Geothermal Energy

The Economics of West Virginia's EGS Potential

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GEOTHERMAL ENERGY

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Executive Summary

Conventional geothermal systems, also called hydrothermal systems, produce energy by utilizing the water and steam heated naturally in reservoirs below the Earth's surface. Such resources are widely available throughout the western United States. Improvements in drilling technology have advanced the possibilities of thermal energy production to reach deeper depths and higher temperatures without relying on the natural existence of water, which could allow development of geothermal energy in regions such as West Virginia that lack conventional resources.

Such enhanced geothermal systems (EGS) now have increasing prevalence in power plant demonstrations throughout the world. Reaching depths in excess of 4.5 km, EGS wells allow energy production from thermal resources that have previously been inaccessible. As development continues, EGS could prove competitive with other conventional forms of electricity generation. Both conventional and EGS systems provide consistent, base-load power, a product which to date is dominated by fossil and nuclear resources.

Benefits of Geothermal Energy

Geothermal energy has a smaller environmental impact than fossil fuel power plants in several ways. Geothermal power plants run a closed-loop system to circulate water through the reservoir—whether natural or simulated—and thus consume less water than traditional plants. In addition, the plants boast almost no on-site emissions. Geothermal power plants also require less land per gigawatt hour (GWh) than plants using fossil fuels.

Cost Competitiveness

The levelized energy cost (LEC) is helpful in comparing the cost of operating a geothermal power plant to other power plants using fossil fuel and renewable resources for generation. Recent estimations of the LEC of new generation power plants show that conventional geothermal and conventional coal power plant costs are very comparable (EIA 2010). EGS systems are still considerably more expensive (and are likely to be even more costly in places like West Virginia) but the State's proximity to large electricity demand centers and its position in regional power delivery systems may make future development of this resource very appealing.

Geothermal Resource Potential in West Virginia

It is certain that EGS potential exists in West Virginia. However, the extent of that potential—specifically the depths required to reach a useful temperature—is still unknown. The electricity generation potential in the most geothermal-rich areas in West Virginia has been estimated at 4.5 GW at 2 percent recovery (Google 2011). Based on current research, it can be assumed with near certainty that West Virginia possesses a low- to mid-grade EGS resource and can, therefore, expect relatively higher costs for EGS development. Lower temperatures at deeper depths, as opposed to higher-grade EGS locations, will naturally require more cost and result in lower efficiency systems. Further investigation is required to determine the cost of developing the West Virginia EGS potential.

Many factors with varying degrees of uncertainty influence the potential cost of developing EGS. Initial costs for exploration, engineering and well specifics (including the number of casing intervals, the rate of penetration, bit life and, most importantly, depth) are uncertain. Other important factors are fracturing and stimulation costs, reservoir performance following stimulation and plant capital costs. The certainty of such factors can only be known once further research is completed. Additionally, some risk can be expected prior to completion of drilling and development of a geothermal site, including potential flow rates and actual temperature of the geothermal resource. This risk subsides greatly once specific site characteristics are identified.

West Virginia could potentially benefit from an unconventional geothermal operation by harnessing hot fluids produced from oil and gas production. The coproduced fluids are a byproduct of drilling and production and must currently be disposed properly per government regulations. Rather than disposing of the fluids, the potential exists to generate electricity provided that reservoir temperatures are sufficient.

It has been estimated that approximately 252,180,000 bbl of coproduced water was associated with West Virginia oil and gas production in 2004 (MIT 2006). Further study estimates that 23 MW of electricity could be produced with coproduced fluids at 100°C and 109 MW could be produced with coproduced fluids at 180°C. While no guarantees can be made, further analysis of the bottom hole temperature (BHT) of current oil and gas wells in West Virginia could prove beneficial in energy production.

For the near term, direct use applications, such as preheating water for power plant use, may be the most productive focus. The cost of drilling to depths required to access temperatures necessary for electricity production may prohibit short-term development of an EGS operation in the State. However, as EGS research and development costs are expected to decrease with improved drilling technologies, West Virginia’s EGS potential may prove more economical in the future.

Introduction

Geothermal energy refers to energy produced from the heat found naturally below the Earth's surface. The extent of the geothermal resource can be measured a number of ways, including the gradient and grade. Each measurement will vary dependent on the characteristics of the area where geothermal resources are being examined.

