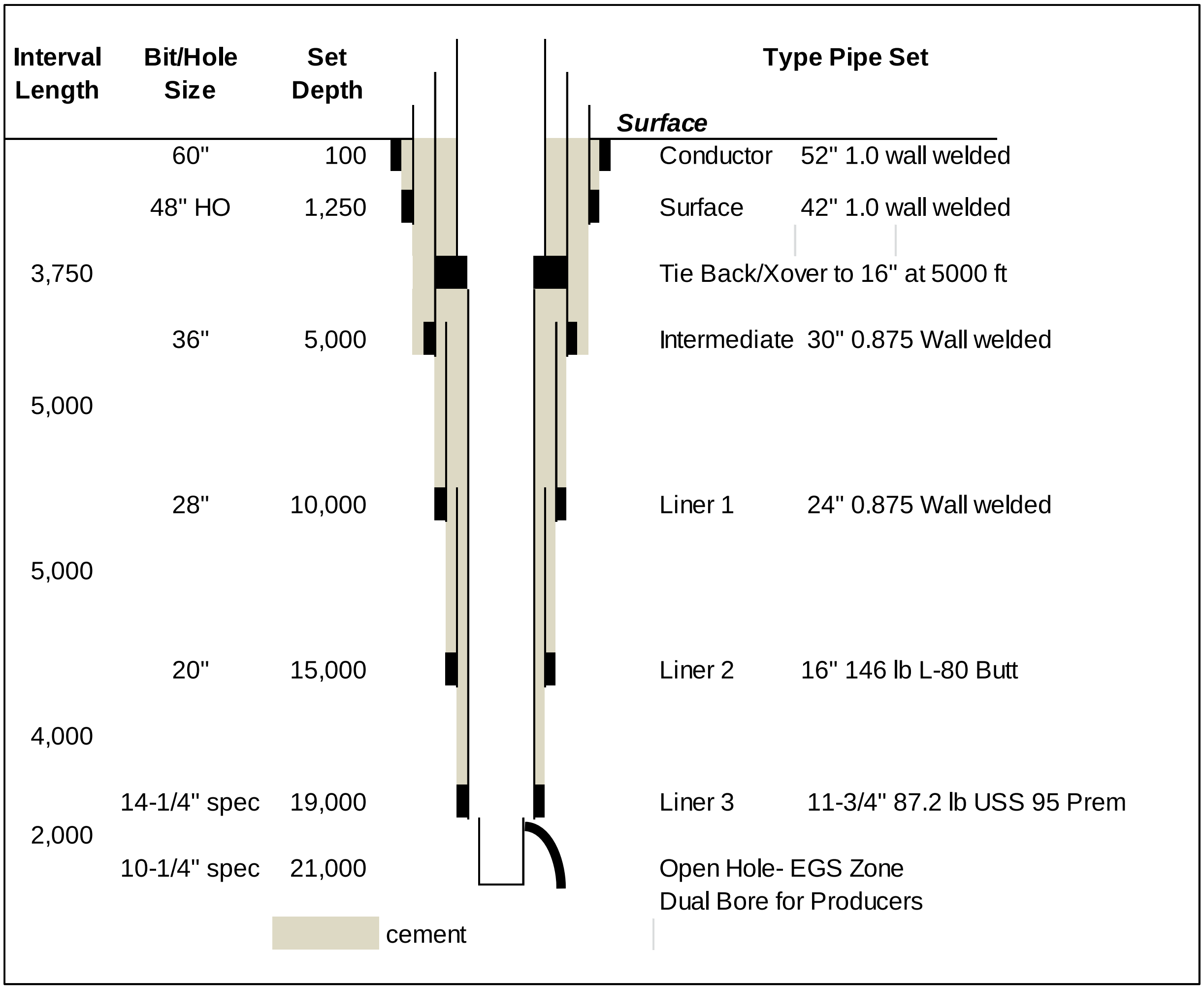


Figure 13: Large Diameter (10 in) Well Design for Water EGS Injection Wells, SOPO 1

As can be seen, the telescoping and tapered nature of the construction results in very large bit and casing size near the surface.

An analysis of the interval costs for the two well designs is detailed below. The design uses large diameter wells (10”) for injection wells (12 or 16 to handle the total flow at 50 or 70 MW gross) and small diameter wells (8”) for production wells (20 or 25 to handle the total flow at 50 or 70 MW gross).

Table 5: Interval Cost Estimate for 10 Inch Wells, 20,000 Feet, SOPO 1

20,000 feet ending in 10+" open hole								
Interval Costs								
	Interval 1	**Interval 2**	**Interval 3**	**Interval 4**	**Interval 5**	**Interval 6**	**Total**	**%**
Casing Set Point	1,250	5,000	10,000	15,000	19,000	21,000		
Interval length, ft	1,250	3,750	5,000	5,000	4,000	2,000	21,000	
Length of casing run, ft	1,250	5,000	5,200	5,200	19,000	-		
Activity								
Drilling time (cost in $)	$180,064	$307,133	$473,347	$627,516	$555,897	$301,111	$2,445,069	10.0%
Tripping time (cost in $)	$13,776	$25,745	$86,720	$145,437	$155,785	$265,580	$693,042	2.8%
Bits and tools	$149,500	$219,000	$407,000	$466,875	$617,760	$266,490	$2,126,625	8.7%
Directional Drilling	$3,960	$67,500	$198,767	$213,333	$193,846	$105,000	$782,406	3.2%
Casing (including time to run)	$976,550	$3,371,833	$2,431,593	$972,680	$1,706,420	$0	$9,459,077	38.7%
Cement (including time)	$928,540	$1,388,700	$974,010	$712,672	$1,691,431	$0	$5,695,353	23.3%
Drilling fluids (incl. air and cleaning equipment)	$26,333	$42,000	$115,500	$132,333	$93,846	$46,667	$456,679	1.9%
Trouble	$58,520	$194,830	$59,360	$32,680	$31,680	$63,360	$440,430	1.8%
End of interval (logging, testing, and wellhead)	$124,140	$298,103	$311,105	$601,576	$497,355	$521,487	$2,353,765	9.6%
Total interval costs	**$2,461,384**	**$5,914,845**	**$5,057,402**	**$3,905,101**	**$5,544,020**	**$1,569,694**	**$24,452,446**	100.0%
UpFront / Distributed Costs								
Rig mob and demob							$665,000	
Pre-spud engineering							$240,000	
Site prep, cellar, conductor							$154,500	
Contingency (10% of intangible drilling costs)							$1,499,337	
Total well cost							**$27,011,283**	
Analysis of Interval Costs								
Drilling Costs	$373,634	$661,378	$1,281,333	$1,585,494	$1,617,134	$984,848	$6,503,821	26.6%
Drilling $/ft of interval	$299	$176	$256	$317	$404	$492	$310	
Casing & Cement Costs	$1,905,090	$4,760,533	$3,405,603	$1,685,352	$3,397,851	$0	$15,154,430	62.0%
Casing $/ft of casing set	$1,524	$952	$655	$324	$236		$488	
Other Costs (not UpFront& Distrib)	$124,140	$298,103	$311,105	$601,576	$497,355	$521,487	$2,353,765	9.6%
Other Costs/foot	$99	$79	$62	$120	$124	$261	$112	
Total Cost per foot of Interval	$1,969	$1,577	$1,011	$781	$1,386	$785	$1,164	100.0%

Table 6: Interval Cost Estimate for 8 Inch Wells, 20,000 Feet, SOPO 1

20,000 feet ending in 7-7/8" open hole								
Interval Costs								
	Interval 1	**Interval 2**	**Interval 3**	**Interval 4**	**Interval 5**	**Interval 6**	**Total**	**%**
Casing Set Point	1,250	5,000	10,000	15,000	19,000	21,000		
Interval length, ft	1,250	3,750	5,000	5,000	4,000	2,000	21,000	
Length of casing run, ft	1,250	5,000	5,000	5,000	19,000	-		
Activity								
Drilling time (cost in $)	$180,064	$307,133	$473,347	$627,516	$555,897	$301,111	$2,445,069	13.5%
Tripping time (cost in $)	$13,776	$25,745	$86,720	$145,437	$155,785	$265,580	$693,042	3.8%
Bits and tools	$149,500	$221,000	$377,300	$340,313	$355,320	$209,790	$1,653,223	9.1%
Directional Drilling	$3,960	$69,000	$198,767	$215,000	$193,846	$105,000	$785,573	4.3%
Casing (including time to run)	$681,550	$2,046,833	$866,220	$762,245	$1,484,260	$0	$5,841,109	32.3%
Cement (including time)	$550,759	$870,600	$691,000	$427,480	$913,265	$0	$3,453,104	19.1%
Drilling fluids (incl. air and cleaning equipment)	$26,333	$42,000	$109,250	$115,667	$86,154	$46,667	$426,071	2.4%
Trouble	$58,520	$194,830	$59,360	$32,680	$31,680	$63,360	$440,430	2.4%
End of interval (logging, testing, and wellhead)	$123,140	$289,228	$304,699	$577,687	$490,509	$575,468	$2,360,730	13.0%
Total interval costs	**$1,787,603**	**$4,066,370**	**$3,166,662**	**$3,244,023**	**$4,266,716**	**$1,566,976**	**$18,098,349**	100.0%
UpFront / Distributed Costs								
Rig mob and demob							$500,000	
Pre-spud engineering							$240,000	
Site prep, cellar, conductor							$115,000	
Contingency (10% of intangible drilling costs)							$1,225,724	
Total well cost							**$20,179,074**	
Analysis of Interval Costs								
Drilling Costs	$373,634	$664,878	$1,245,383	$1,443,931	$1,347,002	$928,148	$6,002,976	33.2%
Drilling $/ft of interval	$299	$177	$249	$289	$337	$464	$286	
Casing & Cement Costs	$1,232,309	$2,917,433	$1,557,220	$1,189,725	$2,397,525	$0	$9,294,213	51.4%
Casing $/ft of casing set	$986	$583	$311	$238	$169		$305	
Other Costs (not UpFront& Distrib)	$123,140	$289,228	$304,699	$577,687	$490,509	$575,468	$2,360,730	13.0%
Other Costs/foot	$99	$77	$61	$116	$123	$288	$112	
Total Cost per foot of Interval	$1,430	$1,084	$633	$649	$1,067	$783	$862	100.0%

The drilling costs are incorporated into the total reservoir development cost estimate for the WBS 2 category in subcategories WBS 2.3 and 2.4. As can be seen, the well cost is significant, and over 50% of the cost of the wells are for casing and cement. Therefore, a focus on the development of technologies that reduce casing and cement cost would be very beneficial. Currently, DOE investment is steered more towards faster drilling, which is also of value – but is not the biggest part of the problem on the very expensive wells in this analysis.

There is a significant learning curve associated with drilling costs that can be applied as follows. The well cost is calculated based on best engineering estimating practices, in the 10" example, this number is $27M. The second well is at 91% of the estimated cost, and the third and subsequent wells are at 82% of the estimated cost. In the spreadsheet, for convenience, the first three wells are costed at 91% of the modeled price, and the rest are costed at 82% of the price. This methodology provides the same result, so long as the number of wells is always greater than three. Many experts and reviewers, including reviewers at DOE Merit Review, have suggested that much more aggressive learning curves can be used. This might be true on less expensive wells, where labor/time is the dominant cost, but these wells are dominated by material cost, which will not come down at as fast a rate as pure learning labor.

WBS 3 - Pumping and Backup Power Generation

WBS 3 develops the cost estimate for reservoir operation, which requires significant pumping, and the ability to start the system. Fairbanks Morse Engine provided the Pumping and Backup Power Generation cost analysis.

For the Westover AFB location, the capital cost associated with WBS 3 is $11M for the 70 MW gross water EGS system which uses an electric pump. The pumping and backup power generator capital cost for the 50 MW gross system with diesel pumps is $38M. Summary versions of the spreadsheet for WBS 3 are presented below.

Table 7: Summary Costs for WBS 3 - Diesel Pumping System, SOPO 1

WBS	Cost	Item	
3.0	**$38,512,000**	**Pumping System (Diesel)**	
3.1		Oxygen Plant (not part of SOPO 1)	
3.2		Combustion System / CCD System (not part of SOPO 1)	
3.3	**$32,652,000**	Diesel Driven Water Pumps	
		Details:	
		Cost of 1 32/40 Dual Fuel Engine & Speed Increaser plus Auxiliaries & Controls	6,913,000
		Cost of 4 injection pumps, mechanical drive versions (ROM)	5,000,000
		Injection Well engines Power Level	6,160
		Speed Increaser Gear Efficiency	1
		Specific Fuel Consumption	6,040
		Fuel Price ($/mmBTU)	4
		Number of dual fuel engines	4
		Hours of operation per year	8,000
		Production Pumps are included in WBS2	
3.4	**$3,580,000**	Diesel Gensets to Drive Production Pumps	
		Details (for backup genset as well)	
		Cost of 1 OP Dual Fuel Engine & Generator plus Auxiliaries & Controls	1,790,000
		Production Well and Base load engines Power Level	1,506
		Specific Fuel Consumption	6,400
		Fuel Price ($/mmBTU)	4
		Number of dual fuel engines	2
		Hours of operation per year	8,000
3.5	**$1,790,000**	Diesel Genset for Backup Power	
		Backup Genset	1
3.6	**$400,000**	Filtration	
3.7	**$90,000**	Freeze Protection	
3.8			
3.9	**$7,435,621.09**	**Fuel Costs (Not Summed Above)**	
	$2,273,504	**Engines Maintenance Costs (Not Summed Above)**	

WBS 3 costs include the associated topside equipment for reservoir filling and operation, but not geothermal energy conversion. In the case of the water EGS this includes the diesels engines and water pumps, and in the case of the CO_2 EGS this would include the CO_2 filling and top off system. WBS 3 also includes backup generator(s) and other systems associated with startup (CO_2 thermal siphon starter motor).

As outlined above, cost estimates were produced for two versions of geothermal system: a 70 MW gross system and a 50 MW gross geothermal hybrid system. The 70 MW gross system has 20 MW of electric water pumps, and with a small diesel backup generator set sufficient to start the plant from cold (1.5 MW). The 50 MW gross system has 20 MW of diesel engine driven pumps, and with the backup power. In both cases, cost estimates were based on Fairbanks Morse Engines. Costs for medium speed dual fuel (natural gas / diesel) engines were used to yield the best value in terms of fuel price and also to minimize emissions.

Note that the number of backup generator sets is reduced from 2 to 1 with the diesel pump option since electrical power needed for startup from cold is reduced with this option.

A subset of the WBS 3 Scope Supply for the backup generator (1.5 MW) and water pump engines are provided as follows:

Enviro-Design® OP Dual Fuel Generator Set
QTY 1 Six (6) Cylinder Model 38ETDD8-1/8 Opposed Piston (OP), Turbocharged, Dual Fuel Engine Generator Set, rated at 1580 kWe @ 900 RPM complete with auxiliary support equipment, including the following for each engine:

Engine:
- Model 38ETDD8-1/8
- Bore & Stroke 8-1/8" x 10"
- No. of Cylinders 6
- Horsepower 2205 BHP
- Overload 10% per DEMA Standard
- Speed 900 rpm
- Fuel Natural Gas with No.2 diesel pilot oil
- Cycle 2-Stroke

Engine Mounted Accessories:
- Automatic Air By-pass
- Air Motor Starting
- Exhaust Driven Turbocharger(s)
- Combustion Air Aftercoolers
- Fuel Oil Pump, Engine Driven
- Fuel Oil Filter
- Lube Oil Pump, Engine Driven
- Jacket Water Pump, Engine Driven
- Intercooler Water Pump, Engine Driven
- Emergency Shutdown Device
- Governor Actuator (Woodward EGB-13P or Equivalent)
- Manual Barring Device
- Barring/Starting Ring-gear
- Starting Air Motor(s)
- Thermocouples, Wire, and Junction Box
- On-Engine Instrumentation as Required by Fairbanks Morse
- Companion Flanges – For non-ANSI Connections
- Crankcase Manometer
- Lube Oil Strainer – Full Flow Simplex Type

Generator:

Air-cooled, open drip proof, synchronous generator with brushless integral direct connected exciter and permanent magnet pilot alternator (PMA). Rotor/stator winding insulation is rated class F. Stator windings are equipped with temperature detectors and include anti-condensation heaters.
Rated Output: 1580 kWe, 1975 kVA
Duty: Continuous
Voltage: 12.47 KV
Phase: 3
Frequency: 60 Hz
Power Factor: 0.8
Bearing type: Oil Lubricated Sleeve

Engine Generator Base:

Fabricated structural steel frame with integrated lube oil service tank for mounting the engine, coupling, generator and flywheel cover. Fully factory assembled, tested, and ready for installation.

Supporting Equipment / Auxiliaries:

- Control and Monitoring Equipment
- Lubricating Oil System
- Cooling Water Systems
  - Jacket Water Cooling System
  - Aftercooler Water Cooling System
  - Injector Water Cooling System
  - Service Water System
- Fuel Systems
  - Fuel Oil System
  - Fuel Gas System
- Combustion Air System
- Exhaust Gas System
- Starting Air Equipment (working pressure 250 psig)

A similarly detailed scope of supply was included and costed for the large diesels to drive the water pumps. The unique aspects of which are as follows:

Sixteen (16) Cylinder Model FM-MAN 32/40 DF Turbocharged, Dual Fuel Engine rated 6160 kWb (8260 bhp) at 720 rpm complete with base frame, gearbox, and supporting auxiliary equipment, including the following for each engine:

Engine

Type V 32/40 DF
Bore & Stroke 320 mm x 400 mm
Horsepower 8260 BHP
Speed 720 RPM
Fuel Natural gas with 1% diesel pilot
Cycle 4-stroke

Gear Box

Gearbox, with single input and single output, to be mounted on the steel base frame and direct connected to the engine flywheel via a torsional flexible coupling. Output flange of to connect to the high pressure water injection pump (supplied by others).

WBS 4 - Energy Conversion and Power Distribution Equipment

WBS 4 is a cost estimate for the energy conversion part of the geothermal system (geothermal power generation) equipment. Turbine Air Systems (TAS) performed the power conversion equipment design and costing required by WBS 4 for the baseline 50 and 70 MW gross systems at Westover AFB (water EGS systems), and also for the CO_2 systems to be discussed later in this report. The total WBS 4 costs for the 50 MW Gross and 70 MW Gross systems are $151M and $187M, respectively.

Table 8: Summary Costs for WBS 4 - Power Generation, SOPO 1

WBS	50 MW Gross		70 MW Gross
4.0	**$151,000,000**	**Power Generation - Organic Rankine Cycle (ORC)**	**$187,400,000**
4.1	**$29,000,000**	Rotating Equipment (Turb / Gen / Pump)	**$40,600,000**
4.2	**$39,000,000**	Heat Exchangers	**$54,600,000**
4.3	**$11,000,000**	Electrical	**$15,400,000**
4.4	**$12,000,000**	Packaging / BOP	**$16,800,000**
4.5	**$6,000,000**	Consumables	**$6,000,000**
4.6	**$4,000,000**	NRE	**$4,000,000**
4.7	**$25,500,000**	ORC Installation	**$25,500,000**
4.8	**$18,500,000**	On Site Integration	**$18,500,000**
4.9	**$6,000,000**	Testing	**$6,000,000**

The energy conversion system includes turbines, condensers, feed pumps, and associated topside equipment, including cooling towers if needed (air cooled is an option in some of the locations considered). Most of the effort in this section is spent on the analysis and options related to WBS 4, especially for CO_2, since the WBS 4 equipment is quite different from a conventional ORC.

A conventional ORC is used for the water EGS cost estimate. R134A refrigerant is used in a single stage turbine with recuperator. The details of the TAS design are proprietary to TAS, but rudimentary calculations show how 7% efficiency is possible with this type of ORC, given the heat source (297 deg F topside temperature) and hotwell (125 deg F) temperatures.

Table 9: Organic Rankine Cycle Operating Conditions, SOPO 1

Assumptions:						
High Side Pressure		Exhaust Pressure		Hot Side deg F		
650.00	PSIA	225.00	PSIA	297.00		
		HX Delta T			R134A Saturation Pressure vs.	
Nstage	1	10.00			Temperature to the Critical Point	
Hot Well Temperature		125.00			Temperature	P Sat
Recuperator Eff	60.0%				deg F	psia
Turbine Eff	80.0%	(isentropic)			80	101.4
					100	138.9
Results:					120	185.9
Massflow	(ORC working fluid)		8261.7	LBM/SEC	140	243.9
Power (Net)			50	MW (e)	160	314.7
Gen Efficiency	97.0%		69097	hp shaft net	180	400.3
N Cycle			7.23%		200	503.6
Pump Power			20.25	(MW or MW(e))	213.9	588.7

The above table is not optimized, but serves to provide an indication of the conditions inside the ORC. The ORC system costing is provided in the table below. A detailed discussion of the system design follows.

Surface Facilities Layout

The design considered is based upon TAS binary modular rapidly deployable power plant systems, with the potential for multiple units to be centrally located, or distributed appropriately according to the drilled well distribution and configuration. It is inherently more efficient to located the power plant at the well pad and distribute medium voltage power to the substation, than it is to centrally locate the power plants together, and distributed the pump production power and insulated brine supply and reinjection return piping.

Assumptions are:

- A resource temperature of 300°F and pumped production and reinjection wells - which are best suited for a binary power plant with 100% produced water injected back to the reservoir.
- Eight (8) modules of about 8.8 MW (70/8) or 6.3 MW (50/8) capacity each would deliver 50 MW (net) power after pumping.

A system conceptual layout for each power module is provided below. This layout leverages existing (fielded) power systems produced by Turbine Air Systems.

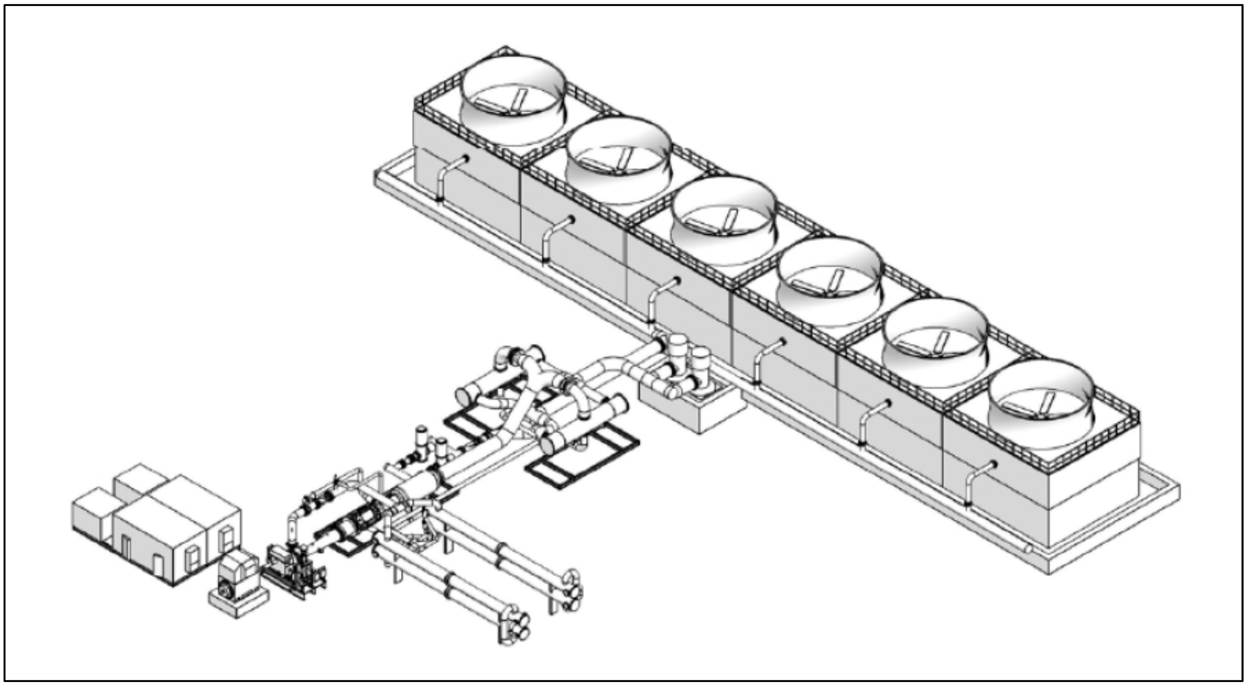


Figure 14: Conceptual Layout of Organic Rankine Cycle Power Module

WBS 5 – Interconnection with On Site Loads

WBS 5 is for the connection of power from the plant to local needs. GEECO provided the interconnection cost estimate. A fixed cost of $3.5M for WBS 5 was used for all locations.

It was assumed that the cost of local interconnection would be nearly insignificant compared to the scope of the other WBS categories. More importantly those costs do not change appreciably as the geothermal designs vary. The $3.5M cost assumes $1M for integration of available waste heat for local use, and $2.5M for electrical connection to serve onsite loads.

In the overall cost analysis, the portion of the loads that offset retail electricity costs (vs. the portion that is sold at wholesale) is an important variable in revenue generation. For the purposes of the study it is assumed that interconnection facilities to local (onsite) loads are sufficient to handle the full output of the 50 MW net system.

WBS 6 - Grid Interconnection

WBS 6 is for accounting for grid interconnection costs for the Project. GEECO developed the cost estimate for grid interconnection. A fixed cost of $18M for WBS 6 was used, for every location.

This cost assumed $1.5M each for control monitoring system and transfer switch gear, and $15M for power integration equipment required to make the connection to the grid at the required location. This cost could vary widely depending on the location of the grid interconnection point in relation to the location of the power plant; however, it was not the purpose of this study to address grid connection technologies or costs. For the purposes of the study it was assumed that no significant upgrades to the grid would be required to handle the full output of the 50 MW net system.

WBS 7-10 - Project Management, Permitting, Operation

WBS 7-10 provides estimates of costs for the categories listed below. These cost estimates were developed by CLF Ventures and Fort Point Associates.

- WBS 7: Top of well sites and facilities to house surface elements;
- WBS 8: Land acquisition and / or land use w/ royalty agreements;
- WBS 9: Federal, State local and private (stakeholders) permits, approvals, incentives; and
- WBS 10: Project management.

WBS 7 – Top of Well Sites and Facilities

WBS 7 is an estimate of construction costs of the top of well site and facilities to house surface systems. The WBS 7 costs for the 70 MW gross and 50 MW gross water EGS systems at Westover AFB are estimated to be $8.3M and 6.7M respectively. These costs are detailed in the table below:

Table 10: Summary Costs for WBS 7 - Top of Well Site and Facilities, SOPO 1

WBS	70 MW Gross		50 MW Gross
7.0	$8,330,000	**Top of well sites and facilities to house surface elements**	$6,730,000
7.1		**Design**	
7.1.1	$500,000	Engineering: Survey of property, soil borings, design of topography, stormwater management, standard building utility connections	$400,000
		Cost is largely dependent on size and number of structures and terrain to be constructed on	
7.1.2	$30,000	Design of Concrete pads for external pump/power equipment	$30,000
		Cost will vary depending on number of external equipment pieces and repetitive design	
7.2		**Construction**	
7.2.1	$5,000,000	Major Buildings	$4,000,000
		This estimate provides for a building of approxiamtely 40,000 square feet along with essential aspects of insulation, HVAC, electrical, plumbing, control room, office space, bathrooms, and security.	
		The weight of building will be substantial with interior components. The foundation cost is largely variable based on soil stability present on the site and weight of the mechanical components chosen for the project.	
7.2.2	$500,000	Construction of Concrete Pads / Foundations for External Pump / Power Equipment	$500,000
		Estimate that will change based on the size and number of pads/foundations. Does not include pile driving for weak soil stability.	
7.2.3	$800,000	External Equipment Shelters	$600,000
		Due to the design of a network of wells, the potential for up to 20 equipment shelters of ranging sizes may be necessary during winter conditions dependant on the efficiency of the layout of the well heads, piping network and pump components. Any shelter with mechanical fluids may need to insulated and heated. Does not include electrical connections cables, connects or fixtures	
7.2.4	$1,500,000	Earthwork for stormwater, utilities and conduit trenches between main building and well heads; exclusive of building and foundation construction	$1,200,000

WBS 7 Notes:

1. The above estimates are based upon team experience in the industry with limited communication with agencies, landowners, community groups.
2. Water wells for source water and reinjection to groundwater are included within the drilling costs for reservoir development detailed in WBS 2.
3. There are power transmission lines just north of the west bound travel lanes of the Massachusetts Turnpike, approximately 3 miles to the South of a potential location to build a 50 MW facility on the Westover Air force Base. There is a transmission line running along Perimeter Road/Patriot Ave at the northeast edge of the Westover Air force Base. This line runs near the western edge of the base south toward the mass Pike and the transmission station stated below. Another larger transmission line runs generally north-south just west of Route 33 in Chicopee, MA. A power transfer station is

located just north of the Mass Pike, East of Route 291, off of Shawinigan Drive in Chicopee, MA. A power transfer station is located just north of Route 21 and East of Lyon Street, in Chicopee, MA.