The geothermal gradient is the vertical rate of increase in temperature for a certain unit of depth (MIT 2006). The rate typically falls in the 25 to 30°C per km (14 to 16°F per 1,000 ft) range but can be higher in areas with high-grade geothermal resources (MIT 2006).

Geothermal resources are also measured by grade classifications: non-electrical-, low-, mid- and high-grade (EPRI 2010). Temperature ranges for each classification are provided in Table 1.

Table 1 Geothermal Grade Classification by Temperature

Classification	Temp Min (°C)	Temp Max (°C)	Temp Min (°F)	Temp Max (°F)
Non-electrical-grade	0	100	0	212
Low-grade	100	150	212	300
Mid-grade	150	200	300	400
High-grade	200	None	400	None

Electric Power Research Institute (EPRI), 2010.

Although small-scale[1] geothermal energy can be produced using room temperature heat, commercial production of this energy source requires a temperature of at least 150ºC (INL 2011). Current installed production capacity, estimated as of December 2010, equaled nearly 11,000 MW worldwide (EPRI 2011). The United States accounted for an estimated 3,086 MW (or approximately 29 percent) of that figure.

Two main methods of production are used to harness geothermal energy for electricity generation: conventional and enhanced geothermal systems. Conventional geothermal systems[2] utilize geothermal reservoirs to produce geothermal energy. These reservoirs occur naturally when hot water or steam created by the Earth's heat becomes trapped in a pocket of permeable rock beneath an impermeable rock formation (GEA 2009). In conventional geothermal systems, water is present naturally in the reservoir and aids in transmitting heat for electricity generation.

In contrast, enhanced geothermal systems[3] (EGS) use equipment to replicate the conventional method. EGS requires a fracturing process to break through hot, impermeable rock deep below the Earth's surface. Water is then circulated through the hot rock and hot water or steam is captured to produce energy. As opposed to conventional geothermal systems, water is not naturally present under conditions requiring EGS operations and must instead be pumped into

[1] Small-scale geothermal energy, which includes such options as geothermal heat pumps, involves direct use of the resource. While mentioned briefly, this type of geothermal energy is not directly included in this study.
[2] Conventional geothermal systems are also referred to as "hydrothermal systems."
[3] EGS is also referred to as "engineered geothermal systems" and "hot dry rock (HDR) resources."

the engineered reservoir to generate electricity. Both systems are discussed in further detail in a later section.

Benefits and Issues of Geothermal Systems

Many characteristics of geothermal energy have been examined in recent years to determine the benefit of producing electricity with a geothermal power plant. The environmental impact of this industry appears to be one of the most prevalent. Unlike power plants relying on the use of fossil fuels to operate, geothermal power plants produce no smoke and significantly less toxic emissions (such as nitrous oxide, hydrogen sulfide, sulfur dioxide, particulate matter and carbon dioxide) (GEA 2009). Reduced emissions levels are beneficial to the air quality in these areas.

Geothermal power plants also require less land per gigawatt hour (GWh) compared to those operated using fossil fuels. One 2007 study found that a geothermal facility will use approximately 404 square meters (m^2) per GWh of land to operate (Kagel, Bates and Gawell 2007). By comparison, a coal-run facility will use approximately 3,632[4] m^2 per GWh, solar thermal facilities use 3,561 m^2 per GWh and wind facilities[5] use 1,335 m^2 per GWh.

Power plants using geothermal energy may also deliver economic benefits. A 2007 study published by the Geothermal Energy Association (GEA) estimated that the United States economy can realize a $2.50 output for each $1.00 invested in geothermal energy (Kagel 2006). The same study also exhibited that geothermal power plants require more jobs than a comparable natural gas-fired power plant, therefore increasing employment and benefiting the economy. It was estimated that in 2004 total employment[6] supplied from the geothermal industry totaled nearly 11,500 full-time jobs; approximately 40 percent of this employment figure was attributed to direct employment alone (Kagel 2006).

Utilizing geothermal systems for energy production is not without flaws. Among the most prevalent issues associated with harvesting geothermal energy are impacts on standard of living and the environment. While still rare in many cases, issues associated with geothermal energy production include (EPRI 2011, MIT 2006):

- Ground water use and contamination
- Induced seismicity/subsidence
- Thermal discharge
- Noise
- Safety
- Visual impacts
- Land use.

While other issues listed are fairly straightforward, thermal discharge warrants additional explanation. As with fossil fuel power plants, geothermal power plants emit a certain level of heat into the environment in the form of steam. Because the temperature of steam produced in

[4] The Kagel, Bates and Gawell (2007) study cites two different figures for land use of coal-run facilities: 3632 m^2 per GWh and 3642 m^2 per GWh.
[5] Land use of wind facilities represents the land occupied by wind turbines and service roads only.
[6] Total employment includes direct, indirect and induced employment.

fossil fuel-fired power plants is generally much higher than that produced in geothermal power plants, it is more greatly utilized and therefore more efficient (EPRI 2011). The thermal efficiencies of power plants vary: fossil fuel steam plants range from 32 to 38 percent and nuclear plants range from 30 to 32 percent. By comparison, the thermal efficiency of geothermal power plants ranges from 5 to 17 percent (EPRI 2011).

Geothermal Resources in the United States

According to a 2006 study, EGS could provide an excess of 100 gigawatts (GW) by the mid-2050s with "reasonable" research and development investments[7] (MIT 2006). Many areas of the United States are favorable locations for deep EGS. As the map provided in Appendix A illustrates, the Western United States holds the greatest favorability for geothermal production. However, this does not conclude that other favorable spots in the Eastern United States do not exist.

Recent research funded by Google and conducted by the Southern Methodist University (SMU) Geothermal Laboratory estimated the EGS generation[8] potential by state for the United States. For these calculations, inaccessible lands, such as protected lands, are excluded. A drilling depth of 7 km was also imposed on estimations, with the understanding that additional resources at deeper depths may be recoverable as drilling techniques improve (Google 2011). The calculations, based on a number of studies which approximate EGS resources, resulted in two major factors of generation potential (Beardsmore, et al. 2011, Google 2011, MIT 2006):

1. The **electricity generation potential** demonstrates the estimated electricity potential which could be generated in each state from EGS and other advanced geothermal operations.
2. The **recovery factor**—presented in three tiers: 2, 14 and 20 percent—refers to the percent of total thermal energy within the earth's surface which could be recoverable through geothermal wells to produce electricity. For this factor, resource and well depths range from 3 to 7 km.

According to SMU research, the electricity generation potential in the United States could reach nearly 3,000 GW using EGS and other advanced geothermal technologies (Google 2011). As a result of this research, it was estimated that Texas leads the nation in electricity generation potential with nearly 42 GW possible at 2 percent recovery. Nevada falls closely behind with just over 41 GW of generation potential.

Geothermal Resource Estimates in West Virginia

According to the SMU Geothermal Laboratory research, West Virginia is ranked 19th in electricity generation potential with nearly 4.5 GW at 2 percent recovery (Google 2011). For

[7] The study goes on to estimate that a combined public and private investment of between $800 million and $1 billion would need to be made over a 15 year period to achieve this capacity on the proposed timeline. While the cost is large, MIT (2006) states the estimate is equivalent to the total research and development investments made internationally over the past 30 years and that the cost is, comparatively, cheaper than constructing a new clean-coal power plant.

[8] It is important to note that in most cases the SMU research does not reflect currently generating power plants but rather the potential generation which could be expected from temperature and depth approximations.

comparison, at 14 percent recover, West Virginia is still ranked 19th in electricity generation potential and could be capable of producing an estimated 30.8 GW.

As the map in Appendix A shows, the location of West Virginia's greatest geothermal potential lies in the northeastern part of the State in a portion of the Appalachian Mountain region. SMU research estimates that, while temperatures up to 150°C can be reached around 4.5 km, this area has an approximate temperature of between 150 ºC and 200 ºC at a depth of 6.5 km (Google 2011). Based on geothermal resource classifications and actual drilling depths which may realistically be reached given the confines of current technology, West Virginia's geothermal resource falls into the low- to mid-grade[9] range.

Characteristics of Conventional and Enhanced Geothermal Systems

Three criteria are necessary for the operation of geothermal systems (GEA 2009):

- Heat
- Permeability
- Water.

All three factors are readily available in the geothermal reservoirs where conventional geothermal systems operate. Because naturally occurring water heated by the Earth has been captured in permeable rock below the surface, only drilling for and harnessing the hot water (or steam) is necessary to generate geothermal electricity. This is not the case with EGS.