4. The locations of the transmission lines and substations are based on analysis of aerial maps, Google Earth and Google Maps.

WBS 8 – Land Acquisition and/or Land Use with Royalty Agreements

The WBS 8 cost for land acquisition and / or land use with royalty agreements for the 70 MW gross system is estimated to be $15.4M. The cost for the 50 MW gross system is estimated to be $12.0M. A summary of the costs estimates is provided in the table below:

Table 11: Summary Costs for WBS 8 - Land Acquisition, SOPO 1

WBS			
	70 MW Gross		*50 MW Gross*
8.0	**$15,400,000**	**Land acquisition and / or land use w/ royalty agreements**	**$12,011,035**
8.1		**Primary Site Acquisition**	
8.1.1	**$100,000**	Consulting Costs for property locating and feasibility studies	**$100,000**
8.1.2	**$15,000,000**	Vary by size of facility (acres) and value of land; Assume average cost	**$11,677,486**
		@ $10,000 per acre for 2,500 acres = **$25,000,000**	
		@ $5,000 per acre for 150 acres = **$1,250,000**	
8.1.3	**$300,000**	Closing Costs (2%) for land purchase	**$233,550**

The costs of the 50 MW gross system developed by scaling the 70 MW system cost analysis, resulting in a total cost of $12,011,035. While these costs are based on land purchase for ease of calculation, in practice, a land lease or land use agreement with royalty might be negotiated. This type of agreement between the land owner and the project developer is put in place for the development and operating periods of the project and the payment to the lessor is based on the project output and project revenue.

WBS 8 Notes:

1. The above estimates are based upon team experience in the industry with limited communication with agencies, landowners, community groups.
2. This cost estimate assumes acquisition (by lease or purchase) of a single large parcel of land on an existing military base. For the benefit of simplifying assumptions, a single large land owner is assumed. If a smaller area of land is purchased or leased, a larger number of adjacent properties may be necessary to provide the required subsurface property rights. The assumption of a single large land owner reduces the price ambiguity for subsurface property rights costs.

3. It was assumed that the base will have access to existing transmission access, so there will be no addition cost to acquire new access. This is true for all cases (all locations and for both H_2O and CO_2 systems.)
4. The cost of the land was estimated using information obtained from the Zillow.com website. The costs for the largest tracts of land near the specified location, but not in an urban environment, were used as the most reasonable approximation of land costs.

WBS 9 - Federal, State, Local and Private (stakeholders) Permits, Approvals, and Incentives

The total cost for WBS 9 of $3.7M is used for both the 50 MW gross and 70 MW gross water EGS cases at Westover AFB. The table below provides detail for WBS 9 costs:

Table 12: Summary Costs for WBS 9 - Federal, State and Local Permitting

WBS	*70 MW Gross*	
9.0	$3,730,000	**Federal, State local and private (stakeholders) permits, approvals incentives leading to and enabling construction and operation of H2O EGS applications**
9.1		**Consulting efforts toward receiving Permit and Approvals**
9.1.1	**$600,000**	Research and Planning of approval process, coordination with project team, permit expediting
9.1.2	**$250,000**	Stakeholder and Regulatory: Assessment, design of strategy, informational meetings, media and communications plan
9.1.3	**$100,000**	Contingency for Education/Outreach with local and state officials (including fees for agency expert consultation)
9.2		**Permit and License Fees**
9.2.1	**$50,000**	Building Permit Fee (Estimate based on City of Chicopee fee of $0.60/SF plus specific fees)
		Maximum Building Permit Fee is based on a cost of $7 per $1,000 of building code specific construction cost of surface building construction only.
		Minimum Building Permit Fee is based on the City of Chicopee building permit cost structure ($0.50/sf general permit cost, $0.10/sf electrical fee, plus other fees)
9.2.2	**$30,000**	Other Permit Fees (Rough Estimate)
9.2.3	**$500,000**	Interconnection with Electric Grid (Fees and Two Studies)
		(natural gas and geothermal)
9.3	**$600,000**	**Mitigation Requirements**
		To be further determined when interaction is appropriate with reviewing agencies, community groups and abutters
9.4	**$1,600,000**	**Contingency for appeals and other stakeholder intervention**

WBS 9 costs, especially those associated with permitting and the required analysis associated with permitting, vary from one region to the next due to a number of factors. Not only do regulatory requirements differ for each location, but also, the individual preferences of local stakeholders and authorities having jurisdiction come into play as well, requiring adaptation on the part of the developer. Moreover, costs do not scale with project size within the range contemplated by this study.

WBS 9 Notes:

1. The above estimates are based upon team experience in the industry with limited communication with agencies, landowners, community groups.
2. Known Permits or permitting agencies consist of: NEPA, MEPA, City Planning, City Zoning, DEP Notice of Construction, DEP Dewatering, DEP Groundwater Discharge; Underwater Injection Control for Each Well; Air Quality Review; Electric Utility Interconnection Agreement; Natural Gas Utility Agreement; EPA NPDES Construction; EPA NPDES Industrial Discharge Permit; City Building Permit; Local Board of Health; MA State Permit for water withdrawal- threshold.
3. Other Potential Permits or authorities having jurisdiction (AHJs) may include: Army Corps of Engineers, Local Water and Sewer Authority, MA Historical Commission Finding of No Adverse Effect, LPA Air Quality Approval; State Fire Marshal Hazardous Materials Storage; Local Conservation Commission; FEMA Flood Map Revision; DEP Water Quality Certificate; Mass DOT; Municipal Public Works.

WBS 10 – Project Management

WBS 10 is the cost of the lead developer's oversight level of project management for the construction phase of the project alone. WBS 10 Project management costs are provided in the table below for the 70 MW gross water EGS case, and total $18.2M. The 50 MW gross water EGS system is costed similarly, but is a 9 year construction project, not 10 years, and has a total cost of $15.7M.

Table 13: Summary Costs for WBS 10 - Project Management, SOPO 1

WBS	***Costs in 1000s***		PROJECT MANAGEMENT										
70 MW Gross													
10.0	**$**	**18,250**	***Year***	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
10.1	**$**	**400**	**PLANNING & SCHEDULING**	40	40	40	40	40	40	40	40	40	40
10.2	**$**	**140**	**DOCUMENT CONTROL & DESIGN**	40	20	10	10	10	10	10	10	10	10
10.3	**$**	**160**	**QUALITY ASSURANCE**	-	-	20	20	20	20	20	20	20	20
10.4	**$**	**6,450**	**PROCUREMENT & FIELD CONTRACT**	300	300	600	750	750	750	750	750	750	750
10.5	**$**	**3,900**	**CONSTRUCTION MANAGEMENT**	-	300	450	450	450	450	450	450	450	450
10.6	**$**	**120**	**MANAGEMENT INFORMATION SYS**	30	10	10	10	10	10	10	10	10	10
10.7	**$**	**80**	**INSPECTION & TESTING**	-	-	10	10	10	10	10	10	10	10
10.8	**$**	**7,000**	**INSURANCE, WORKPLACE SAFETY**	-	-	875	875	875	875	875	875	875	875
			Total:	410	670	2,015	2,165	2,165	2,165	2,165	2,165	2,165	2,165

WBS 10 covers the costs of overall project management and coordination by the project development entity. Project management costs for the other project components such as exploration, reservoir development, drilling, pumping and backup power, power generation, etc., are accounted for within their respective WBS items, in particular WBS 2 through 7. The cost of the management of the project during the operating phase is accounted for in the summary sheet as part of the Operations and Maintenance line item.

WBS 10 Notes:

1. WBS 10 captures project development and management costs that are not included in WBS 1-9.
2. A developer and an Engineering Procurement Construction (EPC) contractor are responsible for developing and constructing the project.
3. Included are direct costs for salary and wages and indirect costs consisting of rent, light, taxes, benefits, material etc. The indirect costs consist of one-third of the total costs listed for each item.
4. An average salary of $100,000 a year was assumed.
5. Commissioning and testing are included in capital costs elsewhere in the model.
6. Insurance costs are assumed to be 1% of the total construction costs annually.
7. Reservoir development is estimated to take 8 years for the 70 MW reservoir and 6.67 years for a 50 MW reservoir.

50 MW Water EGS Cost Baseline Summary Results

The capital cost for all the items associated with the construction of the 50 MW EGS system are rolled up into a higher level spreadsheet, and the levelized cost of electricity is calculated. Using the levelized electricity rate, the profit or loss of the proposed venture is calculated.

The capital costs for the 50 MW gross and 70 MW gross versions of the geothermal system are summarized in the Table below.

Table 14: Cost Summary for WBS 1 - 10, SOPO 1

WBS	Capital Cost		WBS Element
	70 MW Gross	50 MW Gross (GT)	
	50 MW Net	20 MW Hybrid Pump	
	Electric Drive	Diesel Drive	
1.0	$3,710,000	$3,710,000	Resource ID / Analysis
2.0	$890,540,446	$699,109,235	Reservoir Development
3.0	$11,070,000	$38,512,000	Fluid Management (topside)
4.0	$187,400,000	$151,000,000	Power generation
5.0	$3,500,000	$3,500,000	Integration / Distribution (local)
6.0	$18,000,000	$18,000,000	Integration / Distribution (grid)
7.0	$8,330,000	$6,730,000	Topside Structures
8.0	$15,400,000	$12,011,035	Land Acquisition / Land Use
9.0	$3,730,000	$3,730,000	Permits / Approvals
10.0	$18,250,000	$15,724,167	Project Management
Total	$1,159,930,446	$952,026,437	

As can be seen, the capital cost for the Project is significant. The dominant cost is the reservoir development, and as can be seen from the WBS 2 spreadsheet, the greatest portion of the reservoir development cost is drilling. In fact, the total drilling and hydraulic fracturing costs are $854,340,446 for the 70 MW gross system, which is over 73% of the total project cost. In the 50 MW gross water EGS system, with 20 MW of diesel pumping, the amount and portion of drilling cost is lower, since a smaller reservoir is needed, and since the capital cost of the diesel driven pumping system (used in the 50 MW gross case) is higher than electric drive pumps (used in 70 MW gross system). Still, the cost of $666,809,235 for drilling and fracturing for the 50 MW gross water EGS case is still the dominant cost, at around 70% of total project cost.

Although interest rates are at record lows at the time of this writing, the cost of money, for a 10 year construction effort, for a power project, and of a type not previously demonstrated will be high. The assumptions on cost of money will radically change the results on levelized cost of electricity and project profit / loss. In order to have an apples to apples comparison within this document, we will assume 7% interest and 20 year amortization. In reality, different phases of the Project will require different types of finance, and early exploration / drilling will be at much higher interest rate and shorter term than later phases of construction – but the assumption used appears to be a reasonable average.

The SOP0 1 summary spreadsheet for the 70 MW gross water EGS system with electric drive pumps is provided below:

Table 15: Summary Spreadsheet for 70 MW Gross Water EGS, SOPO 1

Parameters:	Water EGS		Comment	
Gross Power	70	MW	Geothermal Gross Power, Not Plant	
Net Power	50	MW		
Water Pump Power	20	MW	(from WBS 3)	
Cost of Electricity (retail)	$167	$/MW-hr	(US DOE EIS 2008 MA)	
Cost of Electricity (wholesale)	$81	$/MW-hr	(ISO NE 2008 Hub Price)	
MA Renewable Market Class 1 RPS	$13	$/MW-hr		
Capital Cost	$1,159,930,446	(roll up)	(from capital sheet)	
Cost of Capital	7.0%	(high)	(variable)	
	20	(30 year default)		
Annual Capital Cost	$109,489,228		(calculation)	
O&M Cost	$10	$/MW-hr	2007 GRC Presentation	
Availability	99.5%	(uptime)	(guess)	
<u>Cost Item</u>	<u>$</u>			
Annual Capital Cost	$109,489,228		Escalation Rate (%/year)	
O&M Cost	$4,358,100		2.0%	
O&M Cost Engines	$240,960			
Purchased Costs (Fuel / Electricity)	$827,206		1.811361584	(30 year)
Total Annual Cost	$114,915,495			
	<u>Revenue (1st Year)</u>		<u>Revenue (30th Year)</u>	
		Percent	Impact of Escalation in Electric Costs	
Offset of Retail Electricity	$36,390,135	50.0%	$65,915,693	
Wholesale Electricity	$17,650,305	50.0%	$31,971,084	
MA Renewable Market Class 1 RPS	$5,665,530		$5,665,530	
Renewable Investment Tax Credit	$8,716,200		(Zero After 10 Years)	
Total Revenue	$68,422,170		$103,552,307	
Profit / Loss	($46,493,325)		($11,363,188)	

As can be seen, this project would lose substantial sums of money. The calculation of project cash flow is made in the following manner:

1. Capital Cost is amortized based on the variables in the summary to generate the amortized capital cost.
2. O&M cost is a fixed rate against produced power, and based upon various recent GEA presentations, the rate of 1 cent per kW-hr, $10 / MW-hr is used.
3. O&M cost of the engines, in this case the backup generator and in other cases the hybrid power/pumping/filling systems is based on vendor experience.
4. Items 1-3 are added with the purchased cost of fuel to generate a total annual cost.

5. Revenue is calculated based on the split of power sold locally (to offset retail costs) and sold as wholesale to the grid. The ratio of 50/50 is used throughout this document. Since this was a 2009 ARRA proposal contract, at the time the effort began, the 2008 rates for MA and ISO NE were used.
6. The local renewable credit, again for Massachusetts, and investment tax credit are also added to the revenue line.

The project loses $46M in the first year of operation with this calculation methodology and assumptions. Assuming electric price escalates, and other costs remain essentially fixed, it would get closer to profitable towards the end of life (30 years), but is still estimated to lose over $10M.

For this location, and this technology, the revenue line is approximately 60% of costs for the assumptions given. The break-even point would occur with much higher electricity price, and/or lower cost of money. For example, a reduction in interest rate to 3% (with a 20 year term) and a change of the assumption on retail / wholesale split to 100% retail would just break even in year one. Perhaps a college, with access to a large endowment and a desire to go off the grid could take on the project, but it remains risky at best.

The switch to diesel driven water pumps improves the project cashflow, but not to the point of profitability for this set of assumptions. The SOPO 1 summary spreadsheet for the 50 MW gross hybrid geothermal system with diesel driven pumps is provided below:

Table 16: Summary Spreadsheet for 50 MW Gross Water EGS, SOPO 1

Parameters:	Water EGS		Comment	
Gross Power	50	MW	Geothermal Gross Power, Not Plant Total	
Net Power	50	MW		
Water Pump Power	20	MW	(from WBS 3)	
Cost of Electricity (retail)	$167	$/MW-hr	(US DOE EIS 2008 MA)	
Cost of Electricity (wholesale)	$81	$/MW-hr	(ISO NE 2008 Hub Price)	
MA Renewable Market Class 1 RPS	$13	$/MW-hr		
Capital Cost	$952,026,437	(roll up)	(from capital sheet)	
Cost of Capital	7.0%	(high)	(variable)	
	20	(30 year default)		
Annual Capital Cost	$89,864,561		(calculation)	
O&M Cost	$10	$/MW-hr	2007 GRC Presentation	
Availability	99.5%	(uptime)	(guess)	
<u>Cost Item</u>	<u>$</u>			
Annual Capital Cost	$89,864,561		Escalation Rate (%/year)	
O&M Cost	$4,358,100		2.0%	
O&M Cost Engines	$2,273,504			
Purchased Costs (Fuel / Electricity)	$7,435,621		1.811361584	(30 year)
Total Annual Cost	$103,931,786			
	<u>Revenue (1st Year)</u>		<u>Revenue (30th Year)</u>	
		Percent	Impact of Escalation in Electric Costs	
Offset of Retail Electricity	$36,390,135	50.0%	$65,915,693	
Wholesale Electricity	$17,650,305	50.0%	$31,971,084	
MA Renewable Market Class 1 RPS	$5,665,530		$5,665,530	
Renewable Investment Tax Credit	$8,716,200		(Zero After 10 Years)	
Total Revenue	$68,422,170		$103,552,307	
Profit / Loss	($35,509,616)		($379,479)	

This is a substantially better result, but not good enough. The break-even point would still require 100% retail sales, and better financing terms, though it can be made to work at 30 years with reasonable interest rate (6%), and would be quite profitable ($>9M in the first year) at the rates a college might be able to "self finance".

These cases, even though not financially viable with conventional finance, will serve in the balance of this document as a baseline for comparison. As discussed, and as per the SOPOs for this contract, we will now address:

1. SOPO 2 - The change from a Water EGS to a CO_2 EGS at this location (Westover AFB, MA).
2. SOPO 3 - The additional change associated with drilling technology and CO_2 generation technology at this location (Westover AFB)
3. SOPO 4 - Other locations.

SOPO 2 - Impact of CO_2 on Cost Baseline Results at Westover AFB Site

As discussed previously, CO_2 as a working fluid in an EGS system, if properly implemented, has three major benefits:

1. First, it can eliminate pumping power, due to the fact that CO_2 will circulate with a positive pressure thermal siphon.
2. Secondly, the use of CO_2 further reduces machinery cost and increases cycle efficiencies if the CO_2 gas is expanded directly in a turbo-expander that is used to drive an electric generator. This is in contrast to the approach used in water EGS systems of transferring heat to an organic rankine cycle (ORC) working fluid (refrigerant) via heat exchangers, in order to generate power.
3. Last, and most importantly, the higher cycle efficiency of the direct CO_2 turbine approach yields substantially smaller EGS reservoirs for a given net electrical power output.

Pure dry CO_2 is an ideal working fluid because it is non-corrosive, and has strong thermal siphon properties. CO_2 is also an ideal heat transfer medium for the reservoir because it provides an order of magnitude lower kinematic viscosity ratio, yielding better reservoir contact and lower pressure drop through the rock.

Though CO_2 has a lower specific heat than water by 50%, given a typical pressure drop through the rock and porosity, CO_2 flow rate will be about 4 times higher than water. The net result is that CO_2 can remove heat from the rock more effectively than water, especially at lower temperatures, where the differences in kinematic viscosity is greater between CO_2 and water. This general result would cause one to believe that CO_2 might be better in lower temperature reservoirs, and water in higher temperature reservoirs.

It is not that simple, since the other major factor is the level of thermal siphon produced, and more so than temperature at the surface what is the pressure / temperature and how suitable is that for direct expansion in a CO_2 turbine. In all cases studied herein, pure dry CO_2 on a pure cycle efficiency basis would be better than water.

Unfortunately, we do not have pure dry CO_2 in an EGS, and will only approach it fairly late in the development cycle of the Project, if there is no naturally occurring aquifer. In almost all cases, initially the reservoir will be filled with water, and as the CO_2 is introduced, it will begin to displace water and will become saturated in the water, yielding concentrated, hot carbonic acid. Carbonic acid is a corrosive agent at the temperatures and pressures of the geothermal reservoir. Overtime, the carbonic acid / water will be removed, and we will end up with CO_2, but still saturated in water – never fully dry, and still quite corrosive.

The team made an assessment and concluded that there was no currently available product, suitable for the temperatures, pressures, sizes of the Westover AFB geothermal design that would handle the CO_2 / water pipe corrosion issue in the production wells other than stainless steel. Given the SOPO 1 results, where liner / casing cost dominated the drilling and hence reservoir development costs, it was clear that the SOPO 2 thermal design needed to strive for the highest efficiency to reduce the size of the reservoir and associated number of very expensive wells with stainless steel casings.

The effect of drilling to deeper depths was assessed using the thermodynamic model. Wells to 30,000 ft were selected as a reasonable limit. The depth of 30,000 ft yielded much higher bottom hole temperatures, attendant higher topside temperatures, and a 50% stronger thermal siphon of 3700 psi versus 2400 psi. The combined effect was to greatly reduce well count. The 30,000 ft. depth also enabled a thermal siphon strong enough that the size of the production wells could be reduced from 10” bottom hole to 8”. Due mainly to a savings in the number of wells, this is one of the few cases in geothermal power where “deeper is cheaper”.

Table 17: Thermodynamic Model for 30,000 feet CO_2 EGS in Western Massachusetts, SOPO 2

Assumptions:					Results:				
Surface Temperature = 66 deg F (yearly average)					Massflow			2698	LBM/SEC
Temperature Gradient =		1.21	deg F / 100' (Subir Report)		Heat Rate Extracted from Earth=			799	MMBTU/hr
Isentropic Compression / Expansion on Way Down / Up				H Trb inlet	Power		DH Cooler	50	MW
1000 psia injection pressure (near optimum)				(BTU/lbm)			(BTU/lbm)	69097	hp shaft
50 MW Net				201.5	Earth System Cycle Efficiency		63.5	21.3%	
Turbine Efficiency =		80.0%	(isentropic)						
Down Hole (Injection Temperature) =			80	H Injection	H Ex Isen	H Ex	DH Turb	T Ex	T Sat Ex
			deg F	(BTU/lbm)	(BTU/lbm)	(BTU/lbm)	(BTU/lbm)	(deg F)	(deg F)
carbon dioxide		Unit system:	E	119.9	178.9	183.4	18.1	98	82
Pressures Shown due not include surface									
piping or well pipe pressure drop				H Bottom Inj	H Bottom Prod.	DH Bottom	S Turb	S Top Inj	S Bottom
Average Density (bottom, lbm/ft^3) =			51.8	(BTU/lbm)	(BTU/lbm)	(BTU/lbm)	BTU/lbm R	(BTU/lbmR)	BTU/lbm R
				158.2	240.5	82	0.4096	0.3011	0.4096
Increment =	1500	ft per calculation							
				Pressure Drop Inj to Production (@ Bottom) =			400	psi	
			Injection Wells				Production Wells		
Calc Step	Depth		Temp (Inj)	Density (down)	Injection Well	Temp @ Depth	Temp Up	Pressure	Density
	(feet)	(m)	F	(lbm/ft^3)	(psia)	F	F	(psia)	(lbm/ft^3)
0	0	0	80.0	43.9	1000	66	269	3691	29.6
1	1500	457	92.1	45.9	1457	84	280	4010	30.6
2	3000	914	102.3	47.4	1935	102	291	4340	31.7
3	4500	1372	111.3	48.6	2428	120	301	4680	32.7
4	6000	1829	119.5	49.6	2934	139	311	5030	33.6
5	7500	2286	127.0	50.6	3451	157	321	5389	34.5
6	9000	2743	134.0	51.4	3978	175	330	5757	35.3
7	10500	3200	140.7	52.2	4514	193	338	6134	36.1
8	12000	3658	146.9	52.9	5058	211	347	6518	36.9
9	13500	4115	152.9	53.6	5609	229	355	6911	37.7
10	15000	4572	158.6	54.3	6168	248	363	7311	38.4
11	16500	5029	164.1	54.9	6733	266	370	7718	39.1
12	18000	5486	169.4	55.4	7304	284	377	8132	39.8
13	19500	5944	174.5	56.0	7882	302	385	8553	40.4
14	21000	6401	179.5	56.5	8465	320	391	8980	41.0
15	22500	6858	184.2	57.0	9053	338	398	9414	41.6
16	24000	7315	188.9	57.5	9647	356	405	9853	42.2
17	25500	7772	193.4	57.9	10245	375	411	10299	42.8
18	27000	8230	197.8	58.4	10848	393	417	10750	43.3
19	28500	8687	202.1	58.8	11456	411	423	11207	43.8
20	30000	9144	206.3	59.2	12069	429	429	11669	44.4

The above thermodynamic model shows the 30,000 ft case at Westover AFB using CO_2. Injection pressure is 1,000 psia, and turbine inlet pressure is 3691 psia. These pressures include through the rock pressure drop, but not well casing pressure drop. The turbine inlet temperature is 269 deg F, even though bottom hole temperature is 429 deg F.

The effective "earth cycle efficiency" comparing the heat removal rate from the earth to the net power is three times better (21% versus 7%) for CO_2 EGS at 30,000 ft than it was for water at 20,000 ft. The water EGS with 30,000 ft wells yielded a 400+ deg F ORC cycle inlet instead of 297 deg F, and an improvement from 7% to 10% ORC cycle efficiency, or only about 50% better. The change in water EGS cycle efficiency is not sufficient to justify the greater per well cost at 30,000 ft. In other words, for water EGS, the well cost goes up faster with depth than the cycle efficiency does – provided you are starting at a temperature where EGS is practical, which it certainly is at around 300 deg F.

WBS 1 - Exploration

There was no change in the cost for exploration for the Westover AFB location as a result of the change from Water EGS to CO_2 EGS. The cost for WBS 1 remains $3.71M.

WBS 2-3 - Reservoir Development

Significant changes occurred in WBS 2, Reservoir Development, and in particular WBS 2.3 drilling, as a result of the change to CO_2. The overall reservoir development cost of $1.1 Billion is staggering, but is dominated by the production well cost of $940M, which is driven almost totally by the stainless steel casing. Alternate (new) technology is required to enable a more cost effective CO_2 EGS. The WBS 2 cost result, with 6 steel injection wells, and 12 stainless steel production wells, both to 30,000 ft, is provided in the table below:

Table 18: Cost Summary for WBS 2 - Reservoir Development, SOPO 2

WBS	*50 MW*				
2.0	**$1,132,274,373**	**Reservoir Development**			
2.1	**$1,000,000**	Reservoir Planning	**Learning Curve**		
2.2	**$1,000,000**	Reservoir Model Development (integrate test bore results)	**Mult**	**# @ 91**	**# @ 82**
2.3	**$165,059,106**	Injection Well Drilling	**6**	**$31,803,296**	**/well**
		Big Bore, 30 kft, In Steel	**0.865**	**3**	**3**
2.4	**$940,315,268**	Production Well Drilling	**12**	**$93,008,434**	**/well**
		Small Bore, 30 kft, in Stainless: $91M, +$2M for dual completion	**0.843**	**3**	**9**
2.5	**$12,000,000**	Hydraulic stimulation	**6**	**$2,000,000**	**/well**
2.6	**(included)**	Intangible Drilling Costs (Mud / Temporary Equipment / Removal)			
2.7	**(included)**	Special Sand / Fluid Injection (Hold Fractures Open)			
2.8	**(included)**	Special Sealing Fluid Injection (probably more for CO2 system)			
2.9	**$0**	Production pumps	**0**	**$600,000**	**/well**
2.10	**$3,000,000**	Specialized logging	**4**	**$750,000**	**/well**
2.11	**$3,000,000**	Coring and leak-off testing	**4**	**$750,000**	**/well**
2.12	**$1,800,000**	Post-completion testing	**18**	**$100,000**	**/well**
2.13	**$5,000,000**	System circulation testing prior to plant start-up	**4**	**$1,250,000**	**/module**
2.14	**$100,000**	Water Well Drilling	**4**	**$25,000**	**/well**

The most significant feature of the CO_2 system design is, given that the size of the reservoir scales with the heat removal rate from the earth, it was possible to reduce from 41 total wells to 18 wells. The 18 wells are made up of six injection wells with conventional, carbon steel liners and a 10” diameter bottom hole, and twelve stainless steel production wells with an 8” diameter bottom hole.

The designs of the 30,000 ft injection and production wells are shown in the following figures. The detailed cost analysis for the 30,000 ft, 8 in stainless production wells and 30,000 ft, 10 in steel injection wells are provided in the tables that follow.