EGS operations are made more complex because only the heat factor is available naturally in such locations. To produce the hot water necessary to run the turbines, much deeper wells[10] must be drilled and engineered reservoirs must be created by fracturing the impermeable hot rock deep below the Earth's surface. Once the wells[11] are complete, water must be pumped down into the reservoir though the injection well(s) and circulated back to the surface through the production well(s) to turn the turbines. In turn, the turbines operate the generators and electricity is generated. The following sections discuss both systems in further detail.

Conventional Geothermal Systems

Moderate temperature conventional geothermal systems can operate with temperatures at or above 90ºC (194ºF) and generally range to 150ºC (302ºF) (EPRI 2011). Such conditions are typically used in a binary power plant setting where a secondary fluid is used to produce electricity. High temperature conventional geothermal systems typically exceed 150ºC (302ºF)

[9] Non-electrical grade resources, such as direct use geothermal energy, are more accessible. Direct use of geothermal energy requires a cooler resource at temperatures between 100 and 150°C. In West Virginia, it is estimated that this temperature can be reached at 4 to 4.5 km in depth, requiring nearly 2 km less drilling than temperatures for EGS potential (Google 2011).
[10] Wells are also commonly referred to as "bores" or "bore holes."
[11] Wells necessary for geothermal energy production include injection and production wells. Both conventional and enhanced geothermal systems require both types of wells to circulate water from the resource to the power plant and back again.

and are used in a flashed-steam system. In some cases fluid temperatures can reach 400ºC (752ºF) in reservoirs containing substantially permeable hot rock (EPRI 2011).

A typical conventional geothermal system reaches a depth around 3 km (10,000 ft) but can generally range from 200 to 3,500 m (EPRI 2011, MIT 2006). Some systems may require wells at deeper depths to reach the appropriate temperature and conditions, but those instances appear to be rare.

Because the conditions used for conventional geothermal systems occur naturally, natural fluids exist in the permeable rock. These fluids, mostly water containing some amount of dissolved salts, can be in liquid or water vapor state. In some instances, fluids will have to be reinjected into the reservoir to maintain production (MIT 2006).

Enhanced Geothermal Systems

The temperature of the rock is an important aspect of EGS for electricity generation. For successful systems, drilling a well to a depth where the standard minimum temperature[12] is between 150ºC and 200ºC is crucial (MIT 2006). In many western states, such as California and Idaho, temperatures can reach 200ºC at depths between 4.5 and 5.5 km with production potential of approximately 50,000 MW at 14 percent recovery (Google 2011). By comparison, temperatures in West Virginia reach approximately 150ºC at these same depths with production potential ranging between 5,000 and 11,000 MW (Google 2011). While the conditions at these two locations vary, such data shows that geothermal potential in West Virginia does exist.

The depth of EGS wells largely depends on the temperature at certain levels, but generally reach 3 to 10 km (10,000 to 30,000 ft) in depth (MIT 2006). However, it is important to note that the depth of the well does not necessarily determine the most effective site potential. In some areas of the country, a fairly shallow well (perhaps around 3 km) can heat geothermal fluids to a higher temperature than some deeper wells close to the 10 km depth.

Due to the geological circumstances separating conventional and enhanced geothermal systems, very little (if any) water or steam is present in the hot dry rock used with EGS. Because the rock is barely permeable at best, hydraulic fracturing is required to create a permeable reservoir, replicating the natural reservoirs used in conventional geothermal systems, during the construction phase (EPRI 2011). After completion, the injection well pumps fluids[13] into the reservoir and production wells harvest hot fluids and/or steam to run the turbines.

Regions with the most EGS potential tend to exist around active tectonic areas or areas with volcanic activity. Research has been conducted studying both sedimentary and basement rock formations for EGS potential, and a recent study even stated that such resources "are by far the largest and, for the long term, represent the main target for development" (MIT 2006).

[12] The study also notes that temperatures as low as 50ºC can be useful in other geothermal applications, such as geothermal heat pumps.

[13] The type of fluid used can vary. In some instances, supercritical fluids are and can be used both in the hydraulic fracturing process to create the reservoir and later as a geofluid to transfer heat (EPRI 2011).

Types of Geothermal Power Plants

Three types of geothermal power plants are currently used to produce electricity from geothermal resources:

- Dry steam
- Flash steam
- Binary cycle.

Dry Steam Power Plants

Dry steam power plants, also referred to as direct steam or vapor-dominated power plants, are the least common electricity production method used for geothermal energy due to the requirement of naturally occurring steam. First used in Lardarello, Italy, in the early 1900s, dry steam power plants use steam produced from within the Earth—such as that produced by geysers—to operate the turbines which in turn power the generators at the power plant (EERE 2012).

Excess steam (waste heat) is released into the atmosphere through cooling towers while residual geothermal fluids are pumped through the injection well back into the reservoir (EPRI 2011). Because some moisture is lost in the cooling process, additional fluids from surface or ground water or some other source will occasionally have to be injected to replenish the supply. This method of energy production is currently used at The Geysers. Located in California, this dry steam power plant is currently the largest individual source of power generated from geothermal energy in the world (EERE 2012).

Flash Steam Power Plants

Flash steam power plants require fluid temperatures of at least 182°C (360°F) for operation (EERE 2012). Once the fluid is pumped to the surface, it is pressurized and moved to a lower pressure tank where a portion of the fluid will vaporize and operate the turbines at the power plant, much like the dry steam method (EERE 2012).

This type of power plant generally uses single-flash or double-flash technology, meaning simply that the fluid is pressurized once (single-flash) or twice (double-flash) (EPRI 2011). Double-flash power plants capture more available energy from the fluid and the steam generated is generally 18 to 25 percent of the fluid mass, meaning approximately 75 to 82 percent of the original fluid is reinjected after flashing is complete (EPRI 2011). As with dry steam power plants, supplemental fluids will occasionally have to be added to the reservoir.

Binary Cycle Power Plants

Binary cycle power plants use two fluids, a geothermal fluid (or geofluid) and a secondary fluid, to produce electricity from geothermal energy. By definition, geofluids are simply any fluids produced from a geothermal well and may include dissolved solids or noncondensable gases (MIT 2006). Secondary fluids have a lower boiling point and are added to the binary cycle at the surface. Secondary fluids can be organic (such as isobutene, pentane and isopentane) or a refrigerant (such as R134a) (AAPG 2011, EPRI 2011).

The geothermal fluid and the secondary fluid are pumped through a heat exchanger and the secondary fluid is vaporized, much like the flash steam method, to operate the turbines (EERE 2012). Remaining fluids are pumped through the injection well back into the geothermal reservoir. As with the other two power plant systems mentioned, additional fluids will need to be added occasionally to maintain efficiency (EPRI 2011).

Geothermal Operations

Enhanced geothermal operations require different inputs than conventional geothermal systems, including the need for a type of fluid, to operate effectively. Because naturally-occurring water is not found in the impermeable hot dry rock used for EGS operations, a type of fluid must be selected and pumped through the injection well to be heated and circulated. It has been suggested that water is the best choice, as non-aqueous fluids can impose negative impacts, including inferior performance, elevated costs and negative environmental consequences (Tester and Herzog 1990).

Despite suggestions that water (or brine) provides the best option for geothermal fluids, alternative fluids have been examined in recent years. For instance, the Geysers geothermal project in California has begun experimenting with non-traditional fluids to supplement water loss in the geothermal system by pumping treated wastewater from the City of Santa Rosa, California, into the reservoir (EERE 2011, EPRI 2011).

The amount of fluid required for geothermal operations varies dependent on several factors, including but not limited to the type of power plant and the temperature of the fluid. One source estimates between 450 and 600 gallons per minute (GPM) of water was needed to generate 1 MW of electricity from fluid at approximately 150ºC (300ºF) at a closed-loop binary cycle geothermal power plant (EERE 2011). Dropping the fluid temperature to approximately 100ºC (210ºF) would raise the necessary liquid flow to 1,300 to 1,500 GPM to achieve the same output (EERE 2011). The EERE (2011) also approximates that an additional 45 to 75 GPM of clean water would be necessary to cool the fluid if an evaporative cooling system was needed. For comparison, the EGS project in Soultz, France, circulates approximately 1,560 GPM to run the 1.5 MW power plant (EPRI 2011).

Enhanced Geothermal System Development Projects

EGS development has made major strides in recent years with improvements in R&D and increased knowledge of geothermal energy operations. While no commercial scale EGS projects are currently operating in the United States, a few sites exist worldwide (EPRI 2011). In addition to EGS projects, energy conversion (EC) systems have also been put in place to convert prior conventional geothermal systems into EGS operations.