Table 19: Interval Cost Estimate for 8 Inch Wells, 30,000 Feet – SOPO 2

		GEECO Well Cost Breakdown						
		30,000 feet ending in 7-7/8" open hole						
		CO2 Cases						
		Interval Costs						
	Interval 1	**Interval 2**	**Interval 3**	**Interval 4**	**Interval 5**	**Interval 6**	**Total**	**%**
Casing Set Point	1,250	7,000	12,000	18,000	27,500	30,000		
Interval length, ft	1,250	5,750	5,000	6,000	9,500	2,500	30,000	
Length of casing run, ft	1,250	7,000	5,200	6,200	27,500	-		
Activity								
Drilling time (cost in $)	$215,787	$570,623	$562,753	$814,614	$1,437,910	$409,931	$4,011,618	4.5%
Tripping time (cost in $)	$11,068	$42,059	$106,254	$212,508	$450,626	$463,140	$1,285,655	1.5%
Bits and tools	$149,500	$468,250	$385,300	$494,820	$843,885	$244,755	$2,586,510	2.9%
Directional Drilling	$6,750	$94,600	$202,877	$123,500	$467,692	$133,333	$1,028,752	1.2%
Casing (including time to run)	$410,030	$3,427,533	$2,220,889	$1,059,789	$62,106,528	$0	$69,224,770	78.5%
Cement (including time)	$548,684	$737,944	$731,240	$490,006	$3,832,036	$0	$6,339,911	7.2%
Drilling fluids (incl. air and cleaning equipment)	$25,250	$51,300	$84,000	$99,000	$226,538	$64,583	$550,672	0.6%
Trouble	$96,836	$174,810	$21,741	$101,836	$33,612	$100,836	$529,671	0.6%
End of interval (logging, testing, and wellhead)	$157,169	$371,373	$381,995	$634,551	$501,366	$584,635	$2,631,089	3.0%
Total interval costs	**$1,621,075**	**$5,938,493**	**$4,697,049**	**$4,030,624**	**$69,900,194**	**$2,001,213**	**$88,188,648**	100.0%
		UpFront / Distributed Costs						
Rig mob and demob							$730,000	
Pre-spud engineering							$300,000	
Site prep, cellar, conductor							$85,000	
Contingency (10% of intangible drilling costs)							$1,704,786	
Total well cost							**$91,008,434**	
		Analysis of Interval Costs						
Drilling Costs	$505,192	$1,401,642	$1,362,925	$1,846,278	$3,460,264	$1,416,578	$9,992,878	11.3%
Drilling $/ft of interval	$404	$244	$273	$308	$364	$567	$333	
Casing & Cement Costs	$958,714	$4,165,478	$2,952,129	$1,549,795	$65,938,564	$0	$75,564,681	85.7%
Casing $/ft of casing set	$767	$724	$590	$258	$6,941	$0	$2,519	
Other Costs (not UpFront& Distrib)	$157,169	$371,373	$381,995	$634,551	$501,366	$584,635	$2,631,089	3.0%
Other Costs/foot	$126	$65	$76	$106	$53	$234	$88	
Total Cost per foot of Interval	$1,297	$1,033	$939	$672	$7,358	$800	$2,940	

Table 20: Interval Cost Estimate for 10 Inch Wells, 30,000 Feet – SOPO 2

	GEECO Well Cost Breakdown							
	30,000 feet ending in 10+" open hole							
	Interval Costs							
	Interval 1	**Interval 2**	**Interval 3**	**Interval 4**	**Interval 5**	**Interval 6**	**Total**	**%**
Casing Set Point	1,250	5,000	10,000	15,000	27,000	30,000		
Interval length, ft	1,250	3,750	5,000	5,000	12,000	3,000	30,000	
Length of casing run, ft	1,250	3,950	5,200	15,000	12,200	-		
Activity								
Drilling time (cost in $)	$345,320	$984,550	$554,840	$675,767	$1,316,613	$388,000	$4,265,090	14.8%
Tripping time (cost in $)	$10,913	$23,765	$89,240	$150,350	$222,010	$323,495	$819,772	2.8%
Bits and tools	$183,500	$350,500	$385,300	$417,600	$500,565	$174,825	$2,012,290	7.0%
Directional Drilling	$8,250	$103,700	$218,850	$130,000	$470,000	$141,000	$1,071,800	3.7%
Casing (including time to run)	$855,850	$2,848,020	$2,419,300	$2,597,120	$2,134,300	$0	$10,854,590	37.6%
Cement (including time)	$664,080	$937,240	$954,920	$3,386,340	$682,580	$0	$6,625,160	22.9%
Drilling fluids (incl. air and cleaning equipment)	$29,250	$61,125	$96,500	$103,333	$223,333	$62,000	$575,542	2.0%
Trouble	$95,840	$172,088	$21,520	$100,840	$33,280	$99,840	$523,408	1.8%
End of interval (logging, testing, and wellhead)	$157,432	$276,384	$327,158	$704,473	$390,707	$281,427	$2,137,580	7.4%
Total interval costs	**$2,350,434**	**$5,757,371**	**$5,067,628**	**$8,265,823**	**$5,973,388**	**$1,470,587**	**$28,885,232**	100.0%
	UpFront / Distributed Costs							
Rig mob and demob							$730,000	
Pre-spud engineering							$300,000	
Site prep, cellar, conductor							$85,000	
Contingency (10% of intangible drilling costs)							$1,803,064	
Total well cost							**$31,803,296**	
	Analysis of Interval Costs							
Drilling Costs	$673,073	$1,695,728	$1,366,250	$1,577,890	$2,765,801	$1,189,160	$9,267,901	32.1%
Drilling $/ft of interval	$538	$452	$273	$316	$230	$396	$309	
Casing & Cement Costs	$1,519,930	$3,785,260	$3,374,220	$5,983,460	$2,816,880	$0	$17,479,750	60.5%
Casing $/ft of casing set	$1,216	$958	$649	$399	$231		$465	
Other Costs (not UpFront or Distrib)	$157,432	$276,384	$327,158	$704,473	$390,707	$281,427	$2,137,580	7.4%
Other Cost $/ foot	$126	$74	$65	$141	$33	$94	$71	
Total Cost per foot of Interval	$1,880	$1,535	$1,014	$1,653	$498	$490	$963	100.0%

Note from the tables that the 8” diameter stainless steel well has a cost that is three times that of the 10” diameter steel well at 30,000 ft. The difference is, of course, the cost of stainless steel liners used for the production wells. The liner cost is 78% of total cost for the 30,000 ft stainless steel design. Fortunately, it was possible, due to the better pressure drop characteristics of CO_2 and reduced mass flow from this very efficient geothermal system, to use the smaller size 8” production well. The cost of a 10” stainless steel well was estimated at over $140M per well, 50% more than the 8” version.

WBS - 3 Reservoir Pumping

The WBS 3 total cost is $183M and the summary table is provided below. WBS 3 for SOPO 2 assumes that CO_2 for the Project, the dominant cost element in the WBS 3 for CO_2 category, is purchased at market rates.

Table 21: Summary Costs for WBS 3 - CO_2, SOPO 2

WBS	Cost	Item	Basis / Comment
3.0	**$183,770,000**	CO_2	MT Required
3.1	**$175,200,000**	Filling CO_2	**0.73**
3.2		Price / Ton (In Massive Quantity)	**240**
3.3			
3.4	**$2,000,000**	Electric Blower to Start Thermal Siphon?	
		1000 hp multi-stage compressor, electric drive (Solar Turbines)	
3.5	**$3,580,000**	Diesel Genset for Backup Power	ROM
		Details (for backup genset as well)	
		Cost of 1 OP Dual Fuel Engine & Generator plus Auxiliaries & Controls	1790000
		Power Level	1506
		Specific Fuel Consumption	6400
		Fuel Price ($/mmBTU)	4
			2
		Hours of operation per year	8000
3.6	**$400,000**	Filtration	ROM
3.7	**$90,000**	Freeze Protection	ROM
3.8	**$2,500,000**	CO_2 Compression (Local Dewar, LP Transfer Pump, HP Liquid Pump)	
3.9	**$8,127,206**	Fuel & CO_2 Top Off	
	$827,206	**NG Fuel Costs (Not Summed Above)**	TPD Required
	$7,300,000	**Per Year** CO_2 **Top Off Costs (Not Summed Above)**	66.7
		Price / Ton (Not In Massive Quantity)	300
	$240,960	**Engines Maintenance Costs (Not Summed Above)**	0.01
		Based on $.01/kW-hr. OP engine: $.01 x (1506x3) x 8000. 32/40: $.01 x (5975x4) x 8000	

The decision to use deeper wells for SOPO 2 is driven by the desire to not only reduce the number of wells and associated casing cost, but also to have the highest possible earth cycle efficiency by accessing the higher temperature resource deeper beneath the earth's surface. This results in the smallest reservoir and smallest amount of purchased CO_2. Based on quotes and discussions with gas suppliers, a price of $240 / ton delivered was used for CO_2 for reservoir filling. A higher price is used for reservoir top off. CO_2 is transported at 0 deg F, 300 psia. Later in the filling process, CO_2 is required at much higher pressure, necessitating $2.5M of topside equipment consisting of a large Dewar, transfer pump, refrigeration (to reduce boil off) and a high pressure pump (for injection).

There was debate on the need for a so-called "starter motor," that is, a way in which to start the thermal siphon effect, for the CO_2 EGS. The large thermal siphon (3700 psig) predicted will only exist when there is a temperature difference, resulting in a large density difference, in the injection well and production well. At steady state, with no flow, there would be no difference in temperature profile, and therefore no density or pressure difference. It is likely, but unproven, that even the relatively low flow rate associated with filling will keep the injection well cooler than the production well. This should be enough to enable the flow to self start, but since this is unproven, a "starter motor" is also included in WBS3. This starter motor is similar to a natural gas pipeline compressor. Other elements of the WBS 3 spreadsheet are consistent with the water EGS.

WBS 4-6 - Energy Conversion and Power Distribution Equipment

The WBS 4 costs for the direct turbo expander based energy conversion are summarized below and total $70M, a significant reduction over the $151M cost of the 50 MW ORC stated in WBS 4 Energy Conversion Equipment for SOPO 1. Note that the $400/kW for rotating equipment is captured above as WBS 4.1 and 4.6 Non-Recurring Engineering.

Table 22: Summary Costs for WBS 4 - Power Generation, SOPO 2

WBS	*50 MW*	
4.0	**$70,000,000**	**Power Generation**
		(ORC or ORC and CO_2 Direct Turbine, As Applicable)
4.1	**$6,000,000**	Rotating Equipment (Turb / Gen / Pump)
4.2	**$11,000,000**	CO_2 Condenser / Cooler
4.3	**$5,000,000**	Electrical
4.4	**$12,000,000**	Cooling Tower / Fans / Pumps / Packaging / BOP
4.5	**$2,000,000**	Consumables
4.6	**$14,000,000**	Non Recurring Engineering (NRE)
4.7	**$9,000,000**	Installation
4.8	**$7,000,000**	On Site Integration
4.9	**$4,000,000**	Testing

The CO_2 EGS has major advantages, and a few disadvantages, as it relates to energy conversion equipment. The major advantages, already discussed at a high level, stem from the ability to make power directly from the EGS working fluid (CO_2).

In a conventional EGS, power is made from heat, and large high pressure heat exchangers are required to transfer the heat from the hot brine to the boiler of the Organic Rankine Cycle (ORC) equipment. The small thermal difference between the heat input temperature and the heat rejection temperature result in relatively low cycle efficiency, as discussed in the WBS4 section of SOPO 1. It also happens to result in very large feed pump power within the ORC, and similarly large parasitic losses on the cooling side.

Turbine Air Systems, working with established turbo machinery / turbo-expander suppliers, was able to develop a novel approach for energy conversion in the CO_2 EGS. This system is shown graphically below. As shown in the diagram, the conventional Rankine cycle is inverted. In practice, the "pump" is replaced by the CO_2 thermal siphon. And, since this is really a supercritical fluid in most if not all parts of the cycle (critical temperature 88 deg F, 1100 psi), in effect, the Organic Rankine Cycle has become a supercritical Brayton cycle, with compression provided by thermal siphon. Regardless of how we describe it, we have eliminated components and reduced cost.

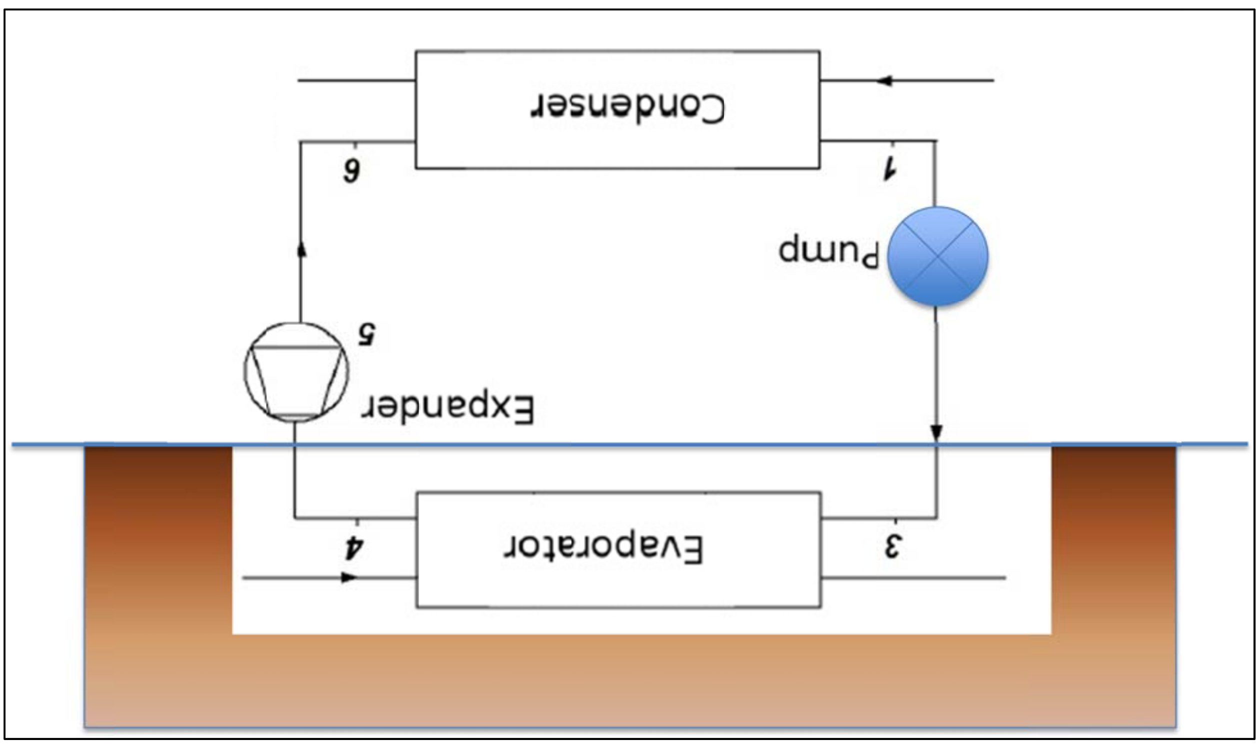


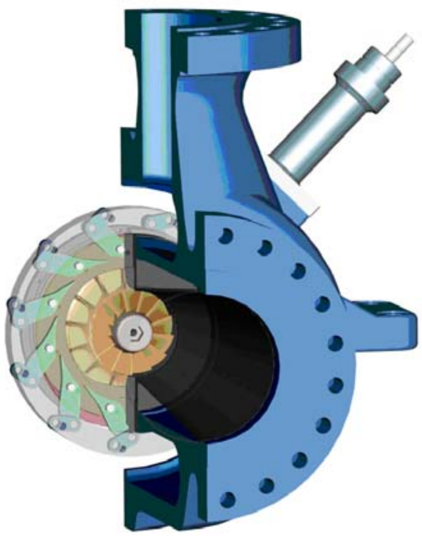
Figure 15: Novel Approach to Energy Conversion for CO_2 EGS: Inverted Organic Rankine Cycle

A bulleted summary outlining the design approach and challenges is shown below.

CO_2 Turboexpander Design Challenges

- CO_2 Turboexpander - Generator Conceptual Design:
  - 50.0 MW total direct CO_2 Turboexpander - generator modules
    - ~3000 psia inlet pressure
    - ~1000 psia exhaust pressure design (600 – 1600 psia range)
    - Temperature @ 225^0 F
- "Not developed yet" Challenges:
  - Casing design and bolting configuration - High inlet and outlet pressure
  - Inlet Guide Vane (IGV) clamping and actuation;
  - Thrust management during start-up, normal operation, and shutdown;
  - Shaft sealing configuration.
  - Metallurgical concerns due to wet CO_2
- Propose to Leverage - existing technology
  - (4) EG-6 Turbo – expanders
    - Wheel = 19.6 inches, speed = 7300 rpm
    - Expected efficiency = 87%, calculations at 85% for 2% safety margin
    - Expected gas power = 19,470 HP
    - Expected net generator output power = 13,800 kW per unit
    - 55.0 MW total for (4) units @ Budgetary Pricing ~ $400-500/kW

A solid model cutaway of the new turbo expander design is provided below.



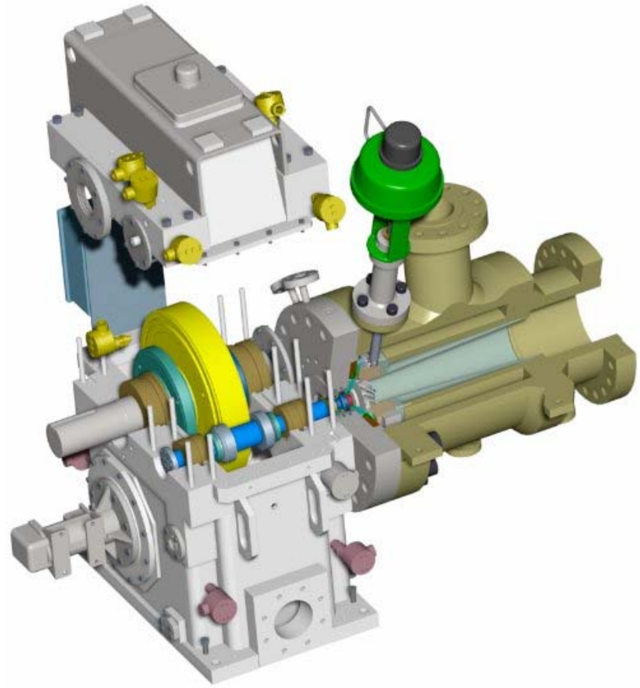


Figure 16: Solid Model Renderings of CO2XX Turbo Expander

WBS 7-10 - Project Management, Permitting, Operation

Changes to WBS 7 to 10 between SOPO 1 and SOPO 2 are mostly associated with the smaller land area, smaller total project (in terms of number of wells drilled), and differences in permitting challenges having to do with the use of CO_2 vs. water as an EGS fluid.

The net result is that costs in these areas are about ½ of what they were for SOPO 1, and include the following items:

- WBS 7: Top of well sites and facilities to house surface elements;
- WBS 8: Land acquisition and / or land use w/ royalty agreements;
- WBS 9: Federal, State local and private (stakeholders) permits, approvals, incentives; and
- WBS 10: Project management.

WBS 7 – Top of Well Sites and Facilities

WBS 7 costs total $8M and are summarized in the table below.

Table 23: Summary Costs for WBS 7 - Top of Well Site and Facilities, SOPO 2

WBS 7		
7.0	**$8,005,000**	**Top of well sites and facilities to house surface elements of 50 MW CO2 EGS**
7.1		**Design**
7.1.1	**$325,000**	Engineering: Survey of property, soil borings, design of topography, stormwater management, standard building utility connections
		Cost is largely dependent on size and number of structures and terrain.
7.1.2	**$30,000**	Design of foundations for external equipment
		Cost will vary depending on number of external equipment pieces and repetitive des
7.1.3	**$50,000**	Engineering for construction of CO2 storage containment: Civil, Structural and Fire Protection.
7.2		**Construction**
7.2.1	**$4,000,000**	Major Buildings
		This estimate provides for a building of approxiamtely 32,000 square feet along with essential aspects of insulation, HVAC, electrical, plumbing, control room, office space, bathrooms, and security.
		The weight of building will be substantial with interior components. The foundation cost is largely variable based on soil stability present on the site and weight of the mechanical components chosen for the project.
7.2.2	**$400,000**	Construction of Concrete Pads / Foundations for External Equipment
		Place holder: Rough Estimate. Need to research: size and number of pads/foundations. All are currently unknown. Does not include pile driving for weak soil stability.
7.2.3	**$400,000**	External Equipment Shelters
		Due to the design of a network of wells, the potential for up to 12 equipment shelters of ranging sizes may be necessary during winter conditions dependant on the efficiency of the layout of the well heads, piping network and pump components.
		Does not include electrical connections cables, connects or fixtures
7.2.4	**$700,000**	Earthwork for stormwater, utilities and conduit trenches between main building and well heads; exclusive of building and foundation construction
7.2.5	**$100,000**	Construction of CO2 pipe network and associated infrastructure
7.2.6	**$2,000,000**	Installation of manufactured CO2 and O2 containment tanks or construction of a custom storage facility

WBS 7 Notes:

1. The CO_2 analysis provides a reduction in cost due to the elimination of construction for a well water source. This is reflected in the drilling costs.
2. See SOPO 1 for locations of utility access points (transmission lines and substations.)

3. A rough estimate for the surface CO_2 storage tank has been provided for this cost analysis. If the required storage volume of liquified CO_2 is greatly increased, the cost of a custom built storage tank may also greatly increase.
4. Costs are based on RSMeans Building Construction Cost Data 2011 and experience and projects that Fort Point Associates has participated in.

WBS 8 – Land Acquisition and/or Land Use with Royalty Agreements

WBS 8 for SOPO 2 totals \$6.9 M and is summarized in the table below. The lower cost of WBS 8 for SOPO 2 versus SOPO 1 is a result of the smaller number of wells and therefore associated land use, required for the CO_2 EGS system.

Table 24: Summary Costs for WBS 8 - Land Acquisition, SOPO 2

8.0	**\$6,985,000**	**Land acquisition and / or land use w/ royalty agreements**
8.1		**Primary Site Acquisition**
8.1.1	**\$100,000**	Consulting Costs for property locating and feasibility studies
8.1.2	**\$6,750,000**	Vary by size of facility (acres) and value of land; Assume average cost
		@ \$10,000 per acre for 1,500 acres = **\$15,00,000**
		@ \$5,000 per acre for 500 acres = **\$2,500,000**
8.1.3	**\$135,000**	Closing Costs (2% ±)

WBS 9 - Federal, State, Local and Private (Stakeholders) Permits, Approvals, and Incentives

The best estimate of WBS 9 regulatory requirements costing \$4.5M as shown in the table below. WBS 9 costs are higher for SOPO 2 than SOPO 1 because of the added complexity of permitting a CO_2 EGS , on top of the fact that this the first EGS of any type in Massachusetts. The added cost is mostly associated with uncertainty with regard to how CO_2 (a know greenhouse gas) will be treated from a permitting standpoint in this application.

Table 25: Summary Costs for WBS 9 - Federal and State Permits, SOPO 2

WBS	Cost		
9.0	$4,530,000	**Federal, state, local and private (stakeholders) permits, approvals incentives leading to and enabling construction and operation of CO2 EGS and H2O EGS applications at 50 MW;**	
9.1		**Consulting efforts toward receiving Permit and Approvals**	
9.1.1	**$700,000**	Research and Planning of approval process, coordination with project team, permit expediting	
9.1.2	**$300,000**	Stakeholder and Regulatory: Assessment, design of strategy, informational meetings, media and communications plan	
9.1.3	**$150,000**	Contingency for Education/Outreach with local and state officials (including fees for agency expert consultation)	
9.2		**Permit and License Fees**	
9.2.1	**$50,000**	Building Permit Fee (Estimate based on City of Chicopee fee of $0.60/SF plus specific fees)	
		Maximum Building Permit Fee is based on a cost of $7 per $1,000 of building code specific construction cost of surface building construction only.	
		Minimum Building Permit Fee is based on the City of Chicopee building permit cost structure ($0.50/sf general permit cost, $0.10/sf electrical fee, plus other fees)	
9.2.2	**$30,000**	Other Permit Fees (Rough Estimate)	
		This includes the permit application fees of the "known permits" (minimum), and some "Other Potential Permits" (maximum) as shown in the tables below	
9.2.3	**$500,000**	Interconnection with Electric Grid (Fees and Two Studies)	
9.2.4		GHG Reporting Costs	(natural gas and geothermal)
9.3	**$800,000**	**Mitigation Requirements**	
		To be further determined when interaction is appropriate with reviewing agencies, community groups and abutters	
9.4	**$2,000,000**	**Contingency for appeals and other stakeholder intervention**	

WBS 10 – Project Management

WBS 10 project management costs total $10.7M and are very similar in format to those of SOPO 1, and scaled based on the size of the project, which is smaller due to fewer wells. This results in reduced drilling and construction time, and therefore reduced project management scope. WBS 10 costs are provided in the table below.

Table 26: Summary Costs for WBS 10 - Project Management, SOPO 2

WBS	Cost	PROJECT MANAGEMENT							
10.0	$ 10,908	Year	1	2	3	4	5	6	7
10.1	$ 260	PLANNING & SCHEDULING	40	40	40	40	40	40	20
10.2	$ 105	DOCUMENT CONTROL & DESIGN	40	20	10	10	10	10	5
10.3	$ 90	QUALITY ASSURANCE	-	-	20	20	20	20	10
10.4	$ 3,750	PROCUREMENT & FIELD CONTRACTING	300	300	600	750	750	750	300
10.5	$ 2,325	CONSTRUCTION MANAGEMENT	-	300	450	450	450	450	225
10.6	$ 88	MANAGEMENT INFORMATION SYSTEM	30	10	10	10	10	10	8
10.7	$ 60	INSPECTION & TESTING	-	-	13	13	13	13	10
10.8	$ 4,229	INSURANCE, WORKPLACE SAFETY	-	-	875	875	875	875	729
		Total:	410	670	2,018	2,168	2,168	2,168	1,308

WBS 10 Notes:

1. Reservoir development is estimated at 4 years and 4 months (provided by Impact Technologies.)
2. After drilling and major construction are complete, additional time for project management is included to account for aqueous phase of the final wells. Six months for aqueous phase is assumed.

SOPO 2.0 50 MW CO_2 EGS Cost Summary Results

The capital cost for all the items associated with the construction of the 50 MW EGS system are rolled up into a higher level spreadsheet, and the levelized cost of electricity is calculated. Using the levelized electricity rate, the profit or loss of the proposed venture is calculated.

The total capital cost of $1.44B for the 50 MW CO_2 EGS is summarized by WBS item number in the table below.

Table 27: Cost Summary for WBS 1 – 10 – 50 MW CO_2 EGS, SOPO 2

WBS	Capital Cost	WBS Element
	50 MW Net	
1.0	$3,710,000	Resource ID / Analysis
2.0	$1,132,274,373	Reservoir Development
3.0	$183,770,000	Fluid Management & CO2 (filling)
4.0	$70,000,000	Power generation
5.0	$3,500,000	Integration / Distribution (local)
6.0	$18,000,000	Integration / Distribution (grid)
7.0	$8,005,000	Topside Structures
8.0	$6,985,000	Land Acquisition / Land Use
9.0	$4,530,000	Permits / Approvals
10.0	$10,907,917	Project Management
Total	$1,441,682,290	

As can be seen, the capital cost for the Project is much greater than for SOPO 1.0. The total cost is \$1.44B, nominally 50% more than the \$950M of SOPO 1 50 MW Gross water EGS. Though the power generation costs are lower, they are more than offset by the higher fluid management cost, most of which is the purchase price of CO_2. More significantly, though the number of wells has been reduced from 32 to 18, the reservoir development costs have increased from \$699M to \$1.132B. In rough terms, this is about an average per well cost increase of a factor of three: \$699M for 32 wells of SOPO 1 results in an average of \$22M per well; \$1.132B for 18 wells of SOPO 2.0 averages \$63M per well.

The SOP0 2.0 summary spreadsheet for the 50 MW gross geothermal system with purchased CO_2 and stainless steel liners on the production wells is provided below:

Table 28: Summary Spreadsheet for 50 MW CO_2 EGS, SOPO 2

Parameters:	CO2 EGS		Comment	
Geothermal Power (Net)	50	MW	Geothermal Net Power	
Total Net Power	50	MW	Yearly Total (Not Including Filling)	
CO2 System Net Power (extra to be sold)	0	MW	(from WBS 3)	
Cost of Electricity (retail)	$167	$/MW-hr	(US DOE EIS 2008 MA)	
Cost of Electricity (wholesale)	$81	$/MW-hr	(ISO NE 2008 Hub Price)	
MA Renewable Market Class 1 RPS	$13	$/MW-hr		
Capital Cost	$1,441,682,290	(roll up)	(from capital sheet)	
Cost of Capital	7.0%	(high)	(variable)	
	20	(30 year default)		
Annual Capital Cost	$136,084,609		(calculation)	
O&M Cost	$10	$/MW-hr	2007 GRC Presentation	
Availability	99.5%	(uptime)	(guess)	
<u>Cost Item</u>	<u>$</u>			
Annual Capital Cost	$136,084,609		Escalation Rate (%/year)	
O&M Cost	$4,358,100		2.0%	
O&M Cost Engines	$240,960			
Purchased Costs (Fuel / CO2)	$8,127,206		1.811361584	(30 year)
Total Annual Cost	$148,810,875			
	<u>Revenue (1st Full Year)</u>		<u>Revenue (30th Year)</u>	
		Percent	Impact of Escalation in Electric Costs	
Offset of Retail Electricity	$36,390,135	50.0%	$65,915,693	
Wholesale Electricity	$17,650,305	50.0%	$31,971,084	
MA Renewable Market Class 1 RPS	$5,665,530		$5,665,530	
Renewable Investment Tax Credit	$8,716,200		(Zero After 10 Years)	
Total Revenue	$68,422,170		$103,552,307	
Profit / Loss	($80,388,705)		($45,258,568)	

As can be seen, this project would lose even more money than the baseline SOPO 1 water EGS case. The yearly loss increases from $35M to over $80M, again, driven almost completely by the cost of stainless steel liners for the production wells and the cost of CO_2 itself. It is doubtful with this set of technology assumptions, in particular stainless steel liners, that CO_2 EGS would be financially viable at any location, but it is clearly very, very far from financially viable in Western Massachusetts.

The next step, SOPO 3, is to assess the impact of technology, to include "drilling" technology and CO_2 generation technology on the cost of the CO_2 EGS in this location. SOPO 4 will address other locations.

SOPO 3 - Impact of Technology, to CO_2 Generation Technology and Drilling Technology on C02 Cost Baseline Results at Westover AFB

The impact of technology to the CO_2 EGS, SOPO 3, per the statement of project objectives was to consider drilling technology, and CO_2 generation technology. As it turns out, while there are drilling technologies, including those invested in by DOE, that improve drilling rate and hence reduce time on site, the area was broadened to include materials technology – once the results from SOPO 2 were seen on material costs in casing.

As part of the technology evaluation process, since there are so many technologies of differing maturity and differing program impact, the decision was made to consider only those technologies in a quantitative manner with a relatively mature Technology Readiness Level (TRL).

The concept of TRL has been adopted by NASA, DoD, DoE, and many others in Government and Industry. The charts are adapted depending on the end user, a flight (missile) operations TRL "thermometer" is shown at right, and a commonly used set of definitions of TRL, from DOE, is presented below.

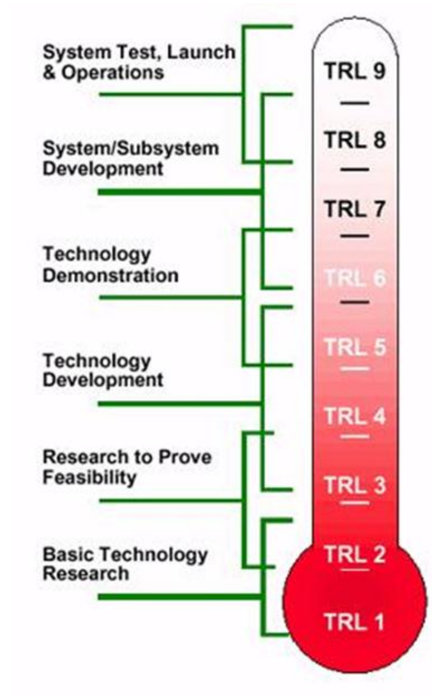


Figure 17: TRL Levels

Table 29: Definition of TRL Levels

Technology Readiness Level	Description
TRL 1.	Scientific research begins translation to applied R&D - Lowest level of technology readiness. Scientific research begins to be translated into applied research and development. Examples might include paper studies of a technology's basic properties.
TRL 2.	Invention begins - Once basic principles are observed, practical applications can be invented. Applications are speculative and there may be no proof or detailed analysis to support the assumptions. Examples are limited to analytic studies.
TRL 3.	Active R&D is initiated - Active research and development is initiated. This includes analytical studies and laboratory studies to physically validate analytical predictions of separate elements of the technology. Examples include components that are not yet integrated or representative.
TRL 4.	Basic technological components are integrated - Basic technological components are integrated to establish that the pieces will work together.
TRL 5.	Fidelity of breadboard technology improves significantly - The basic technological components are integrated with reasonably realistic supporting elements so it can be tested in a simulated environment. Examples include "high fidelity" laboratory integration of components.
TRL 6.	Model/prototype is tested in relevant environment - Representative model or prototype system, which is well beyond that of TRL 5, is tested in a relevant environment. Represents a major step up in a technology's demonstrated readiness. Examples include testing a prototype in a high-fidelity laboratory environment or in simulated operational environment.
TRL 7.	Prototype near or at planned operational system - Represents a major step up from TRL 6, requiring demonstration of an actual system prototype in an operational environment.
TRL 8.	Technology is proven to work - Actual technology completed and qualified through test and demonstration.
TRL 9.	Actual application of technology is in its final form - Technology proven through successful operations.

While no one has built a 50 MW EGS system yet, and certainly not a CO_2 EGS, at the component level, everything discussed to this point in the report, i.e. for SOPO 1 and SOPO 2, has been at TRL9. This modification to the TRL approach, to use the TRL for component technology, not the system, was necessary given the relatively immature state of EGS, in particular CO_2 EGS.

For example, while no one has done a production well for a CO_2 EGS with a stainless steel liner, to 30,000 ft, in granite, the parts of this problem at the component level have been demonstrated in the field and proven successful. Stainless liners are used in EOR applications or other corrosive environments today. Drilling technology to 30,000 ft (and 400+ deg F) certainly exists, the tubulars for the casing are available in the sizes used in our designs, and drilling of granite, while difficult and slow, is a proven capability.

For SOPO 3, we are to apply "technology" to the design and assess the impact on cost. While it is possible to qualitatively discuss the impact of a particular technology, more or less independently from the maturity of that technology, it is not fair / credible / consistent to attempt to do so in a quantitative manner. As a result, the team made the decision that the "technology" assessed quantitatively for SOPO 3 must be at a TRL level of 6, again with the modification being that this applied to the components, not to the CO_2 EGS system, which is of course nowhere near TRL6.

Given that "technology" would address the drilling cost (casing) for CO_2, a shallower EGS system would make sense for SOPO 3. The only reason we went to 30,000 ft for SOPO 2 was to get to high cycle efficiency, which would reduce the size of the reservoir and hence the number of wells, limiting the impact of the extreme cost of stainless liners.

The effect of more reasonable well depths was again assessed using the thermodynamic model. Wells to 20,000 ft were selected. The depth of 20,000 ft yielded of course the same bottom hole temperatures as for SOPO 1 (308 deg F). Due to the near isentropic expansion up the hole, top hole temperatures are much lower (180 deg F), but still more than sufficient to drive turbo machinery, with a 2400 psi thermal siphon. The combined effect was to greatly reduced well count, 9 injection wells and 16 production wells are used. Due to pressure drop concerns, with the lesser but still significant thermal siphon, the decision was made to use the large bore (10" nominal at depth) designs. The thermal model for Westover AFB, 20,000 ft, with CO_2 EGS working fluid is provided below.

Table 30: Thermodynamic Model for 20,000 feet CO_2 EGS in Western Massachusetts, SOPO 3

Assumptions:					Results:				
Surface Temperature = 66 deg F (yearly average)					Massflow			5815	LBM/SEC
Temperature Gradient =		1.21	deg F / 100' (Subir Report)		Heat Rate Extracted from Earth=			1120	MMBTU/hr
Isentropic Compression / Expansion on Way Down / Up				H Trb inlet	Power		DH Cooler	50	MW
1000 psia injection pressure (near optimum)				(BTU/lbm)			(BTU/lbm)	69097	hp shaft
50 MW Net				173.0	Earth System Cycle Efficiency		44.7	15.2%	
Turbine Efficiency =		80.0%	(isentropic)						
Down Hole (Injection Temperature) =			80	H Injection	H Ex Isen	H Ex	DH Turb	T Ex	T Sat Ex
			deg F	(BTU/lbm)	(BTU/lbm)	(BTU/lbm)	(BTU/lbm)	(deg F)	(deg F)
carbon dioxide		Unit system:	E	119.9	162.5	164.6	8.4	83	82
Pressures Shown due not include surface									
piping or well pipe pressure drop				H Bottom Inj	H Bottom Prod.	DH Bottom	S Turb	S Top Inj	S Bottom
Average Density (bottom, lbm/ft^3) =			49.9	(BTU/lbm)	(BTU/lbm)	(BTU/lbm)	BTU/lbm R	(BTU/lbmR)	BTU/lbm R
				145.5	199.0	53	0.3796	0.3011	0.3796
Increment =	1000	ft per calculation							
				Pressure Drop Inj to Production (@ Bottom) =			400	psi	
			Injection Wells				Production Wells		
Calc Step	Depth		Temp (Inj)	Density (down)	Injection Well	Temp @ Depth	Temp Up	Pressure	Density
	(feet)	(m)	F	(lbm/ft^3)	(psia)	F	F	(psia)	(lbm/ft^3)
0	0	0	80.0	43.9	1000	66	179	2401	30.0
1	1000	305	88.4	45.3	1305	78	188	2617	31.0
2	2000	610	95.8	46.4	1619	90	197	2839	32.0
3	3000	914	102.4	47.4	1942	102	205	3068	33.0
4	4000	1219	108.5	48.2	2271	114	213	3303	33.8
5	5000	1524	114.2	49.0	2605	127	221	3544	34.7
6	6000	1829	119.6	49.7	2946	139	228	3790	35.5
7	7000	2134	124.7	50.3	3290	151	235	4042	36.2
8	8000	2438	129.6	50.9	3640	163	242	4298	37.0
9	9000	2743	134.2	51.5	3993	175	249	4560	37.6
10	10000	3048	138.7	52.0	4351	187	255	4826	38.3
11	11000	3353	143.0	52.5	4712	199	261	5096	38.9
12	12000	3658	147.1	53.0	5076	211	267	5370	39.5
13	13000	3962	151.2	53.4	5444	223	273	5649	40.1
14	14000	4267	155.1	53.9	5815	235	278	5931	40.7
15	15000	4572	158.8	54.3	6189	248	283	6218	41.2
16	16000	4877	162.5	54.7	6566	260	289	6507	41.7
17	17000	5182	166.1	55.1	6945	272	294	6801	42.2
18	18000	5486	169.6	55.4	7328	284	299	7097	42.7
19	19000	5791	173.1	55.8	7713	296	303	7397	43.2
20	20000	6096	176.4	56.2	8100	308	308	7700	43.7

Injection pressure is 1,000 psia, and turbine inlet pressure is 2400 psia. These pressures include through the rock pressure drop, but not well casing pressure drop. The turbine inlet temperature is 180 deg F, even though bottom hole temperature is 308 deg F.

The “earth cycle efficiency,” a comparison of the heat removal rate from the earth to the net power output, is twice (15% versus 7%) the rate of water EGS at the same depth. This earth cycle efficiency is consistent with a 9 injection well, 16 production well design.

WBS 1 - Exploration

There were no changes to WBS 1 for the CO_2 EGS. The cost for WBS 1 remains $3.71M.

WBS 2 - Reservoir Development

The total WBS 2 cost for reservoir development is now $861M. The impact of available TRL 6 component technology has the net result of lowering the reservoir development cost by 24%, from what was $1.132B, for a system with fewer wells. The continued development of other technology, not included herein since it was not TRL 6, would have further impact. Even with the material technology applied, casing and cement cost is still 68% of well costs. Reduction of this component, probably via some radically different approach to well construction, could have the greatest impact. WBS 2 costs are summarized in the table below.

Table 31: Summary Costs for WBS 2 - Reservoir Development, SOPO 3

WBS	50 MW				
2.0	**$861,853,138**	**Reservoir Development**			
2.1	**$1,000,000**	Reservoir Planning	**Learning Curve**		
2.2	**$1,000,000**	Reservoir Model Development (integrate test bore results)	**Mult Fac**	**# @ 91**	**# @ 82**
2.3	**$243,101,549**	Injection Well Drilling	**9**	**$27,011,283**	**/well**
		Big Bore, 20 kft, In Steel	**0.85**	**3**	**6**
2.4	**$585,151,588**	Production Well Drilling	**16**	**$36,571,974**	**/well**
		Big Bore, 20 kft, Cladded, Dual Completion ($34M + $2M)	**0.836875**	**3**	**13**
2.5	**$18,000,000**	Hydraulic stimulation	**9**	**$2,000,000**	**/well**
2.6	**(included)**	Intangible Drilling Costs (Mud / Temporary Equipment / Removal)			
2.7	**(included)**	Special Sand / Fluid Injection (Hold Fractures Open)			
2.8	**(included)**	Special Sealing Fluid Injection (probably more for CO2 system)			
2.9	**$0**	Production pumps	**0**	**$600,000**	**/well**
2.10	**$3,000,000**	Specialized logging	**4**	**$750,000**	**/well**
2.11	**$3,000,000**	Coring and leak-off testing	**4**	**$750,000**	**/well**
2.12	**$2,500,000**	Post-completion testing	**25**	**$100,000**	**/well**
2.13	**$5,000,000**	System circulation testing prior to plant start-up	**4**	**$1,250,000**	**/module**
2.14	**$100,000**	Water Well Drilling	**4**	**$25,000**	**/well**

As has been reviewed to this point, reservoir development cost is driven by drilling cost, to include:

- Number of Wells
- Depth
- Drilling Difficulty / Technology
- Casing Material / Technology

The greatest savings / potential of the CO_2 EGS comes in at the first bullet, number of wells. Higher cycle efficiency means fewer wells, even at modest depth. Sixteen production wells and 9 injection wells are used, to 20,000 ft.

There is great discussion and focus from DOE on drilling technology. Even before seeing the significant costs of the work herein, this was justifiably a “problem” and investment by DOE in this area will have great payoff. Spallation, investigated by Potter et al, has demonstrated significantly increased drilling rates, in the earth, but not to the depths required our EGS designs. Abrasive cutting, investigated by Oglesby et al, who is also a member of the team on this contract, also has demonstrated significantly increased cutting rates. Investment in these areas, or in other cutting technologies that increase drilling speed and therefore reduce rig time on site, will on a near linear basis decrease the costs of those components of the drilling operation.

Both the abrasive and spallation techniques also lend themselves to smaller "micro-bore" holes, the former more than the latter. The use of micro bores (2" or less in diameter) and directional drilling could greatly increase the effectiveness of the fractured zone and contact with the reservoir.

The abrasive and spallation based drilling technologies were evaluated, including the change to the fracture approach / reservoir design that could be implemented via these technologies, but in the end these technologies were not deemed to be at a TRL level of 6 at this time. As a result, the benefit of faster drilling and alternative reservoir geometries is NOT included in the quantitative SOPO 3.0 results herein.

Casing material technology is required to lower casing costs for the corrosive CO_2 / H_2O mixture. Various approaches were evaluated, some of which are not at TRL 6, but the decision was made to use "clad liners" on the casing. It is possible to use plating / stainless as a liner material in lieu of solid stainless steel casing, but the more likely approach, at least at the relatively modest maximum temperatures (308 F) is a composite lining. This technology is at TRL 6 or better now. Several companies offer a fiberglass lined tubular for the EOR industry now, but just not in the sizes we require for the CO_2 EGS. Clad liners have a cost premium over unlined tubulars, and in the models herein that premium is conservatively estimated at four times conventional steel fabricated assembly cost (the actual prices for clad liners in the sizes currently available are closer to two times conventional). Even at four times conventional, this is much lower than the upcharge for stainless casing, which was 24 times conventional steel fabricated assembly cost.

The cost model uses this dual clad lined tubular for production wells and conventional steel casing for the injection wells. Clean dry CO_2 is not corrosive, so this seems like a reasonable area to accept a small amount of risk to generate significant savings. Note: The high costs of SOPO 2.0 also assumed conventional steel casing for injection wells.

At a level nearer TRL 1, there might be even greater savings if a liner technology or drilling technology were developed that would allow constant or nearly constant diameter to depth. Currently, the bit is about the same size (or slightly smaller) than the hole it cuts. Since the casing has to fit smoothly inside this hole, we get the familiar stepped well casing construction. In all cases herein we are starting at the surface with a bit diameter of 4 or 5 FEET in order to end up with a hole at depth that is 8 to 10 INCHES. If there was a way to form a casing as you drill, and to extract the tool through a smaller diameter hole than it cuts, then a fundamental change to the drilling cost model would occur which might be VERY beneficial. Think of this as the vertical equivalent of tunneling technology, but at a much smaller size. There are "monobore" drilling techniques in much smaller diameters that have been studied and implemented to a limited degree in oil and gas.

SOPO 3 Specific Design and Results

Significant changes occurred in WBS 2, Reservoir Development, as a result of technology and in particular WBS 2.3 drilling as a result of the change to CO_2. Nine injection wells with conventional, carbon steel liners and a 10" diameter bottom hole and sixteen clad production wells with a 10" diameter bottom hole and dual completion are required.

The designs of the 20,000 ft injection and production wells are shown in the following figure, with the exception of the cladding on the production wells, this is essentially the same design as the SOPO 1.0 EGS Water Injection Wells.

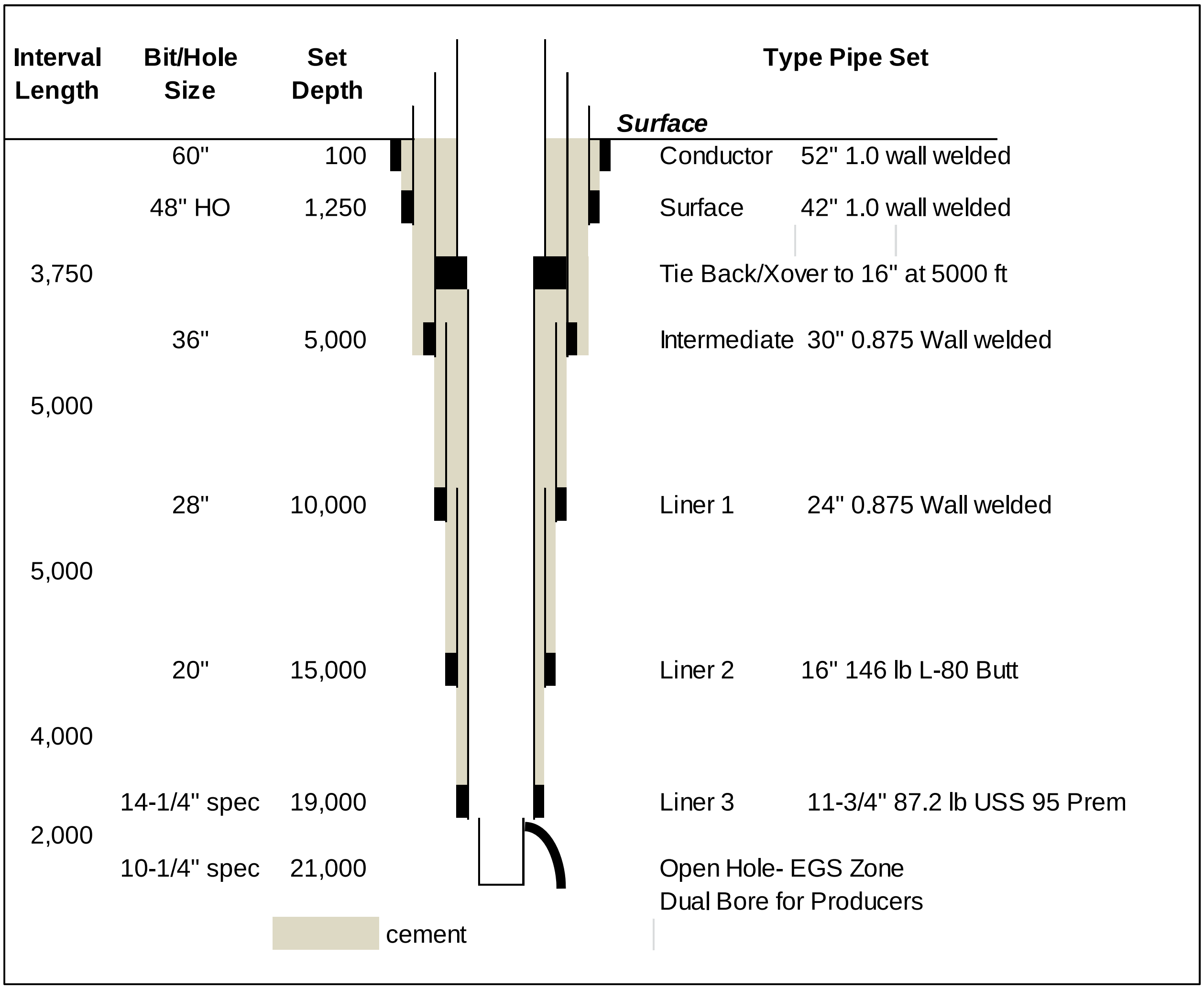


Figure 18: 10 Inch, 20,000 feet Well Design for CO_2 EGS Injection and Production Wells, SOPO 3

The cost breakdown for this well design is provided in the following tables. The first table, for the injection wells, is essentially the same as for the SOPO 1 injection wells. The second table reflects the dual clad lining.

Table 32: Interval Cost Estimate for 10 inch, 20,000 foot Steel Wells, SOPO 3

20,000 feet ending in 10+" open hole								
Interval Costs								
	Interval 1	**Interval 2**	**Interval 3**	**Interval 4**	**Interval 5**	**Interval 6**	**Total**	**%**
Casing Set Point	1,250	5,000	10,000	15,000	19,000	21,000		
Interval length, ft	1,250	3,750	5,000	5,000	4,000	2,000	21,000	
Length of casing run, ft	1,250	5,000	5,200	5,200	19,000	-		
Activity								
Drilling time (cost in $)	$180,064	$307,133	$473,347	$627,516	$555,897	$301,111	$2,445,069	10.0%
Tripping time (cost in $)	$13,776	$25,745	$86,720	$145,437	$155,785	$265,580	$693,042	2.8%
Bits and tools	$149,500	$219,000	$407,000	$466,875	$617,760	$266,490	$2,126,625	8.7%
Directional Drilling	$3,960	$67,500	$198,767	$213,333	$193,846	$105,000	$782,406	3.2%
Casing (including time to run)	$976,550	$3,371,833	$2,431,593	$972,680	$1,706,420	$0	$9,459,077	38.7%
Cement (including time)	$928,540	$1,388,700	$974,010	$712,672	$1,691,431	$0	$5,695,353	23.3%
Drilling fluids (incl. air and cleaning equipment)	$26,333	$42,000	$115,500	$132,333	$93,846	$46,667	$456,679	1.9%
Trouble	$58,520	$194,830	$59,360	$32,680	$31,680	$63,360	$440,430	1.8%
End of interval (logging, testing, and wellhead)	$124,140	$298,103	$311,105	$601,576	$497,355	$521,487	$2,353,765	9.6%
Total interval costs	**$2,461,384**	**$5,914,845**	**$5,057,402**	**$3,905,101**	**$5,544,020**	**$1,569,694**	**$24,452,446**	100.0%
UpFront / Distributed Costs								
Rig mob and demob							$665,000	
Pre-spud engineering							$240,000	
Site prep, cellar, conductor							$154,500	
Contingency (10% of intangible drilling costs)							$1,499,337	
Total well cost							**$27,011,283**	
Analysis of Interval Costs								
Drilling Costs	$373,634	$661,378	$1,281,333	$1,585,494	$1,617,134	$984,848	$6,503,821	26.6%
Drilling $/ft of interval	$299	$176	$256	$317	$404	$492	$310	
Casing & Cement Costs	$1,905,090	$4,760,533	$3,405,603	$1,685,352	$3,397,851	$0	$15,154,430	62.0%
Casing $/ft of casing set	$1,524	$952	$655	$324	$236		$488	
Other Costs (not UpFront& Distrib)	$124,140	$298,103	$311,105	$601,576	$497,355	$521,487	$2,353,765	9.6%
Other Costs/foot	$99	$79	$62	$120	$124	$261	$112	
Total Cost per foot of Interval	$1,969	$1,577	$1,011	$781	$1,386	$785	$1,164	100.0%

Table 33: Interval Cost Estimate for 10 inch, 20,000 foot Stainless Steel Wells, SOPO 3

21,000 feet ending in 10+" open hole — CO2 Cases — Interval Costs	Interval 1	Interval 2	Interval 3	Interval 4	Interval 5	Interval 6	Total	%
Casing Set Point	1,250	5,000	10,000	15,000	19,000	21,000		
Interval length, ft	1,250	3,750	5,000	5,000	4,000	2,000	21,000	
Length of casing run, ft	1,250	5,000	5,200	5,200	19,000	-		
Activity								
Drilling time (cost in $)	$180,064	$307,133	$473,347	$627,516	$555,897	$301,111	$2,445,069	7.6%
Tripping time (cost in $)	$13,776	$25,745	$86,720	$145,437	$155,785	$265,580	$693,042	2.2%
Bits and tools	$149,500	$219,000	$407,000	$466,875	$617,760	$266,490	$2,126,625	6.6%
Directional Drilling	$3,960	$67,500	$198,767	$213,333	$193,846	$105,000	$782,406	2.4%
Casing (including time to run)	$976,550	$3,371,833	$2,431,593	$972,680	$6,825,680	$0	$14,578,337	45.5%
Cement (including time)	$928,540	$1,388,700	$974,010	$712,672	$3,382,862	$0	$7,386,784	23.1%
Drilling fluids (incl. air and cleaning equipment)	$26,333	$42,000	$115,500	$132,333	$93,846	$46,667	$456,679	1.4%
Trouble	$58,520	$194,830	$59,360	$32,680	$31,680	$63,360	$440,430	1.4%
End of interval (logging, testing, and wellhead)	$124,140	$298,103	$311,105	$601,576	$997,355	$771,487	$3,103,765	9.7%
Total interval costs	**$2,461,384**	**$5,914,845**	**$5,057,402**	**$3,905,101**	**$12,854,711**	**$1,819,694**	**$32,013,137**	100.0%
UpFront / Distributed Costs								
Rig mob and demob							$665,000	
Pre-spud engineering							$240,000	
Site prep, cellar, conductor							$154,500	
Contingency (10% of intangible drilling costs)							$1,499,337	
Total well cost							**$34,571,974**	
Analysis of Interval Costs								
Drilling Costs	$432,154	$856,208	$1,340,693	$1,618,174	$1,648,814	$1,048,208	$6,944,251	21.7%
Drilling $/ft of interval	$346	$228	$268	$324	$412	$524	$331	
Casing & Cement Costs	$1,905,090	$4,760,533	$3,405,603	$1,685,352	$10,208,542	$0	$21,965,121	68.6%
Casing $/ft of casing set	$1,524	$1,269	$681	$337	$2,552	$0	$1,046	
Other Costs (not UpFront& Distrib)	$124,140	$298,103	$311,105	$601,576	$997,355	$771,487	$3,103,765	9.7%
Other Costs/foot	$99	$79	$62	$120	$249	$386	$148	
Total Cost per foot of Interval	$1,969	$1,577	$1,011	$781	$3,214	$910	$1,524	100.0%

The effect of the cladding increases the well cost by 28%, from nominally $27M to $34M. In addition, the production wells will get dual completion, which is accounted for in WBS 2.

WBS - 3 Reservoir Filling

WBS 3 for the CO_2 EGS, includes the top side equipment, mostly associated with gas processing. Plasma Energy was responsible, with support from GEECO, for the design and selection of the gas processing and filling system. The WBS 3 spreadsheet provides the costing associated with the filling, top-off system, and as before the siphon starter motor. The WBS 3 cost for SOPO 3 is $124M.