Worldwide EGS Operations

The first major attempt to investigate the potential economic viability of EGS technology began in the 1970s in **Fenton Hill, New Mexico** (EPRI 2011). The purpose of this attempt was to evaluate the potential to create a reservoir deep underground in hot dry rock conditions. The geology of this area is primarily composed of basement hot crystalline rock (Duchane and Brown

2002, EPRI 2011). Although experiments spanned nearly three decades, research at the Fenton Hill site eventually ended.

Similar experiments were conducted in Japan before injection and production wells were established at **Soultz, France**, in the early 2000s. The construction of a 1.5 MW power plant at the Soultz location, put into operation in 2008, further advanced EGS research. This power plant circulates approximately 26 gallons (or 100 liters) of fluid per second (EPRI 2011). Although the upper layer of this area is sedimentary in composition, drilling and fracturing must be completed in a deeper granitic formation at this plant (Ledesert, et al. 1996).

Exploration of geothermal energy has also been implemented at the **Gross Schönbeck** geothermal laboratory in Germany. Developed by GFZ German Research Centre for Geosciences, the Gross Schönbeck site includes two research wells: a former gas exploration well drilled in 1990 and a geothermal well drilled in 2006 (GFZ 2008). Both wells reach approximately 4.5 km and temperatures of 150°C. The region where this site is located is comprised mostly of sediment/sandstone with minor shale and limestone lithology included throughout (Ollinger, et al. 2010).

More recently, **Geodynamics Ltd.** of Australia has made significant strides in advancing the practical use of geothermal resources. EGS wells have been drilled in multiple locations in southeastern Australia up to depths of 5 km (EPRI 2011). It has been estimated that the EGS potential in the Cooper Basin in South Australia holds EGS resource potential equivalent to 50 billion barrels of oil or 10.3 billion tons of coal (EPRI 2011, Geodynamics 2012). The geology of this area consists mostly of granite that is approximately 1 km in thickness (Geodynamics 2012).

Worldwide Energy Conversion Systems

A recent study evaluated 10 binary power plants worldwide to determine their thermal efficiencies and brine inlet (or geofluid) temperatures (MIT 2006). These power plants work as energy conversion systems to utilize coproduced fluids from oil and gas operations to operate hydrothermal systems. The study examined the thermal efficiency[14] of these plants based on the brine inlet temperature (or geofluid temperature) in degrees Celsius. Both the temperature and efficiency for each plant is provided in Table 2.

[14] Thermal efficiency is defined as "the ratio of the net power output to the rate of heat input" and is also referred to as "input thermal power" (MIT 2006).

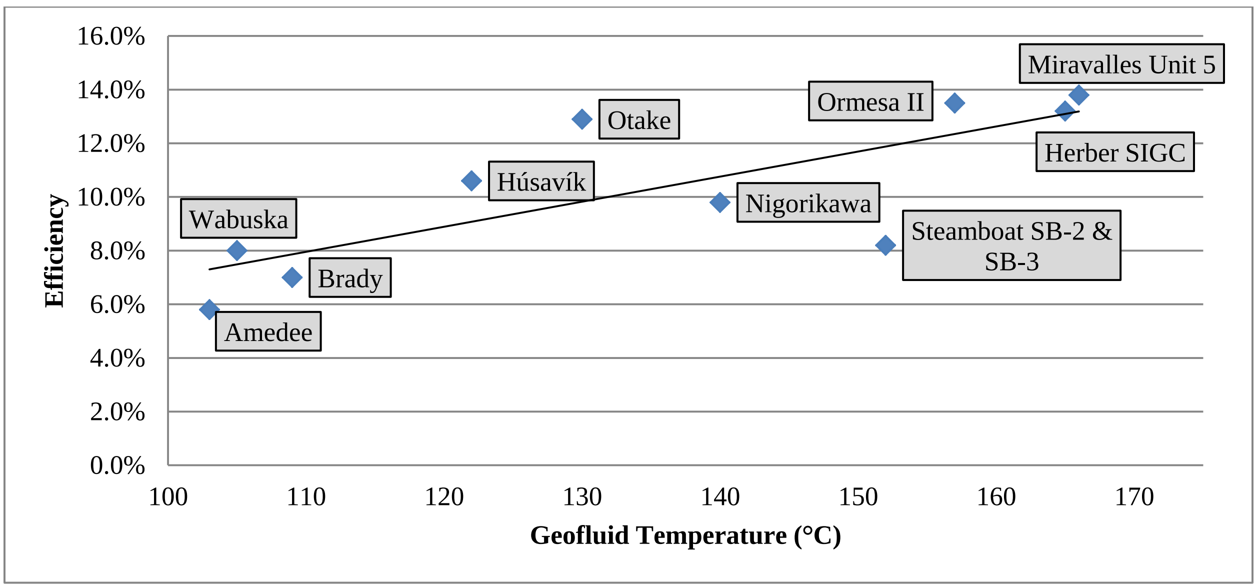
Table 2 Cycle Thermal Efficiencies and Geofluid Temperatures of 10 Binary Power Plants