Table 34: Summary Costs for WBS 3 - CO_2, SOPO 3

WBS	Cost	Item	Basis / Comment									
3.0	$124,898,656	CO2	Mega Ton Required to fill =			1.0	MT		Number of 25 MW Turbine Modules			
3.1	$42,000,000	Oxygen Plant (for filling system)	1000 TPD Praxair Quote						1			
3.2	$18,500,000	25 MW Gross Combustion System (for filling)	25 MW Turbines @ <$0.5M/MW, Simple Combustion Can									
		Net Power MW	12.75						Net Power Per Module Calculation			
		For 950 F @ 900 psig, Diluent Ratio, defined as the mass of water per mass of fuel and oxidant is =					1.4125		25	MW	(Gross)	
		Net Exhaust will be about 77% steam by mass.	Net Exhaust is 89% Steam by Volume.						10	MW	(ASU)	
		Initial Results (using Steam Only in the Steam Turbine, 89% Steam by volume will be close)							2	MW	(CO2 Compression,	
		Total Massflow =	70	lbm/sec					0.25	MW	(H2O Pumping)	
		Combustion Power (STP) =	450.2	MMBTU/HR								
		Methane Flow Rate =	5.8	lbm/sec		21551	BTU/lbm	(LHV)				
		Oxygen Flow Rate =	23.2	lbm/sec	1003	tons / day						
		Carbon Dioxide Generation Rate=	16.0	lbm/sec	689	tons / day		251634	tons / year		57451	lbm/hr
		Diluent Water Flow Rate =	41.0	lbm/sec	294.9	gpm		Diluent Pump Power =			229.4	hp
		Oxygen and Methane Compressed As Liquids (Part of Praxair System)										
3.3	$26,426,000	CO2 Top Off Modules (CCD System)	Generates 70 TPD CO2, At Pressure Per Diesel Set (2 is baseline at 140 TPD)									
		Details:										
		Genset	6,913,000	Cost of 1 32/40 Dual Fuel Engine & Generator plus Auxiliaries & Controls								
		VPSA, 100 Ton Per Day	3,900,000	926 kW								
		Top Off Power Level	6160	kWm = 100% rated load for one 16 cylinder, FM/MAN 32/40 engine								
		Generator Efficiency	0.97	5975	kW							
		Specific Fuel Consumption	6040	BTU/hp-hr @ 100% load								
		Fuel Price ($/mmBTU)	4.00	Current cost of natural gas								
		ORC (800 kW each)	2,400,000	22% cycle efficiency 750 F exhaust waste heat, 3.6 MW heat available to 120 F								
		Number of dual fuel engines	2	# engines @ 70 TPD required to make CO2								
		Hours of operation per year	8000	Assumes 97% availability or uptime per year + time for maintenance								
3.4	$2,000,000	Electric Blower to Start Thermal Siphon	1000 hp multi-stage compressor, electric drive (Solar Turbines)									
3.5	$1,790,000	Diesel Genset for Backup Power	ROM									
		Details (for backup genset as well)										
			1,790,000	Cost of 1 OP Dual Fuel Engine & Generator plus Auxiliaries & Controls								
		Power Level	1506	kWe = 100% rated load at the generator output for 1x6 cylinder OP engine								
		Specific Fuel Consumption	6400	BTU/hp-hr @ 100% load								
		Fuel Price ($/mmBTU)	4	Current cost of natural gas								
		Number of dual fuel engines (for CO2)	0	Assumes 32/40 for CO2 Production								
			1	Backup Genset								
		Hours of operation per year	8000	Assumes 97% availability or uptime per year + time for maintenance								
3.6	$400,000	Filtration	ROM									
3.7	$90,000	Freeze Protection	ROM									
3.8	$1,250,000	CO2 Compression (Brute Force, 5 Stage Compressor)	625,000	69 TPD	400 hp (electric)							
		Number of Compression Modules	2									
3.9		YEARLY COST ADJUSTMENTS (NOT Reflected in Above Capital Cost Total, Imported to Master Sheet)										
	$3,511,009	NG Fuel Costs (Not Summed Above)										
	$1,076,512	Engines Maintenance Costs (Not Summed Above)					0.01	Based on $.01/kW-hr. OP engine: $.01 x (1506x3) x 8000.				
		Generated Power (diesels)	13,456.4	kW								
		ORC	1600	kW								
		Consumed Power										
		CO2 Compressors	663	kW								
		Top Off O2 Plant	1852	kW								
		Net Power to Market (Top Off System)	12,541	kW								
	$10,986,169	Value of Electricity (for reference per year @ $100)										
3.10	$30,250,000	ONE TIME COST ADJUSTMENTS SAVINGS (Reflected in Above Capital Cost Total)										
	$21,000,000	Sale (or Reuse on Other Project) Price of Oxygen Plant (value remaining after # days below)										
	$9,250,000	Sale (or Reuse on Other Project) Balance of Filling System (value remaining after # days below)										
3.11	$62,692,656	ONE TIME COST ADJUSTMENTS COSTS (Reflected in Above Capital Cost Total)										
	1451	Calculated Duration of Filling System Operation (day:	3.97	years								
		(4 years or less is desired, duration of drilling program is 4 years or more)										
	$62,692,656	Filling System Fuel Costs (total for # days above)										

The major functions of the the top side equipment are:

- Reservoir Filling with CO_2 Prior to Operation
- Reservoir Top Off with CO_2 During Operation
- System Start and Backup Power
- Gas Clean Up (Water / Solids Removal)

These are listed in nominally the order of cost, from highest to lowest. Since the production fluid is a gas, we believe that solids separation (and later in the process liquid separation), except for the finest of particles, will occur in the production well itself. A moisture separator would be used to take out significant liquid fractions (which would exist in the filling and beginning of operational phases) prior to the turbine. The turbo machinery (discussed already in SOPO 2.0, WBS 4) is built of corrosion resistant alloys, so the real need is just enough water removal to prevent liquid (acid) condensation / droplets in the injection wells.

Reservoir filling and reservoir top off will be in a contest for the most significant cost in this WBS. For SOPO 2.0, with the wells at 30,000 ft and the cycle efficiency at 22%, we had 0.73 Mega Tons of CO_2 to fill, at \$175M. We then had a yearly cost for top off, also based on purchased CO_2, of \$7.3M. Over 309 years, this would actually total over \$200M, but in net present value terms, the filling cost is the greatest burden. The top off rate is one of the greatest unknowns, and our assumptions were based on a fairly tight (deep) reservoir, and high cycle efficiency. The actual top off rate used was around 66 tons / day, or 24,000 tons per year.

The change in cycle efficiency for the 20,000 ft CO_2 EGS vs. 30,000 ft CO_2 EGS is from 15% to 22%. The reservoir volume required scales inversely with this ratio and increases from 0.73 MT to 1.0 MT. Though one could argue for a smaller than 46% increase in top off rate, since the surface area does not increase at the same rate as the volume, to be conservative we more than doubled the top off rate, from 66 tons per day to nominally 140 tons per day.

While the uncertainty in these numbers in WBS 3 is alarming, it is less so for SOPO 3 than SOPO 2. In the previous section (SOPO 2.0), if we were off by a factor of two or three in either the estimate of the porosity of the reservoir or the leakage rate, we would have the same factor of two or three change in WBS cost -- generating significant investment risk for a CO_2 EGS. In this section, SOPO 3.0, we are using unique technology to “manufacture” the CO_2 on site at pressure, and at profit. If we are off on the reservoir characteristics, it becomes an operational issue (e.g. duty cycle for the top off system) or development timeline issue (e.g. it takes 3 years vs. 2 years to fill the reservoir). The uncertainty in the geology and EGS behavior is the same, but due to the approach, the risk for the investor is markedly lowered, perhaps enabling CO_2 EGS, at least somewhere.

The filling system volumes that are required (2.5 MT over the life of the project) exceed what is reasonable to expect (at a TRL of 6) from “green” sources of CO_2, with the possible exception of ethanol production. As a result, we are looking at CO_2 from a combustion process, which generates power to offset the cost of fuel. There are three general approaches considered to carbon capture they are: pre-combustion capture (some variant of reforming) as one might see in an IGCC or fuel cell system, post-combustion capture (amine towers) as one might see on a conventional power plant, and oxy-combustion based capture. The latter, oxy-combustion, is the approach selected for this project, and is also the approach in the large DOE Clean Coal Project: FutureGen2.

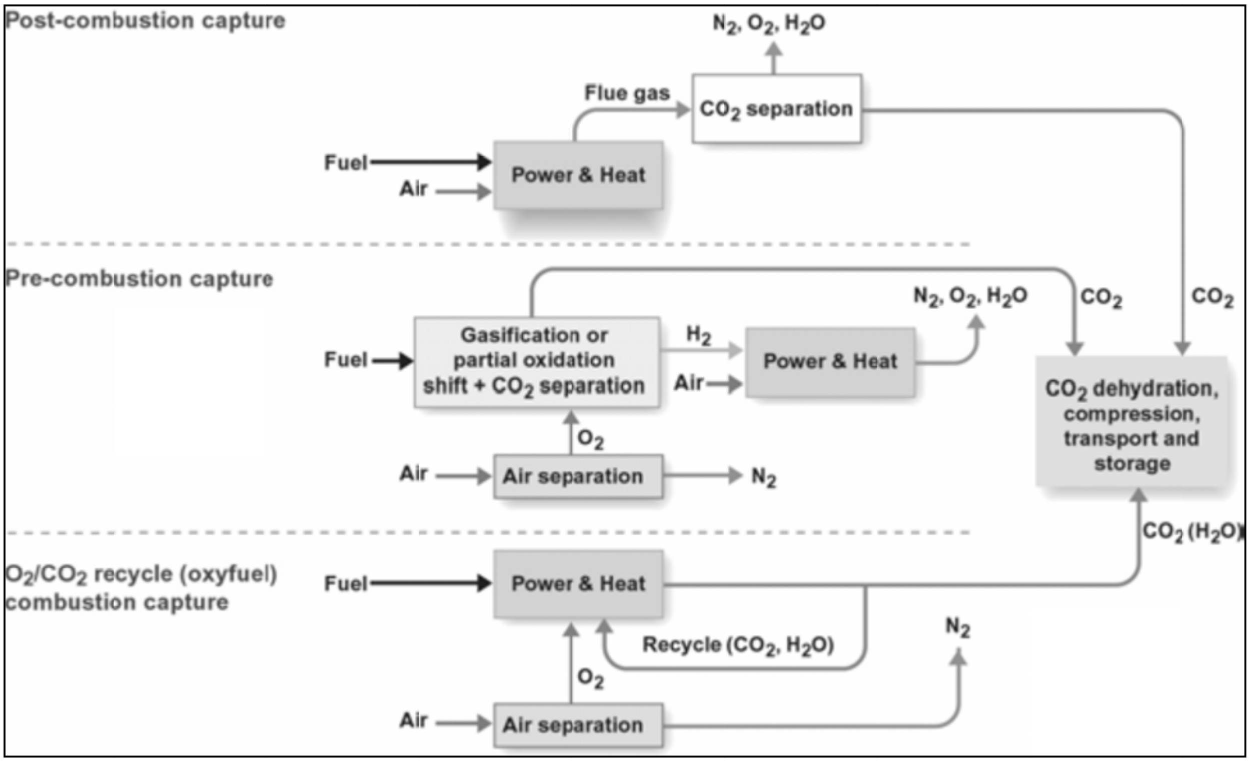


Figure 19: The Three Basic Concepts for Power Generation with CO_2 Capture.

Vattenfall Utveckling AB.

Efficient (cost effective) generation of CO_2 generally requires the lowest cost fuel, with the highest ratio of Carbon to Hydrogen. Coal and Pet Coke would be very good candidates, and the Plasma Oxy-Combustion technique actually also includes the ability to capture the fuel borne sulfur (as a solid sulfate), an additional benefit.

Oxygen combustion, with recirculation of CO_2 (or water) as the diluent, is summarized in the simple block diagram.

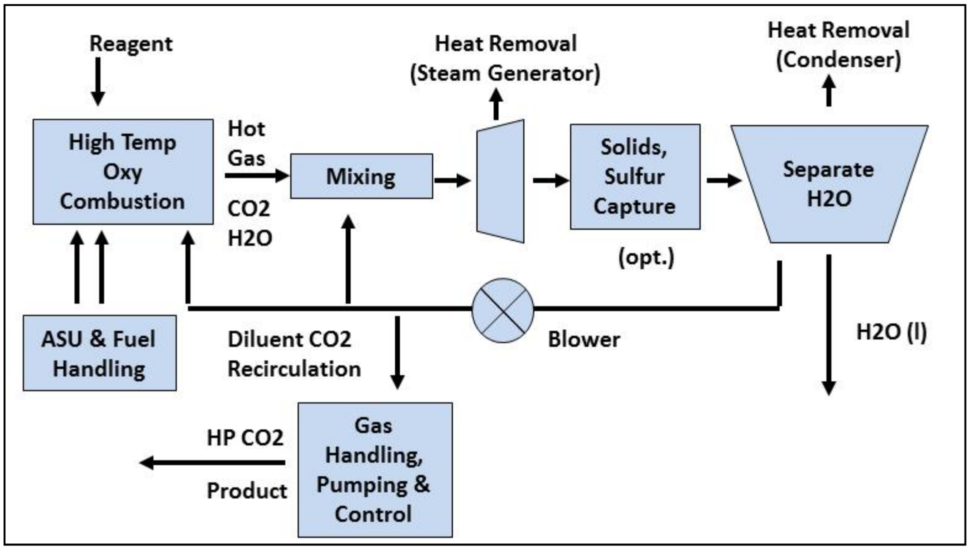


Figure 20: Block Diagram of Oxygen Combustion for CO_2 Generation

We started with the idea of a hybrid system, perhaps making 50 MW, the amount of power required via some future PPA, with a greenfield oxy fired approach to a Rankine cycle power plant. Potentially the nearby Mt. Tom coal fired power plant could be replaced or upgraded (100+ MW) and that this total power level could be produced by the new 50 MW system, plus the geothermal system.

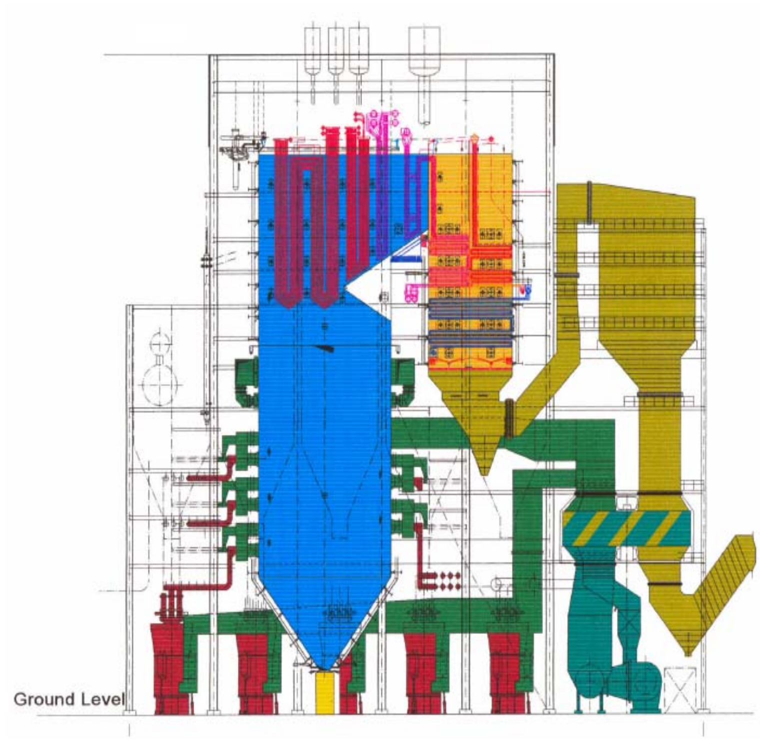


Figure 21: Coal Fired Power Plant Schematic

This approach was quickly rejected. Though it was possible to make a small conventional coal / pet coke fired Rankine cycle plant, at 50 MW this would still be a ~$350M undertaking. Plants of this type are quite complex and are simply not cost effective in this size range. It also did not make sense to build a 30+ year asset for a 2-3 year problem (reservoir filling).

At the same time the team was discussing this, there was much concern building over a new coal fired plant of any type in Massachusetts. This represented a significant permitting risk, and is sort of the opposite of what we are ultimately trying to achieve with geothermal (renewable) power. As a result, the decision was made to not only abandon the conventional plant, but to abandon solid fuels as a source of CO_2.

Pipeline natural gas is available in the area, and is in fact already on Westover AFB. Given the price of fuel per MMBTU, it was easy to choose natural gas over ULSD. The main metric for the filling system became Tons CO_2/day over capital cost, not cycle efficiency, though it was still a goal to make at least enough power to pay for the fuel costs.

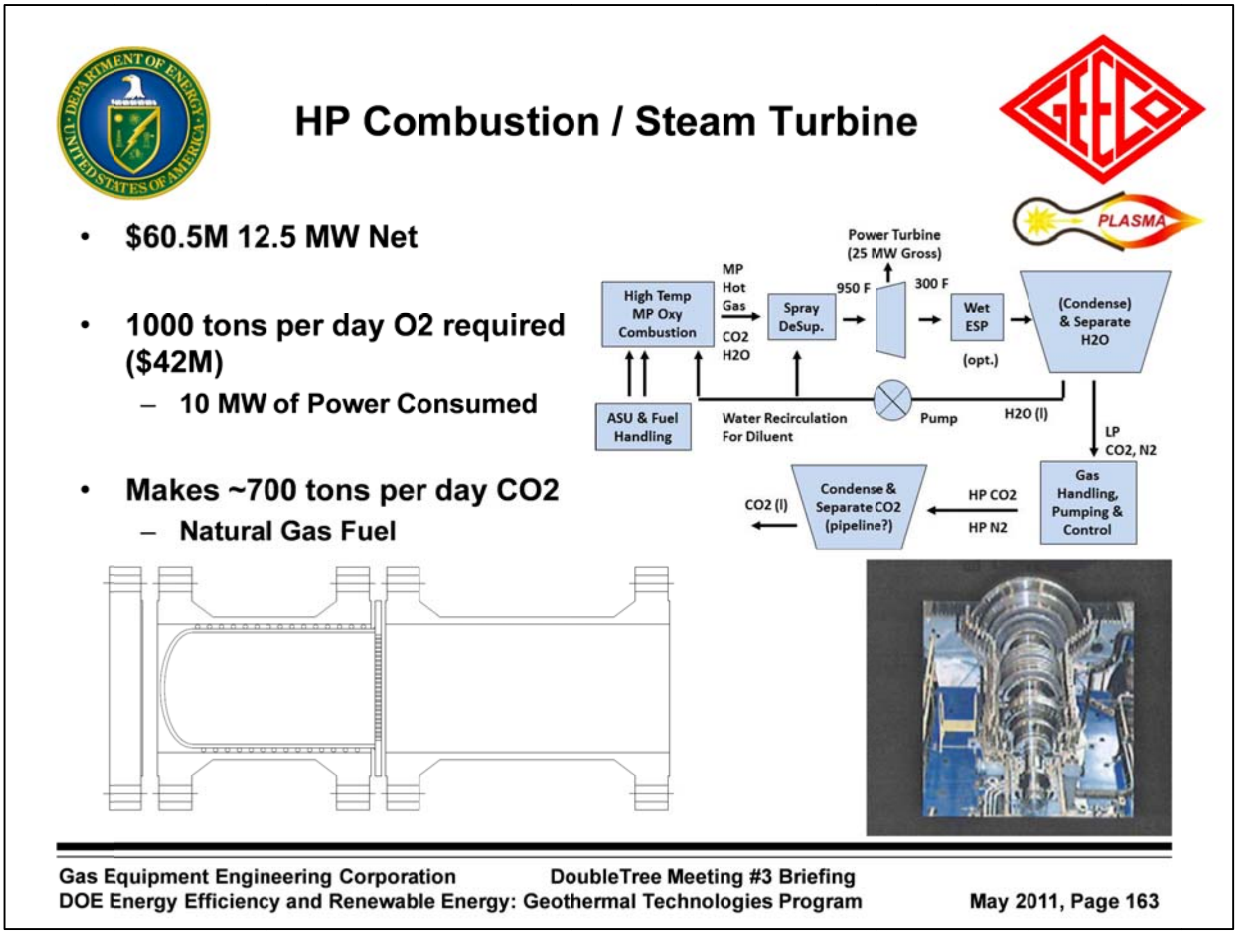


Figure 22: Combustion Turbine for CO_2 Generation

The decision was made to modify the combustor Rankine steam cycle approach to be a combustion turbine system, with water recirculation, not CO_2 recirculation. An unmodified Dresser Rand Model 1 turbine, rated for 25 MW was used, fed by a simple oxygen-natural gas pipe combustor with water diluent. The Model 1 is rated for 950 deg F steam. Cycle efficiency will be low, around 20%, given that there is no recuperation and that backpressure is slightly above atmospheric pressure, vs. the typical vacuum of a steam plant. Still, the 1000 tons of O2 will be matched by 250 tons / day of Natural Gas, and at $4/MMBTU, this is around a $1750/hr fuel burn rate. The power produced (net after the associated Air Separation Unit and compressor power) is offsetting the power that would otherwise be required on a retail basis to operate construction / drilling equipment, and at $160/MW-Hr, the 12.5 MW net produced as a value of $2000/hr. In fact, the break-even point is at $140/MW-Hr, and the 2008 retail price in this area was $170/MW-hr.

The top-off system has a different set of metrics. While capital cost is important, this system can be amortized over the life of the geothermal power plant. The metric of import is the effective price (cost) or profit per ton of CO_2 produced. Since this system would operate near continuously for 30 years, approaches with long component life and very low maintenance were also required.

The combination of these factors led us to the medium speed "diesel" engine, modified to run on natural gas (actually dual fuel, any combination of diesel / natural gas, with at least 1% diesel used as a pilot to ignite the natural gas), and modified for the semi-closed cycle.

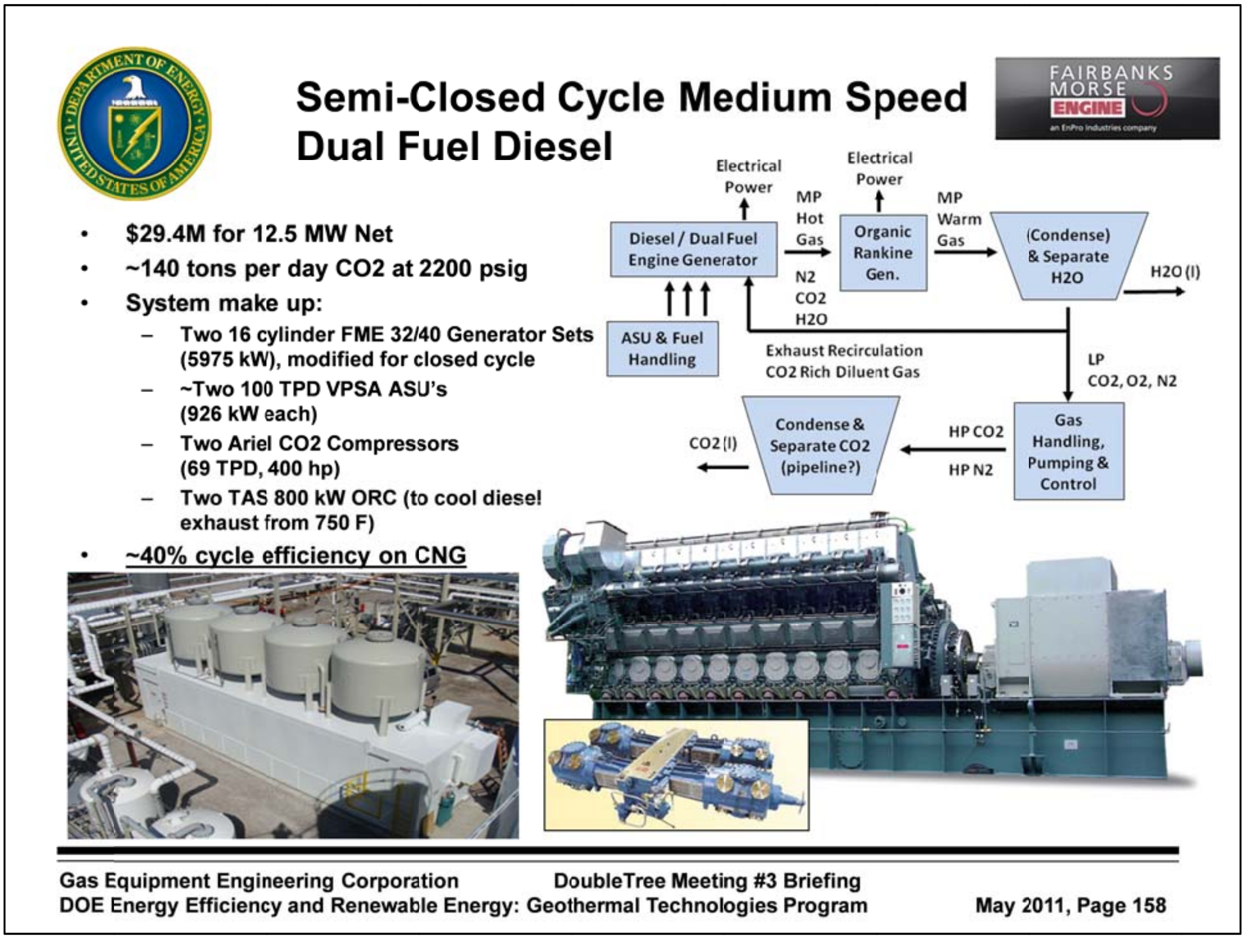


Figure 23: Diesel Generators for CO_2 Generation

Instead of cryogenic air separation, which is required to be cost effective at the larger scale of the filling system, a Vacuum Pressure Swing Adsorption (VPSA) approach is used. An Organic Rankine Cycle (ORC) is used for heat recovery off the diesel exhaust, to cool the exhaust as required for the CO_2 / Water separation, and also to offset the VPSA power. The net result is that the very efficient large medium speed diesel, which starts at ~42% on air, is still near 40% efficient in this application.

As noted above, the WBS 3 cost as we move from SOPO 2.0 to SOPO 3.0 has reduced from $187M to $124M, which by itself would be a good improvement as a result of technology. More importantly, the SOPO 3.0 WBS 3 approach now provides significant yearly revenue from the top-off system (about 20% of total revenue), and the filling system cost is also offset by one time power sales revenue and subsequent sale of the used, but still valuable filling system components.

WBS 4-6 - Energy Conversion and Power Distribution Equipment

There is no change in the WBS 4-6 area from SOPO 2 to SOPO 3. The benefits (reduced capital cost, significantly higher efficiency) of direct turbo expander power generation still apply. The costs for WBS 4 -6 total $91M and summarized below.

Table 35: Summary Costs for WBS 4, 5 and 6 Power Generation, Transmission and Distribution, SOPO 3

WBS	Capital Cost (50 MW)	WBS Element
4.0	**$70,000,000**	Power generation
5.0	**$3,500,000**	Integration / Distribution (local)
6.0	**$18,000,000**	Integration / Distribution (grid)
Total	**$91,500,000**	

WBS 7-10 - Project Management, Permitting, Operation

Changes to WBS 7 to 10 between SOPO 2 and SOPO 3 are mostly associated with the change in land area, structures to support the top-off system, and additional permitting associated with the top-off and filling systems.

A comparison of the overall SOPO 2 and SOPO 3 costs in the WBS 7-10 area is provided below.

Table 36: Comparison of SOPO 2 and SOPO 3 Costs for WBS 7, 8, 9, and 10

WBS	SOPO 2 Capital Cost	SOPO 3 Capital Cost	WBS Element
7.0	**$8,005,000**	**$8,155,000**	**Topside Structures**
8.0	**$6,985,000**	**$9,535,000**	**Land Acquisition / Land Use**
9.0	**$4,530,000**	**$5,030,000**	**Permits / Approvals**
10.0	**$10,907,917**	**$11,244,167**	**Project Management**
Total	**$30,427,917**	**$33,964,167**	

The net result is that costs have increased slightly, from $30M to nearly $40M, from SOPO 2 to SOPO 3. The cost changes in WBS 8 are due to topside structure changes (less CO_2 storage / receiving, more diesels), change in land area required (25 wells vs. 18 wells), changes in permits (additional for filling / top-off), and a change in project development timeline (more wells to drill, plus filling time).

WBS 7 – Top of Well Sites and Facilities

WBS 7 costs of $8.2M are summarized in the table below.

Table 37: Summary Costs for WBS 7 - Top of Well Site and Facilities, SOPO 3

WBS	Costs	
7.0	$8,155,000	**Top of well sites and facilities to house surface elements of 50 MW CO2 EGS**
7.1		**Design**
7.1.1	$350,000	Engineering: Survey of property, soil borings, design of topography, stormwater management, standard building utility connections
		Cost is largely dependent on size and number of structures and terrain
7.1.2	$30,000	Design of foundations for external equipment
		Cost will vary depending on number of external equipment pieces and repetitive design
7.1.3	$50,000	Engineering for construction of CO2 storage containment: Civil, Structural and Fire Protection.
7.2		**Construction**
7.2.1	$4,000,000	Major Buildings
		This estimate provides for a building of approxiamtely 32,000 square feet along with essential aspects of insulation, HVAC, electrical, plumbing, control room, office space, bathrooms, and security.
		The weight of building will be substantial with interior components. The foundation cost is largely variable based on soil stability present on the site and weight of the mechanical components chosen for the project.
7.2.2	$400,000	Construction of Concrete Pads / Foundations for External Equipment
		Place holder: Rough Estimate. Need to research: size and number of pads/foundations. All are currently unknown. Does not include pile driving for weak soil stability.
7.2.3	$400,000	External Equipment Shelters
		Due to the design of a network of wells, the potential for up to 12 equipment shelters of ranging sizes may be necessary during winter conditions dependant on the efficiency of the layout of the well heads, piping network and pump components.
7.2.4	$825,000	Earthwork for stormwater, utilities and conduit trenches between main building and well heads; exclusive of building and foundation construction
7.2.5	$100,000	Construction of CO2 storage foundations, piping and associated infrastructure
7.2.6	$2,000,000	Installation of manufactured CO2 and O2 containment tanks or construction of a custom storage facility

WBS 8 – Land Acquisition and/or Land Use with Royalty Agreements

WBS 8 costing, for the 50 MW SOPO 3 CO_2 EGS, totaling $9.5M, is provided below.

Table 38: Summary Costs for WBS 8 - Land Acquisition, SOPO 3

WBS	Costs	
8.0	$9,535,000	**Land acquisition and / or land use w/ royalty agreements**
8.1		**Primary Site Acquisition**
8.1.1	$100,000	Consulting Costs for property locating and feasibility studies
8.1.2	$9,250,000	Vary by size of facility (acres) and value of land; Assume average cost
		@ $10,000 per acre for 2,000 acres = **$20,00,000**
		@ $5,000 per acre for 750 acres = **$3,750,000**
8.1.3	$185,000	Closing Costs (2% ±)

WBS 9 - Federal, State, Local and Private (Stakeholders) Permits, Approvals, and Incentives

WBS 9 costing, higher vs. SOPO 1 for the same reasons as SOPO 2, plus the additional issues of SOPO 3.0, is provided below. The best estimate of total cost for WBS 9 is $5M.

Table 39: Summary of Costs for WBS 9 - Federal, State and Local Permits, SOPO 3

WBS	Cost	
9.0	**$5,030,000**	**Federal, state local and private (stakeholders) permits, approvals incentives leading to and enabling construction and operation of CO2 EGS**
9.1		**Consulting efforts toward receiving Permit and Approvals**
9.1.1	$750,000	Research and Planning of approval process, coordination with project team, permit expediting
9.1.2	$300,000	Stakeholder and Regulatory: Assessment, design of strategy, informational meetings, media and communications plan
9.1.3	$200,000	Contingency for Education/Outreach with local and state officials (including fees for agency expert consultation)
9.2		**Permit and License Fees**
9.2.1	$50,000	Building Permit Fee (Estimate based on City of Chicopee fee of $0.60/SF plus specific fees)
		Maximum Building Permit Fee is based on a cost of $7 per $1,000 of building code specific construction cost of surface building construction only.
		Minimum Building Permit Fee is based on the City of Chicopee building permit cost structure ($0.50/sf general permit cost, $0.10/sf electrical fee, plus others
9.2.2	$30,000	Other Permit Fees (Rough Estimate)
9.2.3	$900,000	Interconnection with Electric Grid (Fees and Two Studies)
9.2.4		GHG Reporting Costs (natural gas and geothermal)
9.3	$800,000	**Mitigation Requirements**
		To be further determined through reviewing agencies, community groups and abutters
9.4	$2,000,000	**Contingency for appeals and other stakeholder intervention**

WBS 10 – Project Management

WBS 10 project management costs totaling $11.2M are very similar in format to those of SOPO 1 and 2, and scaled based on the size of the project (reduced drilling time / reduced construction time) and are provided in the table below.

Table 40: Summary Costs for WBS 10 - Project Management, SOPO 3

WBS	COST	PROJECT MANAGEMENT							
10.0	**$ 11,244**	Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**
10.1	**$ 267**	**PLANNING & SCHEDULING**	40	40	40	40	40	40	27
10.2	**$ 107**	**DOCUMENT CONTROL & DESIGN**	40	20	10	10	10	10	7
10.3	**$ 93**	**QUALITY ASSURANCE**	-	-	20	20	20	20	13
10.4	**$ 3,850**	**PROCUREMENT & FIELD CONTRACTING**	300	300	600	750	750	750	400
10.5	**$ 2,400**	**CONSTRUCTION MANAGEMENT**	-	300	450	450	450	450	300
10.6	**$ 90**	**MANAGEMENT INFORMATION SYSTEM**	30	10	10	10	10	10	10
10.7	**$ 63**	**INSPECTION & TESTING**	-	-	13	13	13	13	13
10.8	**$ 4,375**	**INSURANCE, WORKPLACE SAFETY**	-	-	875	875	875	875	875
		Total:	$ 410	$ 670	$ 2,018	$ 2,168	$ 2,168	$ 2,168	$ 1,644

Notes:

1. Reservoir development is estimated at 4 years and 6 months. (Provided by Impact Technologies).

SOPO 3 50 MW CO_2 EGS Cost Summary Results

The capital cost for all the items associated with the construction of the 50 MW EGS system are rolled up into a higher level spreadsheet, and the levelized cost of electricity is calculated. Using the levelized electricity rate, the profit or loss of the proposed venture is calculated.

The capital costs for the 50 MW net CO_2 EGS, with technology, is summarized in the Table below.

Table 41: Summary Costs for WBS 1-10 –

50 MW CO_2 EGS With Technology Impacts, SOPO 3

WBS	Capital Cost	WBS Element
	50 MW Net	
1.0	$3,710,000	Resource ID / Analysis
2.0	$861,853,138	Reservoir Development
3.0	$124,898,656	Fluid Management & CO2 (filling)
4.0	$70,000,000	Power generation
5.0	$3,500,000	Integration / Distribution (local)
6.0	$18,000,000	Integration / Distribution (grid)
7.0	$8,005,000	Topside Structures
8.0	$6,985,000	Land Acquisition / Land Use
9.0	$4,530,000	Permits / Approvals
10.0	$10,907,917	Project Management
Total	$1,112,389,711	

As can be seen, the capital cost for the Project is much lower than for SOPO 2. The total cost is $1.1B, about $300M less than the SOPO 2 CO_2 EGS cost of $1.4B. Most of the savings is in the reservoir development area, due to a change in casing material cost.

The SOP0 3 summary spreadsheet for the 50 MW geothermal system with drilling technology and CO_2 generation technology is provided below:

Table 42: Summary Spreadsheet for 50 MW CO_2 EGS with Technology Impacts, SOPO 3

Parameters:	CO2 EGS		Comment	
Geothermal Power (Net)	50	MW	Geothermal Net Power	
Total Net Power	63	MW	Yearly Total (Not Including Filling)	
CO2 System Net Power (extra to be sold)	13	MW	(from WBS 3)	
Cost of Electricity (retail)	$167	$/MW-hr	(US DOE EIS 2008 MA)	
Cost of Electricity (wholesale)	$81	$/MW-hr	(ISO NE 2008 Hub Price)	
MA Renewable Market Class 1 RPS	$13	$/MW-hr		
Capital Cost	$1,112,389,711	(roll up)	(from capital sheet)	
Retail / Wholesale Split Filling System (default 100% retail)		100.0%	Retail %	
One Time Power Generated (filling system)	443858	MW-hr	(from WBS 3)	
Capital Cost Adjustment, One Time Power	$74,124,324	Filling Sys.	(Retail Portion)	
Capital Cost Adjustment, One Time Power	$0	Filling Sys.	(Wholesale Portion)	
Adjusted Capital Cost (Minus Filling Income)	$1,038,265,387			
Cost of Capital	7.0%	(high)	(variable)	
	20	(30 year default)		
Annual Capital Cost	$98,004,908		(calculation)	
O&M Cost	$10	$/MW-hr	2007 GRC Presentation	
Availability	99.5%	(uptime)	(guess)	
Cost Item	$			
Annual Capital Cost	$98,004,908		Escalation Rate (%/year)	
O&M Cost	$4,358,100		2.0%	
O&M Cost Engines	$1,076,512			
Purchased Costs (Fuel / CO2)	$3,511,009		1.811361584	(30 year)
Total Annual Cost	$106,950,529			
	Revenue (1st Full Year)		Revenue (30th Year)	
		Percent	Impact of Escalation in Electric Costs	
Offset of Retail Electricity	$45,517,719	50.0%	$82,449,047	
Wholesale Electricity	$22,077,456	50.0%	$39,990,257	
MA Renewable Market Class 1 RPS	$7,086,591		$7,086,591	
Renewable Investment Tax Credit	$10,902,448		(Zero After 10 Years)	
Total Revenue	$85,584,214		$129,525,895	
Profit / Loss	($21,366,315)		$22,575,366	

As can be seen, unfortunately, even with technology this project would likely still lose money with the baseline financial assumptions. The yearly loss decreases from $80M from SOPO 2 to $21M, and in theory would make money in the out years.

A change in the power selling ratio from 50%/50% retail / wholesale to 100% offset of retail does allow this project to make money, in Massachusetts. It is important to note that only the use of CO_2, and the use of drilling and CO_2 generation technology, allow for the potential of a cost effective (positive revenue) EGS project in Massachusetts. The results, with no change in the financial assumptions, but with 100% retail sales, are provided below.

Table 43 - Summary Spreadsheet for 50 MW CO_2 EGS with Technology Impacts, SOPO 3, 100% Retail Electricity Sales

Parameters:	CO2 EGS		Comment	
Geothermal Power (Net)	50	MW	Geothermal Net Power	
Total Net Power	63	MW	Yearly Total (Not Including Filling)	
CO2 System Net Power (extra to be sold)	13	MW	(from WBS 3)	
Cost of Electricity (retail)	$167	$/MW-hr	(US DOE EIS 2008 MA)	
Cost of Electricity (wholesale)	$81	$/MW-hr	(ISO NE 2008 Hub Price)	
MA Renewable Market Class 1 RPS	$13	$/MW-hr		
Capital Cost	$1,112,389,711	(roll up)	(from capital sheet)	
Retail / Wholesale Split Filling System (default 100% retail)		100.0%	Retail %	
One Time Power Generated (filling system)	443858	MW-hr	(from WBS 3)	
Capital Cost Adjustment, One Time Power	$74,124,324	Filling Sys.	(Retail Portion)	
Capital Cost Adjustment, One Time Power	$0	Filling Sys.	(Wholesale Portion)	
Adjusted Capital Cost (Minus Filling Income)	$1,038,265,387			
Cost of Capital	7.0%	(high)	(variable)	
	20	(30 year default)		
Annual Capital Cost	$98,004,908		(calculation)	
O&M Cost	$10	$/MW-hr	2007 GRC Presentation	
Availability	99.5%	(uptime)	(guess)	
Cost Item	$			
Annual Capital Cost	$98,004,908		Escalation Rate (%/year)	
O&M Cost	$4,358,100		2.0%	
O&M Cost Engines	$1,076,512			
Purchased Costs (Fuel / CO2)	$3,511,009		1.811361584	(30 year)
Total Annual Cost	$106,950,529			
	Revenue (1st Full Year)		Revenue (30th Year)	
		Percent	Impact of Escalation in Electric Costs	
Offset of Retail Electricity	$91,035,438	100.0%	$164,898,095	
Wholesale Electricity	$0	0.0%	$0	
MA Renewable Market Class 1 RPS	$7,086,591		$7,086,591	
Renewable Investment Tax Credit	$10,902,448		(Zero After 10 Years)	
Total Revenue	$109,024,476		$171,984,686	
Profit / Loss	$2,073,948		$65,034,157	

The final step, SOPO 4, is to assess the impact of location.

SOPO 4 Assessment of 50 MW System (Water or CO_2) at other Locations

The final objective, after evaluation of how CO_2 impacts the cost of an EGS system, and how drilling technology and CO_2 generation technology impact the cost of an EGS system, is to evaluate location. This will not be done to the same detail (each WBS item) as for the previous sections, but the spreadsheets for all items SOPO 1-4 and WBS1-10, with summary sheets are provided as an Appendix.

Geothermal energy is like real estate: "location, location, location". For the purpose of this effort, having studied the North East, we wanted to address performance in the Southern and Western portions of the country.

Given the fact that a military base was our virtual "host" site for this cost analysis effort, we continued to evaluate Government sites. As a result, we choose for final evaluation:

1. Ft. Bliss, El Paso, TX
2. Mountain Home AFB, Mountain Home, ID
3. Naval Air Weapons Station, China Lake, CA

Shortly after making this change we learned of potential difficulties with drilling at Mountain Home, though we kept it as a site, and we also learned that China Lake might have naturally occurring CO_2 in spots. So in the end, we did the analysis for two versions of China Lake, one exploiting the naturally occurring CO_2 (now vented to the atmosphere in existing geothermal power plants on site), and one that required manufactured CO_2.

We also learned that Ft. Bliss would be more suitable as a water EGS than a CO_2 EGS. There is a natural aquifer which would tend to consume (sequester) CO_2, which is good if that is your objective, but bad if you are trying to make geothermal power, since it will drastically increase the amount of top off CO_2 required, even assuming such a reservoir could be filled in the first place.

In the end, four sites with a good cross section of electric rates, location, rock type and EGS type were selected to explore how the costs established for Westover AFB in Massachusetts would change at other locations.

The four sites are:

1. Ft. Bliss, Water EGS
2. Mountain Home, CO_2 EGS, with drilling technology and CO_2 generation technology
3. China Lake, with drilling technology and naturally occurring CO_2
4. China Lake, with drilling technology and CO_2 generation technology

FUGRO was tasked to gather available information on these sites to support our cost modeling efforts – early into that effort it was clear that a wide range of gradients existed in the broad areas (large bases) identified above. A detailed survey to optimize the location would of course be part of an actual project, but for the effort herein it was deemed best to select thermal gradients that were consistent with observations, and that would give us a broad range of conditions to model. A chart summarizing the range of conditions, and the gradients selected for analysis is provided below:

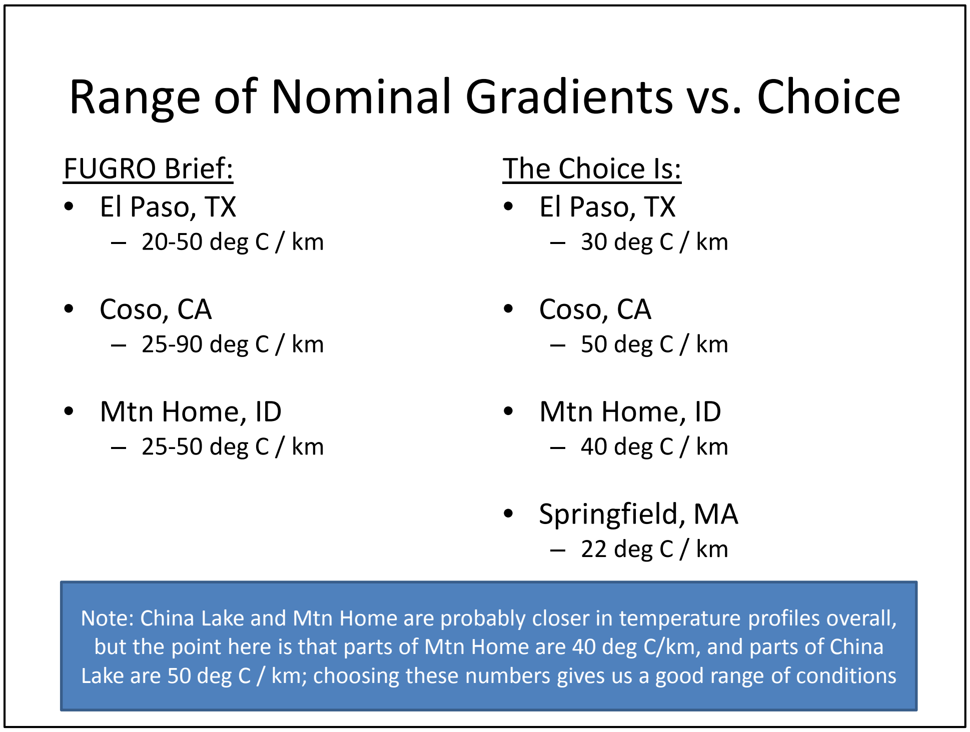


Figure 24: Temperature Gradients for El Paso, TX; Coso, CA; and Mountain Home, ID

It is not surprising that these other locations have higher gradients than western Massachusetts, and evaluating performance at these four locations with these assumptions basically gives us a nice range of gradients.

The slide below summarizes the range of gradients and geology types for the locations chosen. Additional details are provided in the sections that follow.

SOPO 4: Summary of Conditions

Site	Bedrock Type / Depth	Drilling Conditions	Geothermal Gradient	Seismic Hazards	Additional Cost for Site Specific Characterization
Fort Bliss, TX	Paleozoic Carbonates <0.5 km	Good, shallow fractured bedrock with alluvial overburden	20° C to 50° C per kilometer	Moderate to Low	Low, potential for karst features and dissolution
Mountain Home AFB, ID	Silisic Volcanic (Rhyolite) >4 km	Poor, layered basalt flows, unknown fracture density at depth	25° C to 50° C per kilometer	Low	Moderate >$250k for seismic study
Coso, CA	<0.5 km to variable	Good but bedrock conditions unknown at depth	25° C to 906° C per kilometer	Moderate	Low to moderate given pre-existing research studies

Figure 25: Summary of Geologic Conditions for Fort Bliss, TX; Mountain Home AFB, ID; and Coso, CA

Drilling depths were selected based on the gradients to generate approximately the same temperature as for the other locations, but were modified for other factors. A chart that summarizes the surface temperature, assumed gradients, and resulting temperature profile is provided below. The colors on this chart show the selected depths for drilling modeled, e.g. 20,000 and 30,000 ft in Massachusetts, and 10,000 to 14,000 ft at the other locations.

Table 44: EGS Temperature Profiles Comparison – Westover, MA; Ft. Bliss, TX; Mountain Home, ID; and China Lake, CA

		Westover		Ft. Bliss		Mtn Home		China Lake	
Surface Avg		dec C	deg F	dec C	deg F	dec C	deg F	dec C	deg F
		19	66	25	77	18	64	27	81
Inj Temp (H2O)			110		125		N/A		N/A
Inj Temp (CO2)			80		N/A		80		100
Avg. CO2 Backpressure (psia)			1000		N/A		1000		1500
Gradient	deg C /km	22		30		40		50	
	deg F / 100'		1.21		1.65		2.19		2.74
Note				(Same Temp as MA)		(Basement 4 km)		(Pressure Driven)	
Depth (ft)	Depth (km)	dec C	deg F	dec C	deg F	dec C	deg F	dec C	deg F
0	0	19	66	25	77	18	64	27	81
1000	0.30	26	78	34	93	30	86	42	108
2000	0.61	32	90	43	110	42	108	58	136
3000	0.91	39	102	52	126	54	130	73	163
4000	1.22	46	114	62	143	67	152	88	191
5000	1.52	52	126	71	159	79	174	103	218
6000	1.83	59	138	80	176	91	196	119	246
7000	2.13	66	150	89	192	103	218	134	273
8000	2.44	73	163	98	209	115	240	149	300
9000	2.74	79	175	107	225	128	262	164	328
10000	3.05	86	187	116	242	140	283	180	355
11000	3.35	93	199	126	258	152	305	195	383
12000	3.66	99	211	135	275	164	327	210	410
13000	3.96	106	223	144	291	176	349	225	438
14000	4.27	113	235	153	307	188	371	241	465
15000	4.57	119	247	162	324	201	393	256	492
16000	4.88	126	259	171	340	213	415	271	520
17000	5.18	133	271	180	357	225	437	286	547
18000	5.49	140	283	190	373	237	459	302	575
19000	5.79	146	295	199	390	249	481	317	602
20000	6.10	153	307	208	406	262	503	332	630
21000	6.40	160	319	217	423	274	525	347	657
22000	6.71	166	332	226	439	286	547	363	685
23000	7.01	173	344	235	456	298	569	378	712
24000	7.32	180	356	244	472	310	591	393	739
25000	7.62	187	368	254	488	323	613	408	767
26000	7.92	193	380	263	505	335	635	423	794
27000	8.23	200	392	272	521	347	657	439	822
28000	8.53	207	404	281	538	359	678	454	849
29000	8.84	213	416	290	554	371	700	469	877
30000	9.14	220	428	299	571	384	722	484	904

While it would have been ideal to select depths with 308 deg F nominal for all cases, we did not do this for the following reasons:

- At Ft. Bliss we chose the exact depth to match the Westover AFB Water EGS temperature so that we could use the same number of wells and overall design / spacing. This resulted in a depth of 14,000 ft.
- At Mountain Home we went as shallow as possible to avoid the basalt, which is hard drilling. This resulted in a depth of 10,000 ft.
- At China Lake, a depth of 8,000 would be possible based on temperature, but this depth did not generate a great enough thermal siphon to drive a turbine for a CO_2 EGS. As a result, we choose 12,000 ft, mostly since it was between the other two cases for SOPO 4.

Ft. Bliss Water EGS

An overview of the specifics for the Ft. Bliss location are provided in the following figures.

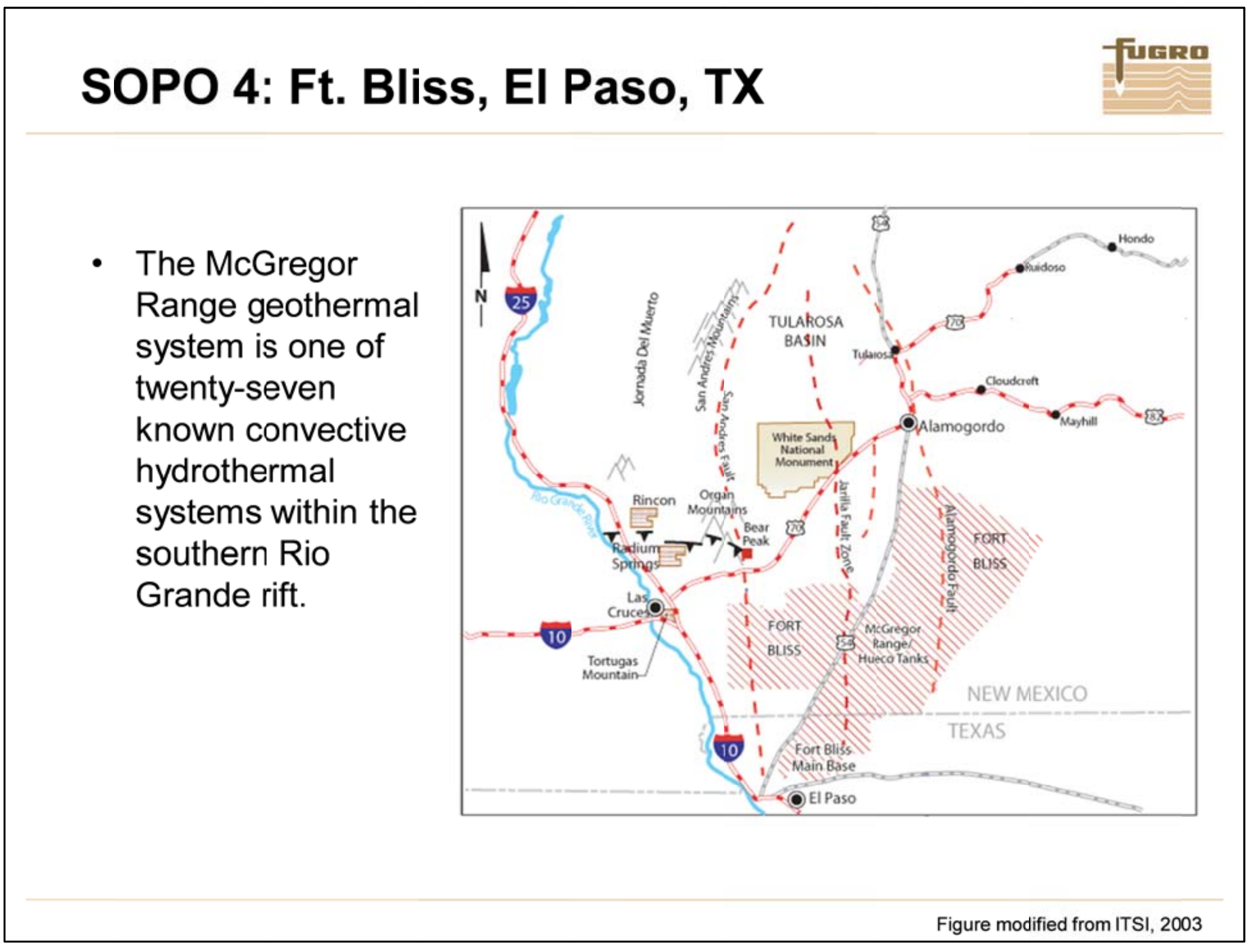


Figure 26: Geothermal Characteristics of El Paso, TX

This is a hydrothermal area, and hence not conducive for a CO_2 EGS.

SOPO 4: Ft. Bliss, El Paso, TX

- The McGregor Range geothermal system is within a major Rio Grande rift structure, the Tularosa-Hueco basin, which is bounded on the western margin by a major east-dipping boundary fault, the East Franklin Mountain fault (Univ. of Utah Energy & Geosciences Institute, 2010).
- The McGregor Range geothermal system occurs along the eastern margin of the basin, within a small intra-basin uplift. This uplift is partially buried by basin fill.
- Measurements in test wells have shown that the thermal waters within the system have temperatures as high as 89° C.

Figure 27: Hydrothermal Characteristics of El Paso, TX

A conceptual cross section for the area of interest, consistent with known measurements in the area, is provided below.

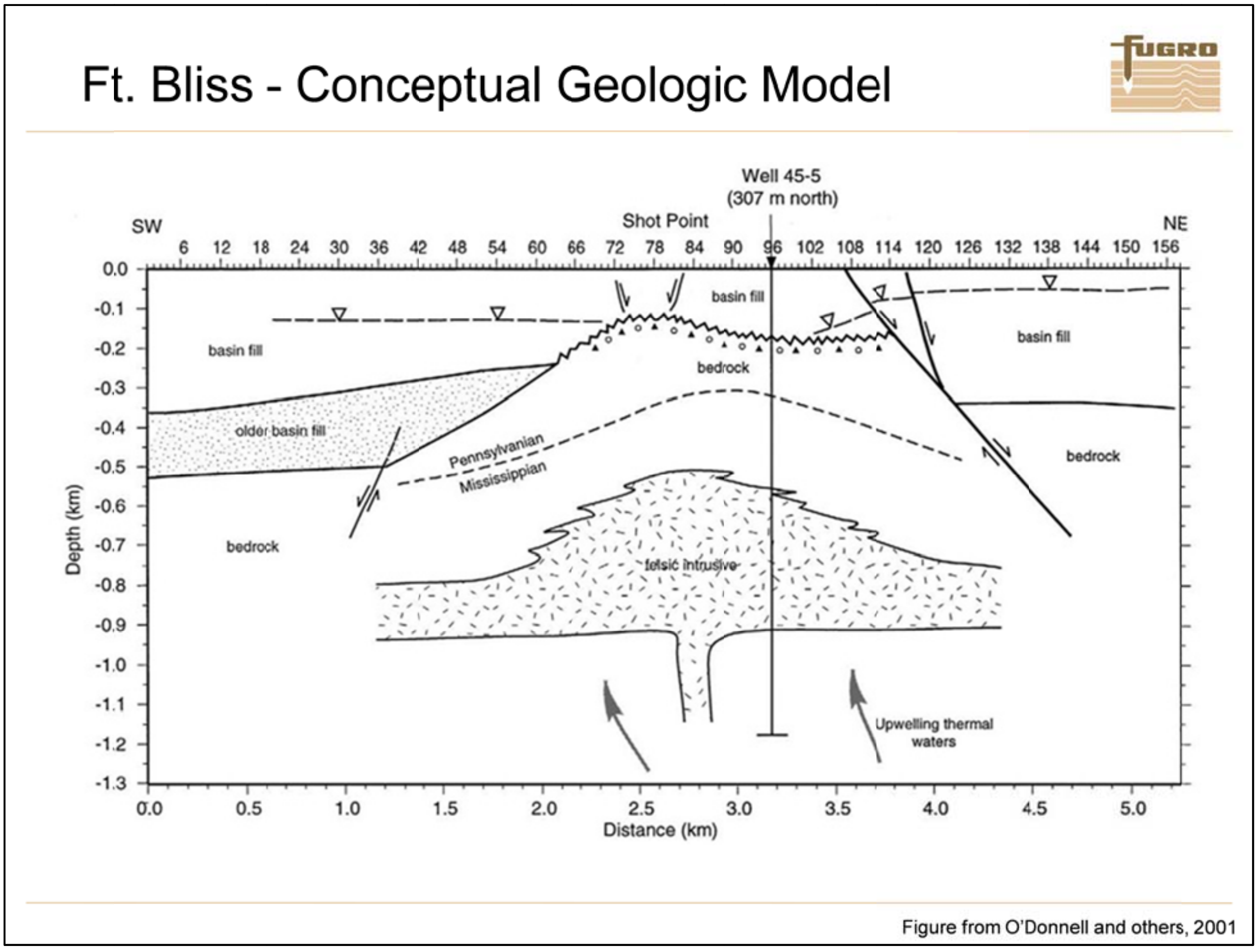


Figure 28: Conceptual Geologic Model for Ft. Bliss, TX

The well design for Ft. Bliss, which will be a water EGS, is provided below.

+

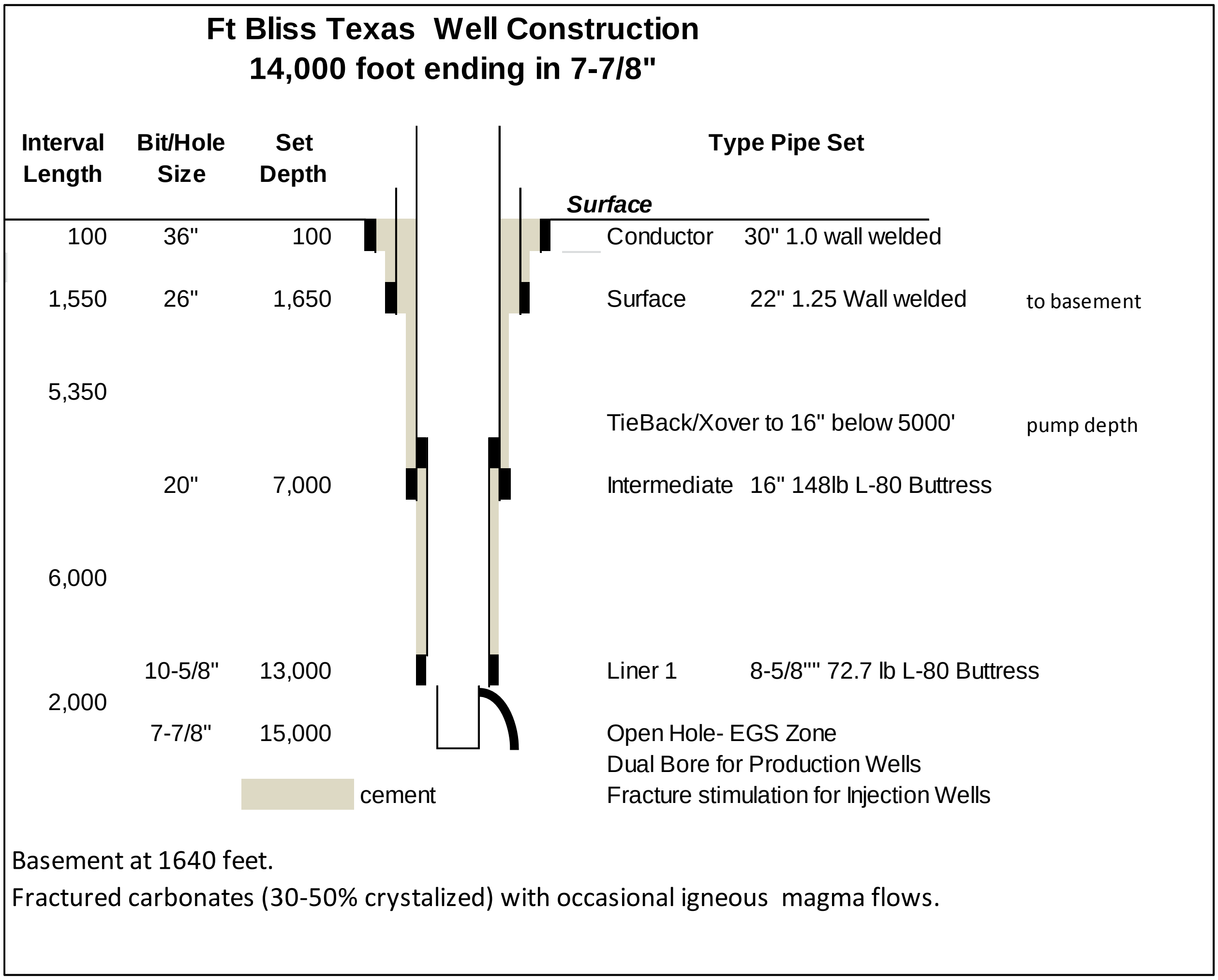


Figure 29: 8 Inch Diameter, 14,000 foot Well Design for Water EGS at Fort Bliss, TX, SOPO 4

Based on this well design, with the diesel driven pumps, 20 production wells and 12 injection wells are used. The overall capital cost is summarized below.

Table 45: Summary of Costs for WBS 1-10 –

50 MW Water EGS for Ft. Bliss, TX - SOPO 4

WBS		WBS Element
	50 MW Gross (GT)	
	20 MW Hybrid Pump	
	Diesel Drive	
1.0	$3,710,000	Resource ID / Analysis
2.0	$437,440,792	Reservoir Development
3.0	$38,512,000	Fluid Management (topside)
4.0	$151,000,000	Power generation
5.0	$3,500,000	Integration / Distribution (local)
6.0	$18,000,000	Integration / Distribution (grid)
7.0	$8,730,000	Topside Structures
8.0	$12,041,000	Land Acquisition / Land Use
9.0	$4,130,000	Permits / Approvals
10.0	$14,600,000	Project Management
Total	$691,663,792	

The total cost of $692M cost of the Ft Bliss water EGS project is obviously a radical reduction in capital cost from SOPO 1, which yielded a result of $952M for the 50 MW gross water EGS case at Westover AFB in Massachusetts. Nearly all the cost reduction as modeled herein is from the lower drilling costs of WBS 2. It is also likely that the WBS 3 costs would come down substantially. The team kept the 20 MW of pumping power required for pumping through granite bedrock in western Massachusetts, providing a conservative estimate of WBS 3 costs.

Unfortunately, while Texas has lower drilling costs than Massachusetts, is also has substantially lower electric rates. In fact, at the summary level, even with this reduction in capital costs, this project would not be viable at the low 4-6 cents/kW-hr wholesale prices in Texas. However, there is a desire for some portion of the power generation to be renewable – and wind power in Texas is reaping that benefit, as is solar. For the purposes of a quick look, using representative electric rates of $60/MW-hr and $120/MW-hr, wholesale and retail, a summary is provided below that includes an additional premium of $50/MW-hr for renewable energy. Even with this change, the Ft. Bliss EGS is not profitable, unless 100% of the power is sold at retail (in effect a $170/MW-hr PPA selling rate).

Table 46: Summary Spreadsheet for 50 MW Water EGS at Fort Bliss, TX - SOPO 4

Parameters:	Water EGS		Comment	
Gross Power	50	MW	Geothermal Gross Power, Not Plant Total	
Net Power	50	MW		
Water Pump Power	20	MW	(from WBS 3)	
Cost of Electricity (retail)	$120	$/MW-hr	(US DOE EIS 2011 TX)	
Cost of Electricity (wholesale)	$60	$/MW-hr	(US DOE EIS 2011 TX)	
Renewable Market Class 1 RPS	$50	$/MW-hr	(Need Input)	
Capital Cost	$691,663,792	(roll up)	(from capital sheet)	
Cost of Capital	7.0%	(high)	(variable)	Years
Annual Capital Cost	$65,288,169	(30 year)	(calculation)	20
O&M Cost	$10	$/MW-hr	2007 GRC Presentation	
Availability	99.5%	(uptime)	(guess)	
Cost Item	$			
Annual Capital Cost	$65,288,169		Escalation Rate (%/year)	
O&M Cost	$4,358,100		2.0%	
O&M Cost Engines	$2,273,504			
Purchased Costs (Fuel / Electricity)	$7,435,621		1.811361584	(30 year)
Total Annual Cost	$79,355,394			
	Revenue (1st Year)		Revenue (30th Year)	
		Percent	Impact of Escalation in Electric Costs	
Offset of Retail Electricity	$26,148,600	50.0%	$47,364,570	
Wholesale Electricity	$13,074,300	50.0%	$23,682,285	
Renewable Market Class 1 RPS	$21,790,500		$21,790,500	
Renewable Investment Tax Credit	$8,716,200		(Zero After 10 Years)	
Total Revenue	$69,729,600		$92,837,354	
Profit / Loss	($9,625,794)		$13,481,960	

It is somewhat surprising that the result for Ft. Bliss was not more positive financially, given that there is active geothermal development in the area. More important than the accuracy of our specific profit / loss numbers is how those numbers change with location and technology. Ft. Bliss is a markedly better environment for a Water EGS than Westover AFB (projected loss $35M in the first year, not $9M).

Mountain Home AFB CO_2 EGS, with SOPO 3 Generation and Drilling Technology Improvements

An overview of the geology of the Mountain Home AFB location is provided in the following figures.

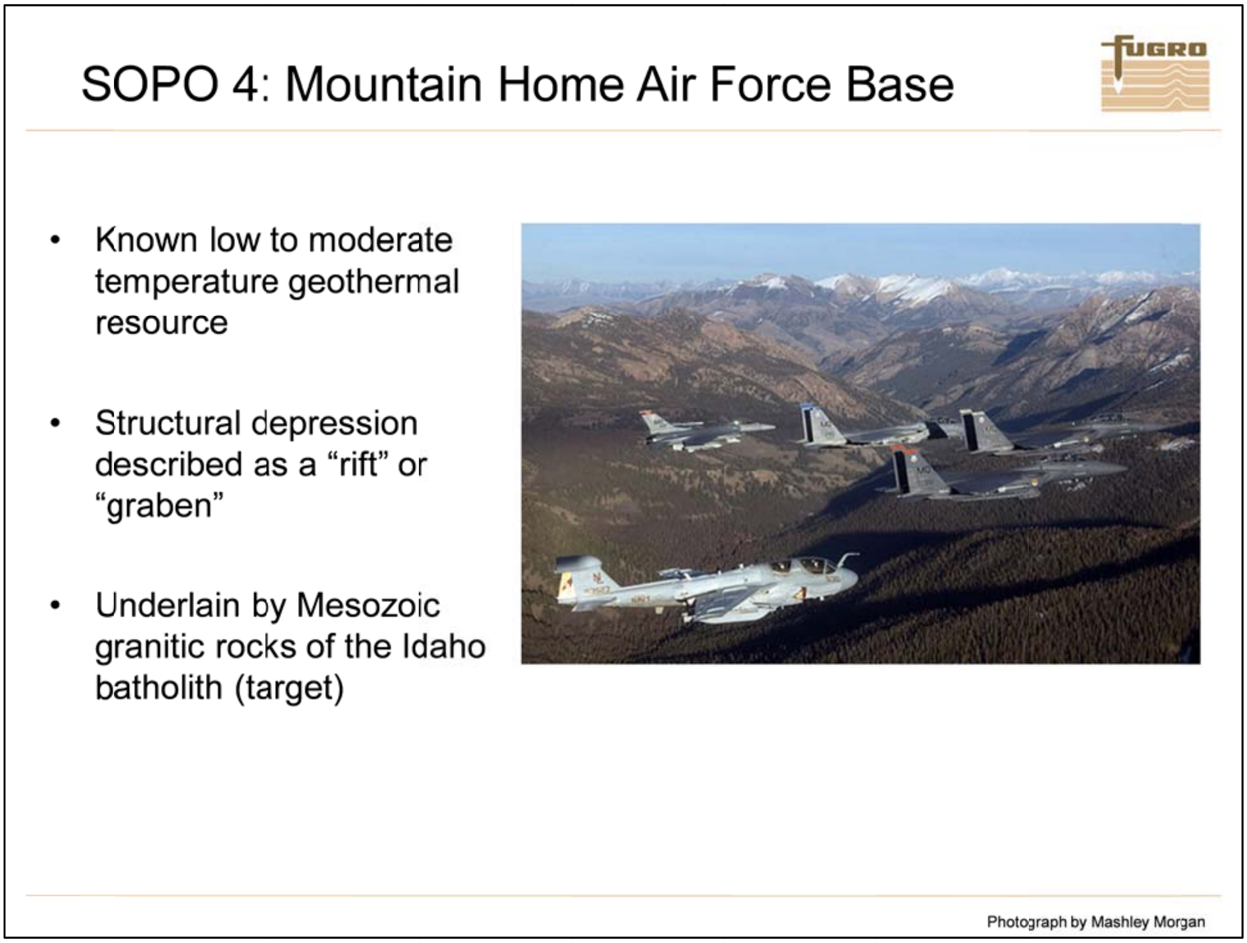


Figure 30: Geology of Mountain Home AFB, ID

SOPO 4: Mountain Home Air Force Base

- Source of heat is emplacement of large heat source 10 to 15 million years ago (mafic intrusion)
- The Idavada Group aquifer (silicic volcanic rocks overlying Columbia River basalts) is the major producing geothermal reservoir.

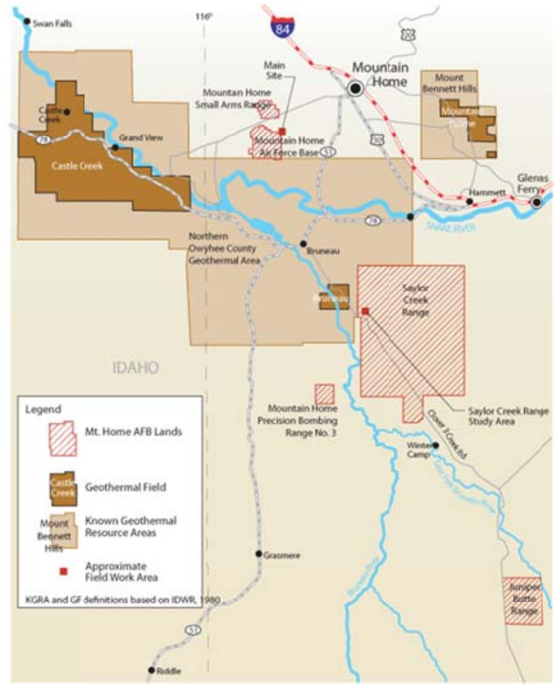


Figure from ITSI, 2003

Figure 31: Geological Characteristics of Mountain Home AFB, ID

A conceptual cross section for the area of interest, consistent with known measurements in the area, is provided below.

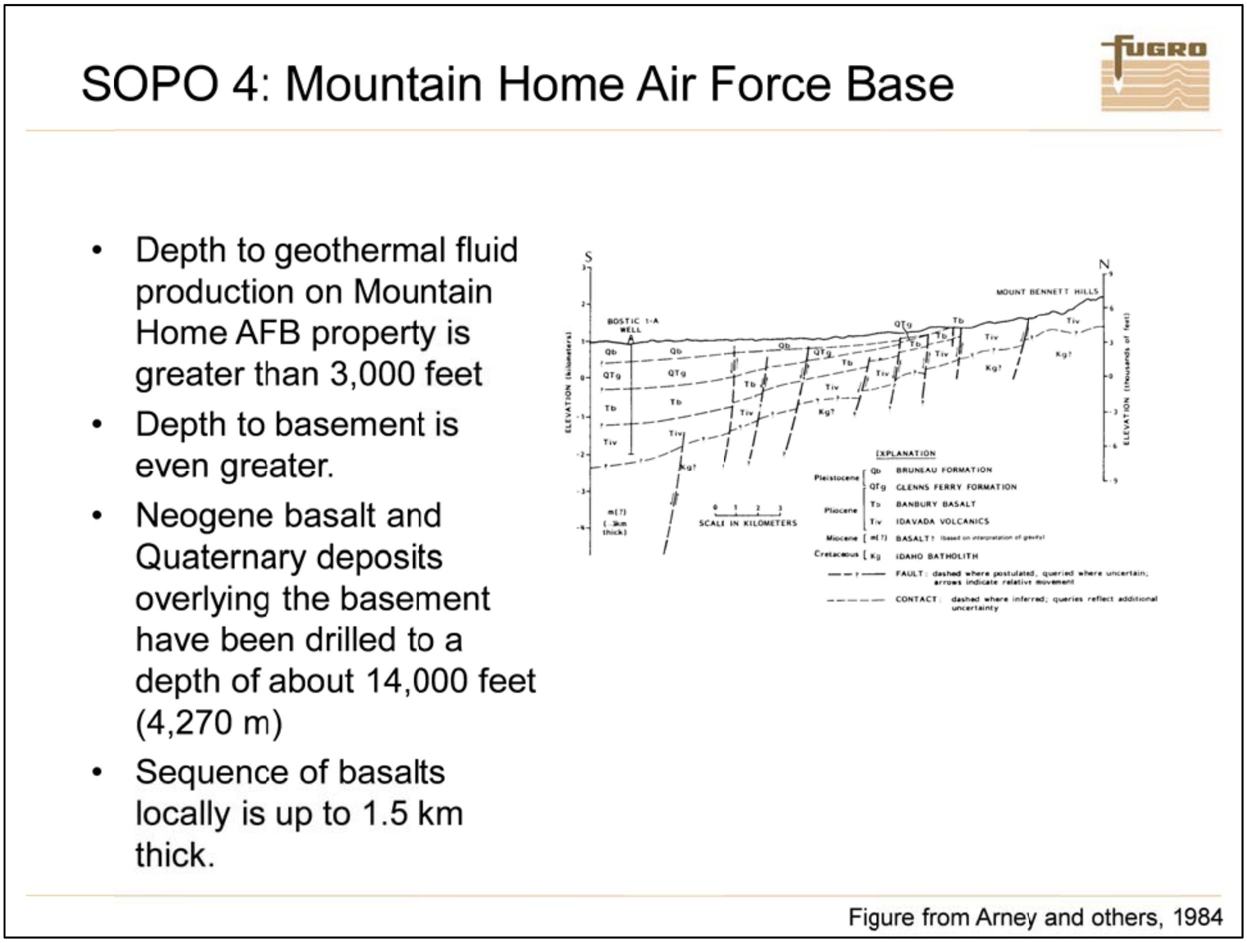


Figure 32: Cross Section of the Geology of Mountain Home AFB, ID

The well design for Mountain Home, which will be a CO_2 EGS, is provided below.

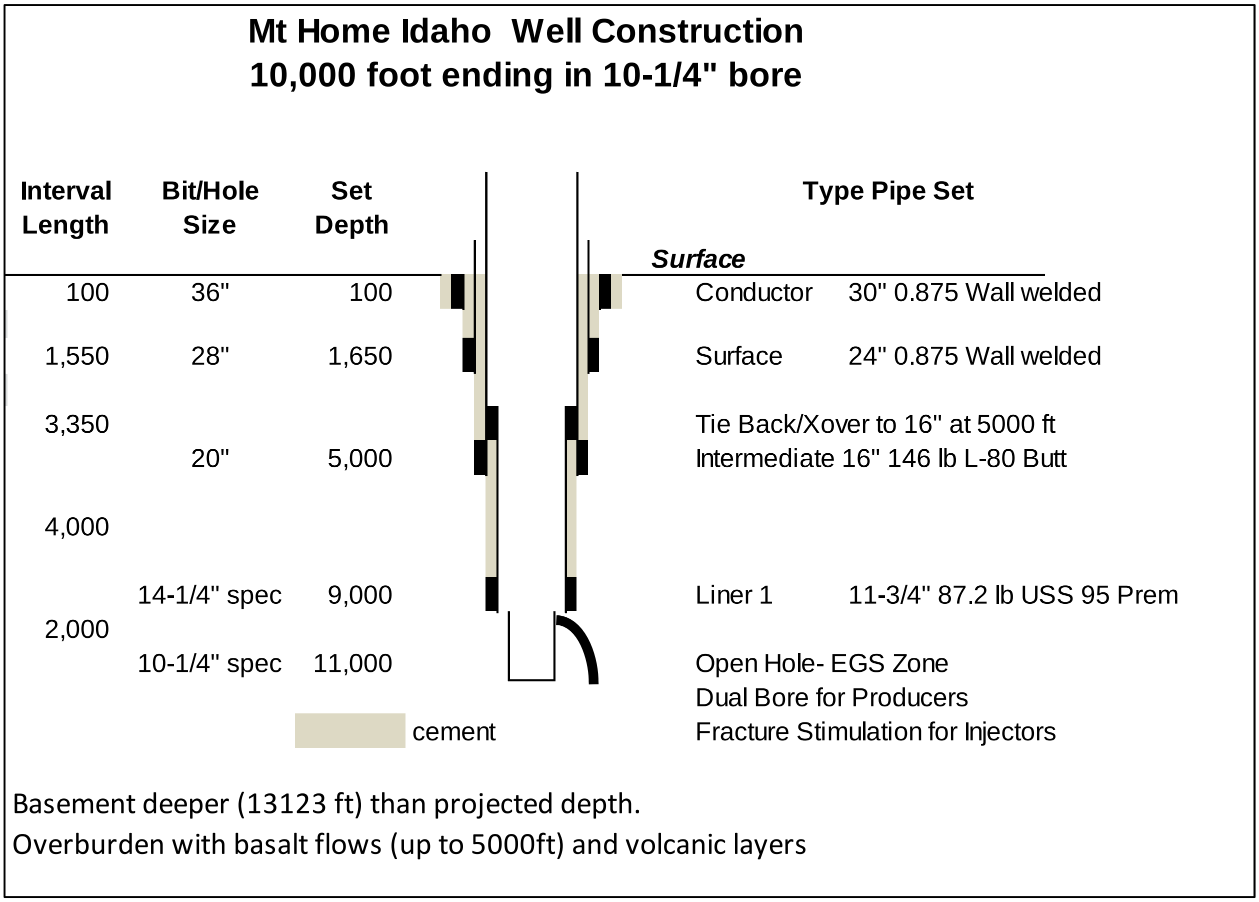


Figure 33: 10 Inch Diameter, 10,000 foot Well Design for CO_2 EGS at Mountain Home AFB, ID, SOPO 4

Based on this well design, we will use 9 injector wells and 16 production wells. While the local geographic information indicates that the basement is below the depth shown (which would mean CO_2 EGS would not work, CO_2 would not be captured), we will assume that the detailed survey of WBS 1 that would be undertaken in a real project would find a local area with a target nearer the surface.

The overall capital cost is summarized below.

Table 47: Summary of Costs for WBS 1-10, 50 MW CO_2 EGS

at Mountain Home AFB, ID, SOPO 4

WBS	Capital Cost	WBS Element
	50 MW Net	
1.0	$3,710,000	Resource ID / Analysis
2.0	$677,083,594	Reservoir Development
3.0	$79,714,328	Fluid Management & CO2 (filling)
4.0	$70,000,000	Power generation
5.0	$3,500,000	Integration / Distribution (local)
6.0	$18,000,000	Integration / Distribution (grid)
7.0	$8,080,000	Topside Structures
8.0	$6,526,000	Land Acquisition / Land Use
9.0	$4,934,000	Permits / Approvals
10.0	$11,244,167	Project Management
Total	$882,792,089	

The total cost of $883M for CO_2 EGS with SOPO 3 technology improvements in Idaho compares to a cost of $1.1B for a similar project at Westover AFB in MA. Though the depth of the well is shallow, these capital costs reflect the tough drilling associated with thick basalt layers.

Table 48: Summary Spreadsheet for 50 MW CO_2 EGS at Mountain Home AFB, ID, SOPO 4

Parameters:	Water EGS		Comment	
Geothermal Power (Net)	50	MW	Geothermal Net Power	
Total Net Power	57	MW	Yearly Total (Not Including Filling)	
CO2 System Net Power (extra to be sold)	7	MW	(from WBS 3)	
Cost of Electricity (retail)	$120	$/MW-hr	(Need a valid input)	
Cost of Electricity (wholesale)	$60	$/MW-hr	(Need a valid input)	
Renewable Market Class 1 RPS	$50	$/MW-hr	(Need a valid input)	
Capital Cost	$882,792,089	(roll up)	(from capital sheet)	
Retail / Wholesale Split Filling System (default 100% retail)		100.0%	Retail %	
One Time Power Generated (filling system)	221929	MW-hr	(from WBS 3)	
Capital Cost Adjustment, One Time Power	$26,631,494	Filling Sys.	(Retail Portion)	
Capital Cost Adjustment, One Time Power	$0	Filling Sys.	(Wholesale Portion)	
Adjusted Capital Cost (Minus Filling Income)	$856,160,595			
Cost of Capital	7.0%	(high)	(variable)	
	20	(30 year default)		
Annual Capital Cost	$80,815,504		(calculation)	
O&M Cost	$10	$/MW-hr	2007 GRC Presentation	
Availability	99.5%	(uptime)	(guess)	
Cost Item	$			
Annual Capital Cost	$80,815,504		Escalation Rate (%/year)	
O&M Cost	$4,358,100		2.0%	
O&M Cost Engines	$598,496			
Purchased Costs (Fuel / CO2)	$1,962,306		1.811361584	(30 year)
Total Annual Cost	$87,734,406			
	Revenue (1st Full Year)		Revenue (30th Year)	
		Percent	Impact of Escalation in Electric Costs	
Offset of Retail Electricity	$29,821,769	50.0%	$54,018,007	
Wholesale Electricity	$14,910,885	50.0%	$27,009,004	
MA Renewable Market Class 1 RPS	$24,851,474		$24,851,474	
Renewable Investment Tax Credit	$9,940,590		(Zero After 10 Years)	
Total Revenue	$79,524,718		$105,878,486	
Profit / Loss	($8,209,687)		$18,144,080	

Though there is plenty of heat in the area, Mountain Home AFB also does not look attractive for geothermal development. It is better as calculated herein than Ft. Bliss, with the break even (make money) point with a retail / wholesale split of 80/20.

China Lake CO_2 EGS Using Naturally Occurring CO_2

An overview of the geology for the China Lake location in Coso, CA is provided in the following figures.

Coso Geothermal Field

- Geothermal field is hosted in Mesozoic intrusive rocks (granite).
- Main sources of permeability in the geothermal field are active faults.

Figure 34: Coso Geothermal Field Characteristics

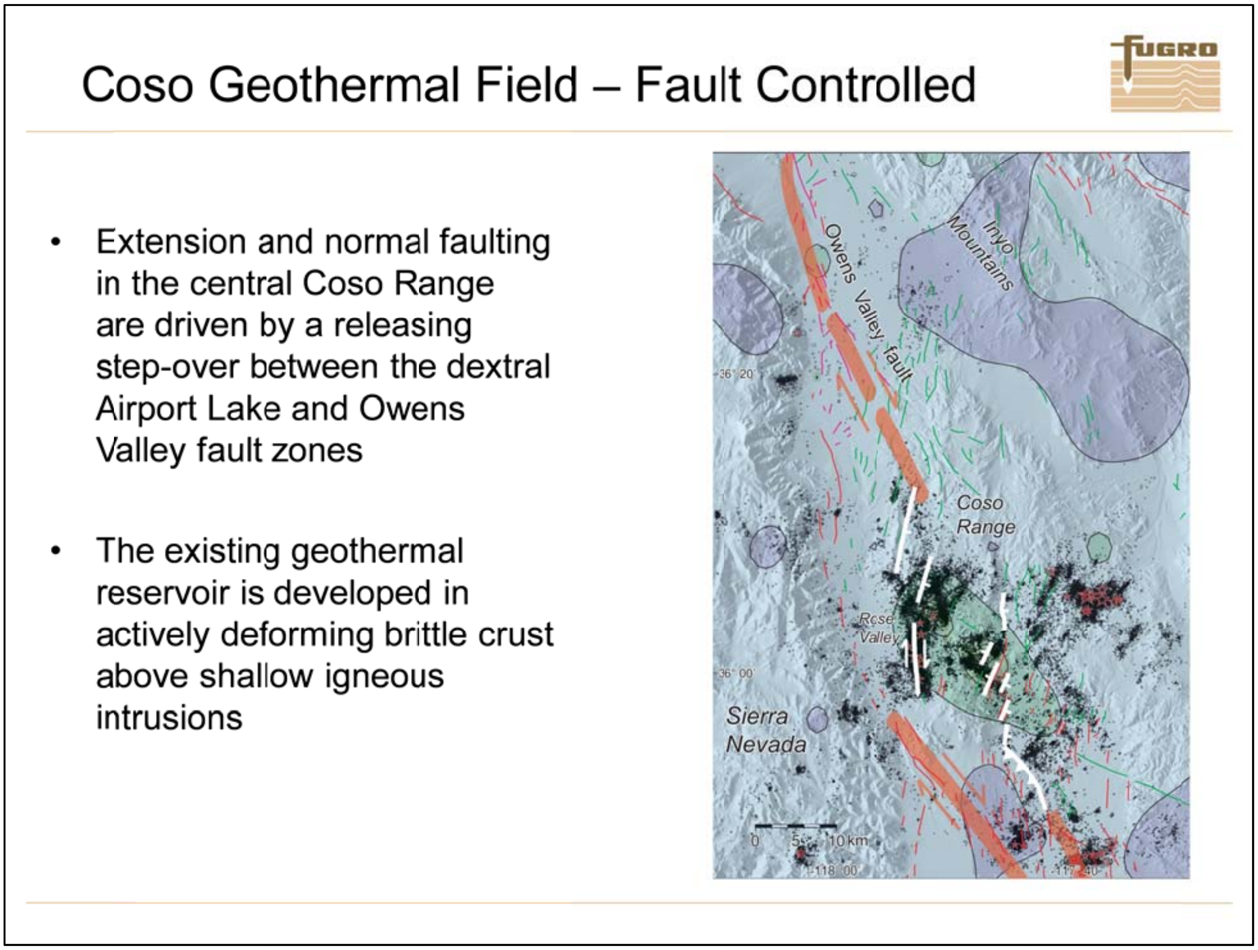


Figure 35: Coso Geothermal Field - Fault Controlled

A conceptual cross section for the area of interest, consistent with known measurements in the area, is provided below.

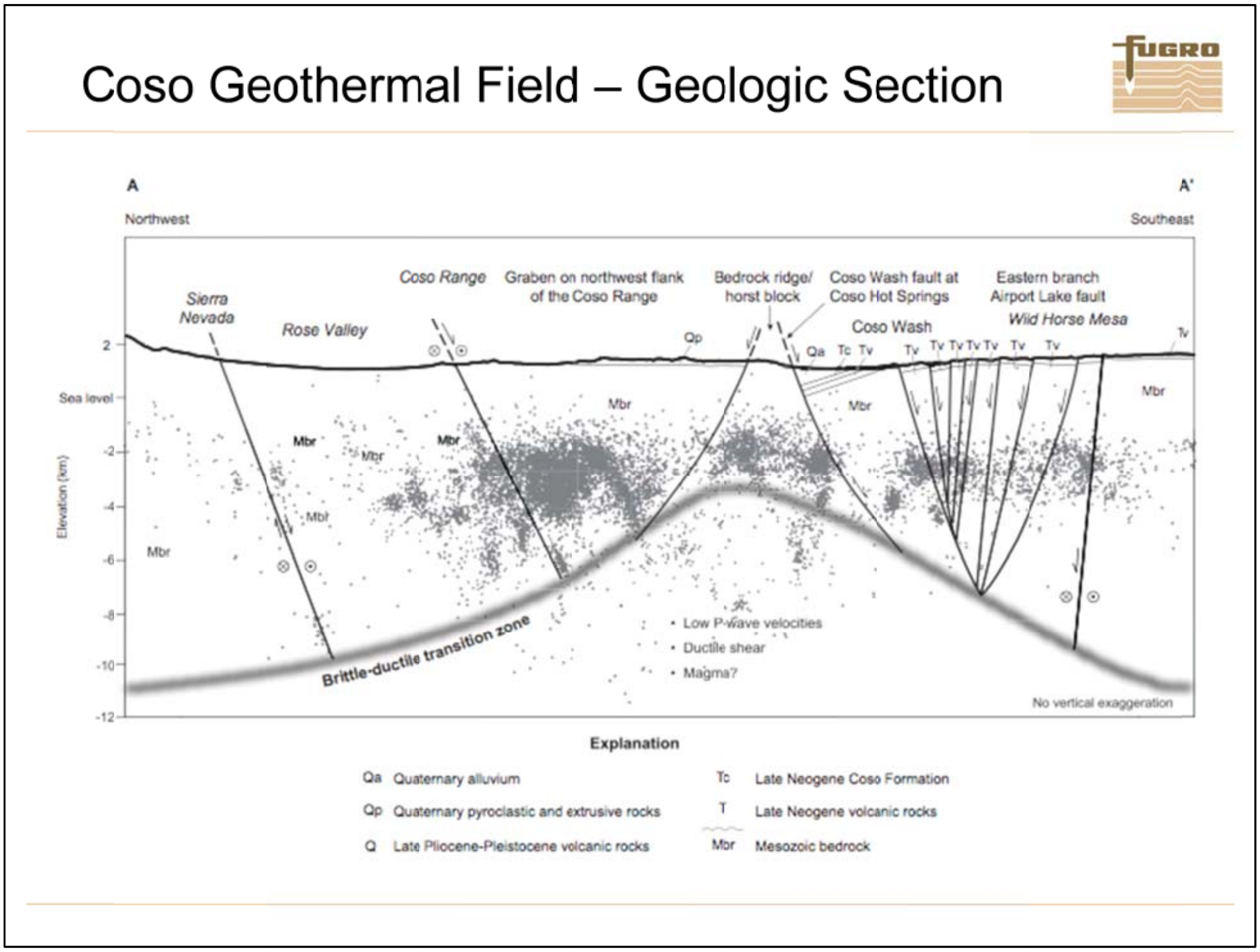


Figure 36: Cross Section of Geology of Coso, CA

Coso Geothermal Field – Fault Controlled

- Bedrock is covered with thin veneer (hundreds of meters) of pyroclastics and/or alluvium in the vicinity of the geothermal field.
- Depth to bedrock varies significantly depending on the site.
- Thermal gradient drops off abruptly with distance from the geothermal field, but may still be higher in parts of the Coso Range than Mt. Home and Ft. Bliss.

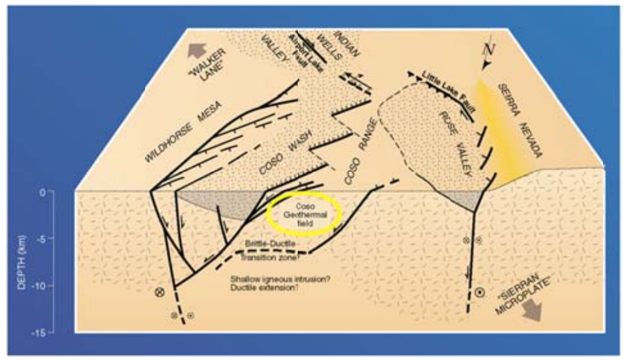


Figure 37: Coso Geothermal Field Cross Section Showing Fault Zones

The well design for China Lake, which will be a CO_2 EGS, is provided below.

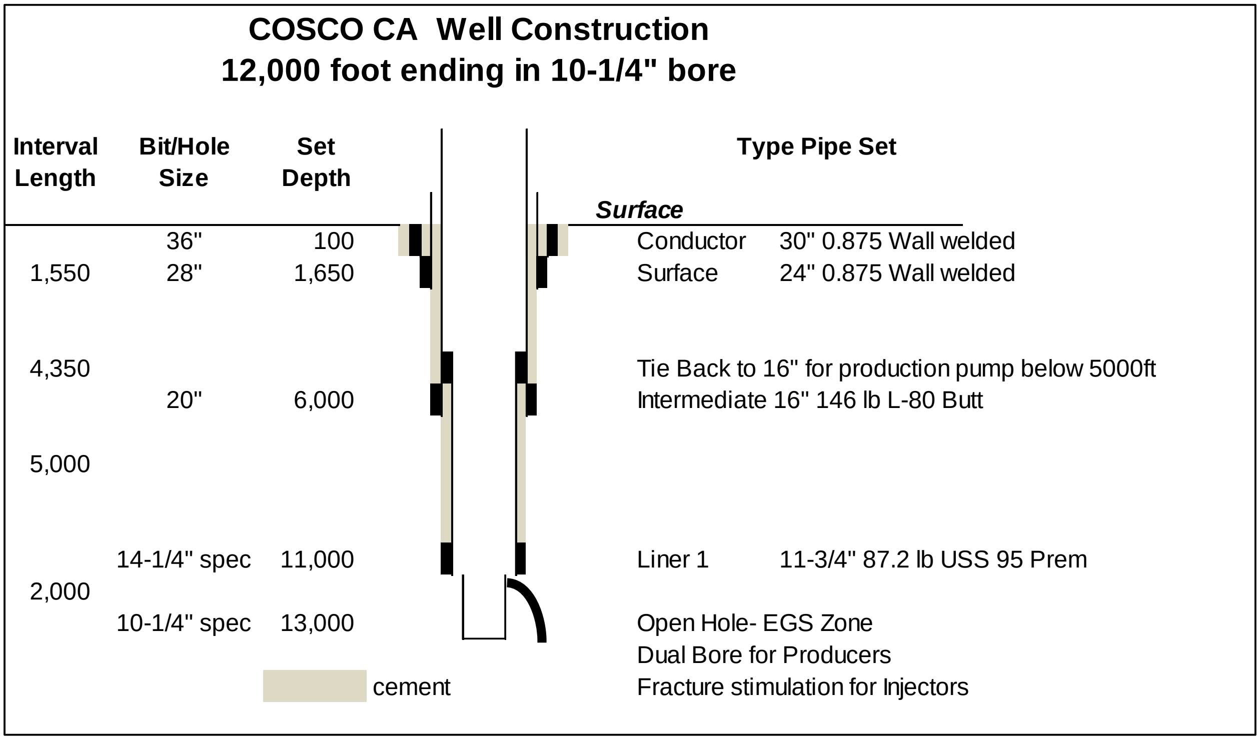


Figure 38: 10 Inch Diameter, 12,000 foot Well Design for CO_2 EGS at Coso, CA, SOPO 4

Based on this well design, we will use 9 injector wells and 16 production wells.

The overall capital cost is summarized below. This model assumes that CO_2 is naturally occurring.

Table 49: Summary of Costs for WBS 1-10, 50 MW CO_2 EGS at Coso, CA - SOPO 4

WBS	Capital Cost	WBS Element
	50 MW Net	
1.0	$3,710,000	Resource ID / Analysis
2.0	$484,774,203	Reservoir Development
3.0	$28,570,000	Fluid Management & CO2 (filling)
4.0	$70,000,000	Power generation
5.0	$3,500,000	Integration / Distribution (local)
6.0	$18,000,000	Integration / Distribution (grid)
7.0	$8,080,000	Topside Structures
8.0	$4,996,000	Land Acquisition / Land Use
9.0	$5,456,307	Permits / Approvals
10.0	$11,244,167	Project Management
Total	$638,330,676	

The total cost of $638M is the lowest system capital cost of any of the projects studied herein, even though these reflect the step of drilling to a depth of 13,000 ft to generate the thermal siphon.

The summary cost sheet is provided below. The China Lake area in Coso, CA area is of course flush with geothermal energy and existing, successful geothermal power plants. This is a clearly profitable case.

Table 50: Summary Spreadsheet for 50 MW CO_2 EGS for Coso, CA, SOPO 4

Parameters:	CO2 EGS		Comment	
Geothermal Power (Net)	50	MW	Geothermal Net Power	
Total Net Power	50	MW	Yearly Total (Not Including Filling)	
CO2 System Net Power (extra to be sold)	0	MW	(from WBS 3)	
Cost of Electricity (retail)	$150	$/MW-hr	(US DOE EIS 2011)	
Cost of Electricity (wholesale)	$100	$/MW-hr	(Need Input)	
MA Renewable Market Class 1 RPS	$50	$/MW-hr	(Need Input)	
Capital Cost	$638,330,676	(roll up)	(from capital sheet)	
Cost of Capital	7.0%	(high)	(variable)	
	20	(30 year default)		
Annual Capital Cost	$60,253,900		(calculation)	
O&M Cost	$10	$/MW-hr	2007 GRC Presentation	
Availability	99.5%	(uptime)	(guess)	
<u>Cost Item</u>	<u>$</u>			
Annual Capital Cost	$60,253,900		Escalation Rate (%/year)	
O&M Cost	$4,358,100		2.0%	
O&M Cost Engines	$240,960			
Purchased Costs (Fuel / CO2)	$1,849,206		1.811361584	(30 year)
Total Annual Cost	$66,702,166			
	<u>Revenue (1st Full Year)</u>		<u>Revenue (30th Year)</u>	
		Percent	Impact of Escalation in Electric Costs	
Offset of Retail Electricity	$32,685,750	50.0%	$59,205,712	
Wholesale Electricity	$21,790,500	50.0%	$39,470,475	
MA Renewable Market Class 1 RPS	$21,790,500		$21,790,500	
Renewable Investment Tax Credit	$8,716,200		(Zero After 10 Years)	
Total Revenue	$84,982,950		$120,466,686	
Profit / Loss	$18,280,784		$53,764,520	

The assumptions above are based on locally available CO_2 captured from existing geothermal power system gas vents. The cost of CO_2 would be "zero", but WBS 3 (see Appendix) includes a nominal cost of $40/ton for compression and clean up. This cost may be high, more detailed assessment of the actual makeup of the CO_2 / Water Vapor / Other? mixture would be required to design a gas clean up and compression system and estimate the cost.

China Lake CO_2 EGS with SOPO 3 Generation and Drilling Technology

As a final effort, a variant of China Lake is costed with on-site generation of CO_2. This case is examined since the cost of CO_2 capture and cleanup from existing geothermal power plants is unknown and only estimated in the previous section. WBS 3 costs for pumping and backup power for China Lake, SOPO 4, is provided below.

Table 51: Cost Summary for WBS 3 – CO_2 –

50 MW CO_2 EGS at Coso, CA, SOPO 4 – Hybrid Generated CO_2

WBS	Cost	Item	Basis / Comment							
3.0	**$93,552,328**	**CO2**	Mega Ton Required to fill =			0.5	MT	Number of 25 MW Turbine Modules		
3.1	**$42,000,000**	Oxygen Plant (for filling system)	1000 TPD Praxair Quote					1		
3.2	**$18,500,000**	25 MW Gross Combustion System (for filling)	25 MW Turbines @ <$0.5M/MW, Simple Combustion Can							
		Net Power MW	12.75					Net Power Per Module Calculation		
		For 950 F @ 900 psig, Diluent Ratio, defined as the mass of water per mass of fuel and oxidant is =					1.4125	25	MW	(Gross)
		Net Exhaust will be about 77% steam by mass	Net Exhaust is 89% Steam by Volume.					10	MW	(ASU)
		Initial Results (using Steam Only in the Steam Turbine, 89% Steam by volume will be close)						2	MW	(CO2 Compression, Cooling, Liquid Pumping)
		Total Massflow =	70	lbm/sec				0.25	MW	(H2O Pumping)
		Combustion Power (STP) =	450.2	MMBTU/HR						
		Methane Flow Rate =	5.8	lbm/sec		21551	BTU/lbm	(LHV)		
		Oxygen Flow Rate =	23.2	lbm/sec	1003	tons / day				
		Carbon Dioxide Generation Rate=	16.0	lbm/sec	689	tons / day		251634	tons / year	
		Diluent Water Flow Rate =	41.0	lbm/sec	294.9	gpm		Diluent Pump Power =		
		Oxygen and Methane Compressed As Liquids (Part of Praxair System)								
3.3	**$26,426,000**	CO2 Top Off Modules (CCD System)	Generates 70 TPD CO2, At Pressure Per Diesel Set (2 is baseline at 140 TPD)							
		Details:								
		Genset	6913000	Cost of 1 32/40 Dual Fuel Engine & Generator plus Auxiliaries & Controls						
		VPSA, 100 Ton Per Day	3900000	926 kW						
		Top Off Power Level	6160	kWm = 100% rated load for one 16 cylinder, FM/MAN 32/40 engine						
		Generator Efficiency	0.97	5975	kW					
		Specific Fuel Consumption	6040	BTU/hp-hr @ 100% load						
		Fuel Price ($/mmBTU)	4.00	Current cost of natural gas						
		ORC (800 kW each)	2400000	22% cycle efficiency 750 F exhaust waste heat, 3.6 MW heat available to 120 F						
		Number of dual fuel engines	2	# engines @ 70 TPD required to make CO2						
		Hours of operation per year	8000	Assumes 97% availability or uptime per year + time for maintenance						
3.4	**$2,000,000**	Electric Blower to Start Thermal Siphon	1000 hp multi-stage compressor, electric drive (Solar Turbines)							
3.5	**$1,790,000**	Diesel Genset for Backup Power	ROM							
		Details (for backup genset as well)								
			1790000	Cost of 1 OP Dual Fuel Engine & Generator plus Auxiliaries & Controls						
		Power Level	1506	kWe = 100% rated load at the generator output for 1x6 cylinder OP engine						
		Specific Fuel Consumption	6400	BTU/hp-hr @ 100% load						
		Fuel Price ($/mmBTU)	4	Current cost of natural gas						
		Number of dual fuel engines (for CO2)	0	Assumes 32/40 for CO2 Production						
			1	Backup Genset						
		Hours of operation per year	8000	Assumes 97% availability or uptime per year + time for maintenance						
3.6	**$400,000**	Filtration	ROM							
3.7	**$90,000**	Freeze Protection	ROM							
3.8	**$1,250,000**	CO2 Compression (Brute Force, 5 Stage Compi	625000	69 TPD	400 hp (electric)					
		Number of Compression Modules	2							

Including the above estimate of the cost for CO_2, we have the total project summary sheet:

Table 52: Summary Spreadsheet for 50 MW CO_2 EGS with Hybrid CO_2 - SOPO 4

Parameters:	Water EGS		Comment	
Geothermal Power (Net)	50	MW	Geothermal Net Power	
Total Net Power	63	MW	Yearly Total (Not Including Filling)	
CO2 System Net Power (extra to be sold)	13	MW	(from WBS 3)	
Cost of Electricity (retail)	$150	$/MW-hr	(Need a valid input)	
Cost of Electricity (wholesale)	$100	$/MW-hr	(Need a valid input)	
Renewable Market Class 1 RPS	$50	$/MW-hr	(Need a valid input)	
Capital Cost	$703,388,004	(roll up)	(from capital sheet)	
Retail / Wholesale Split Filling System (default 100% retail)		100.0%	Retail %	
One Time Power Generated (filling system)	221929	MW-hr	(from WBS 3)	
Capital Cost Adjustment, One Time Power	$33,289,367	Filling Sys.	(Retail Portion)	
Capital Cost Adjustment, One Time Power	$0	Filling Sys.	(Wholesale Portion)	
Adjusted Capital Cost (Minus Filling Income)	$670,098,638			
Cost of Capital	7.0%	(high)	(variable)	
	20	(30 year default)		
Annual Capital Cost	$63,252,571		(calculation)	
O&M Cost	$10	$/MW-hr	2007 GRC Presentation	
Availability	99.5%	(uptime)	(guess)	
<u>Cost Item</u>	<u>$</u>			
Annual Capital Cost	$63,252,571		Escalation Rate (%/year)	
O&M Cost	$4,358,100		2.0%	
O&M Cost Engines	$598,496			
Purchased Costs (Fuel / CO2)	$1,962,306		1.811361584	(30 year)
Total Annual Cost	$70,171,473			
	<u>Revenue (1st Full Year)</u>		<u>Revenue (30th Year)</u>	
		Percent	Impact of Escalation in Electric Costs	
Offset of Retail Electricity	$40,884,179	50.0%	$74,056,031	
Wholesale Electricity	$27,256,119	50.0%	$49,370,687	
MA Renewable Market Class 1 RPS	$27,256,119		$27,256,119	
Renewable Investment Tax Credit	$10,902,448		(Zero After 10 Years)	
Total Revenue	$106,298,865		$150,682,837	
Profit / Loss	$36,127,392		$80,511,364	

This is the most profitable geothermal power plant studied under this effort, by far. The fact of the matter is that <u>generating your own CO_2 for geothermal power is in most cases cheaper than "free" CO_2</u>, since the power sold to generate your own generates additional revenue for the project, and processing someone else's CO_2 generates only expense.

Limitations of the Effort – Desire for More Data and Tools

Although this was a reasonably well funded project, with nominally 25% cost share from the participants and the balance of the $1.6M project funds provided by DOE, there are still serious limitations to this cost analysis that should be addressed in the future. We will mention only three.

- First and foremost, there is very little available data nationally, with believable, repeatable, consistent geothermal gradients east of the Mississippi. In fact the widely used heat maps from SMU changed during the course of the project, with the "hot spot" previously in Massachusetts near the location of this project disappearing and moving closer to New York City!! This change, per discussion with Dave Blackwell at SMU, was actually a result of more data in West Virginia that drove a change in the model. A few shallow test wells, in rural areas, or in areas with Government owned land, but near the grid would be money well spent. One of the best places to do this might be Westover AFB in Chicopee, MA.
- Secondly, the parameters associated with CO_2 EGS, to include new types of power generation, gas generation, and ultimately corrosion control, are not in GETEM or any other refereed geothermal cost model. While the results of this project are interesting, CO_2 EGS with hybrid CO_2 generation being the highest performing geothermal system, even in China Lake. The basic tools for CO_2 EGS costing need to be refined and captured in an overarching tool like GETEM.
- Third, accurate reservoir modeling is mandatory to avoid or try to avoid very serious surprises with a CO_2 EGS system. The actual porosity of the reservoir, and the ability to seal the reservoir, or said another way only fracture locally deep in solid bedrock are not well understood. A factor of ten change in a parameter like porosity or leakage rate is not impossible to rule out, and would totally change the basic conclusion herein, at least in some of the cases modeled.

Summary

Substantial unexploited opportunity exists for the US, and the world, in Enhanced Geothermal Systems (EGS). As a result of US DOE investment, new drilling technology, new power generation equipment and cycles enable meaningful power production, in a compact and modular fashion; at lower and lower top side EGS working fluid temperatures and in a broader range of geologies and geographies. This cost analysis effort supports the expansion of Enhanced Geothermal Systems (EGS), furthering DOE strategic themes of energy security and sub goal of energy diversity; reducing the Nation's dependence on foreign oil while improving the environment.

This cost analysis provided a baseline cost for a 50 MW Geothermal Power Plant in a difficult environment (Massachusetts), and then assessed how that cost would change as a function of:

- Geothermal Working Fluid (CO_2 vs. Water)
- Drilling and Completion Technologies
- CO_2 Generation Technology
- Other Locations

Key take away points are as follows:

1. A 50 MW EGS power plant is probably not economically viable in Western MA. This would be a $1.1B dollar project, and the single case that did make money in Massachusetts was: alternate working fluids (CO_2), available (TRL6) technology in well casing and CO_2 generation, with power sold at retail rates. All the other cases lost massive amounts of money.
2. Water can be technically used as a geothermal working fluid in essentially any location.
3. CO_2 cannot be technically used as a geothermal working fluid in essentially any location. Certain sites are better suited for sequestration, and if CO_2 EGS power systems are employed at those sites the costs associated with filling and top off of CO_2 will significantly and negatively impact the results.
4. In sites where CO_2 use is technically viable, i.e. where the reservoir can be filled and pressurized, a CO_2 EGS will in general out perform a water EGS, both technically (efficiency) and economically (LCOE).
5. For deep EGS wells, especially with CO_2, in the more challenging areas, the dominant cost was well casing (50-70% of cost). Drilling technology (faster drilling) is good and will lower cost, and DOE investment in that area must continue. However, DOE investment in well casing technology could have the greatest impact / enable the use of CO_2 EGS.
6. Unless natural CO_2 or pipeline CO_2 at low cost exists, CO_2 EGS is essentially unaffordable unless the CO_2 is generated / captured in some type of hybrid system. If DOE is interested in CO_2 EGS, it should invest in / leverage oxy fuel or other CO_2 capture technology and consider CO_2 EGS a hybrid fossil / geothermal system.
7. Reservoir modeling / analysis, in particular for CO_2, requires further investment. Significant questions exist on the filling dynamics / leakage rate / sequestration rate. We simply do not

know that a CO_2 EGS can actually be engineered. This needs to be better modeled, and demonstrated, at least at the huff and puff level.

8. The availability of data east of the Mississippi, especially in the Northeast, is sparse and volatile. During the conduct of this report, significant update to geothermal heat maps was published impacting New England, and there are no test bores or actual data to validate those estimates.
9. In the Water EGS locations studied, both Texas and MA, the diesel driven water pump versions were significantly more cost effective than electric driven pumps (with electric power from the geothermal plant). This is likely to remain true as long as natural gas prices stay low ($4/MMBTU used herein).
10. Of the four locations chosen, Western MA, El Paso TX, Mountain Home, ID, and China Lake, the differences between the first three were significant in total cost, but not profitability. Only China Lake was exceedingly profitable. We do not believe this is a general result, but reflects limited time available to select more optimal alternative locations.

Cited References

Balk, R., 1957, Geology of the Mount Holyoke quadrangle, Massachusetts: Geological Society of America Bulletin, v. 68, p. 481–504.

Birch, F., R. F. Roy, and E. R. Decker. 1968. "Heat flow and thermal history in New England and New York." In Studies of Appalachian Geology: Northern and Maritime, eds. E. Zen, W. S. White, J. B. Hadley, and J. B. Thompson, Jr., Interscience, New York, pp. 437451.

Blackwell, D. D. and M. Richards, 2004, Geothermal Map of North America: Amer. Assoc. Petroleum Geologists, 1 sheet, scale 1:6,500,000.

Brophy, G., 2007, Geothermal resource assessment of the New England states, unpublished DOE Report performed under contract DE-FC07-80RA50272.

Geothermal Energy Association (GEA), 2005, Factors affecting cost of geothermal power development. http://www.geoenergy.org/publications/reports/Factors%20Affecting%20Cost%20of%20Geothermal%20Power%20Development%20-%20August%202005.pdf

McGrail, B. P., H. T. Schaef, A. M. Ho, Y.-J. Chien, J. J. Dooley, and C. L. Davidson, 2006, Potential for carbon dioxide sequestration in flood basalts, Journal of Geophysical Research, Vol. 111, B12201 Osberg. P. H.. Yetteraner. R., Rivers. M.. Bothner. W. A. Creasy, J. W.. 1978, Feasibility Study of the Conway Granite as a geothermal energy

Sanyal, S.K. and Butler, S.J. (2005), "An Analysis of Power Generation Prospects From Enhanced Geothermal Systems," Geothermal Resources Council Transactions, Vol. 29.

Tester, Jefferson W., et al. "The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century." Massachusetts Institute of Technology and Idaho National Laboratory, 2006.

Walker, J.D., Sabin, A. E., and Unruh, J.R., 2005, Development of genetic occurrence models for geothermal prospecting: Geothermal Resources Council Transactions, v. 29, p. 309-313.

Zen, E-an, ed., and Goldsmith, R., Ratcliffe, N.M., Robinson, P., and Stanley, R.S., comps., 1983, Bedrock geologic map of Massachusetts: U.S. Geological Survey, 1:250,000, 3 sheets.

OXYFUEL COMBUSTION FOR COAL-FIRED POWER GENERATION WITH CO_2 CAPTURE – OPPORTUNITIES AND CHALLENGES. Kristin Jordal, Marie Anheden, Jinying Yan, Lars Strömberg. Vattenfall Utveckling AB, 162 87 Stockholm, Sweden, Vattenfall AB, 162 87 Stockholm, Sweden