Plant (Location)	Temperature (°C)	Efficiency
Amedee (California)	103	5.8%
Wabuska (Nevada)	105	8.0%
Brady (Nevada)	109	7.0%
Húsavík (Iceland)	122	10.6%
Otake (Japan)	130	12.9%
Nigorikawa (Japan)	140	9.8%
Steamboat SB-2 & SB-3 (Nevada)	152	8.2%
Ormesa II (California)	157	13.5%
Herber SIGC (California)	165	13.2%
Miravalles Unit 5 (Costa Rica)	166	13.8%

Massachusetts Institute of Technology (MIT), 2006.

The average brine inlet temperature in these 10 power plants is 135°C and average efficiency is 10.3 percent. In general, the study found that the higher the brine inlet temperature the higher the level of thermal efficiency (MIT 2006). A graphical representation of the brine inlet temperature and thermal efficiency correlation is provided in Figure 1.

Figure 1 Relationship between Temperature and Efficiency of 10 Binary Power Plants



Massachusetts Institute of Technology (MIT), 2006.

It has been stated that "binary power plants are a well-established technology for utilizing low- to moderate-temperature geothermal fluids" (MIT 2006). Considering the potential in West Virginia to utilize coproduced fluids from currently producing oil and gas wells in the State, binary power plant systems may be the best geothermal energy production option for West Virginia.

Project Options in West Virginia

Opportunities exist in West Virginia for potential development of unconventional EGS in conjunction with existing oil and gas well sites. An unconventional EGS operation uses such resources as coproduced and geopressured[15] fluids to generate electricity. Emerging potential has been discovered in sedimentary rock where temperatures between 150°C and 200°C are being encountered at depths between 3 and 6 km (MIT 2006). Although further investigation would have to be made into the effectiveness of an unconventional EGS approach in West Virginia, it is plausible that the potential exists given an appropriate combination of experience and site-specific research.

Coproduced fluids occur in oil and gas development because water is produced as a byproduct of drilling and production (MIT 2006). It is estimated than an average of 25 billion barrels of hot water is produced from oil and gas wells in the United States each year (EERE 2010). While the appropriate conditions are not guaranteed with every oil and gas well site, further analysis of bottom hole temperatures (BHT) and site specifics could prove beneficial (Frone and Blackwell 2010).

To use coproduced fluids in geothermal energy production, a site must be suitable to circulate the water—possible in West Virginia's sedimentary rock formations—and reach appropriate temperatures. The system created would be a hybrid mix of EGS and conventional geothermal systems (MIT 2006). Estimates in 2004 stated that a total of approximately 252,180,000 bbl of coprocessed water was associated with oil and gas production in West Virginia (MIT 2006). From this water, it is estimated that 23 MW could be produced at 100°C and 109 MW could be produced at 180°C. Because oil and gas production infrastructure is present in most of West Virginia, as oil and gas well drilling has occurred in most counties, it is possible the State could benefit from coproduced fluids. Further examination would be required to determine the actual potential available.

Much of the technology used to develop EGS in the United States has been modified from oil and gas drilling technologies to accommodate the unique characteristics of geothermal drilling (MIT 2006). Such unique characteristics have caused problems not encountered in current oil and gas drilling technology, including:

- Temperature effects on instrumentation
- Thermal expansion of casing strings
- Drilling hardness
- Lost circulation.

Temperature effects on instrumentation have only begun to be problematic in recent years as the depth of wells drilled has increased. Even in the oil and gas industry, which is beginning to require deeper depths to reach reserves as more shallow deposits are being depleted, higher temperatures found at deeper depths has interfered with the durability of logging equipment and

[15] Due to the lack of existence of a geopressured area in West Virginia, this resource for potential geothermal energy production is omitted. Geopressured resource areas in the continental United States are most prevalent around the Gulf Coast sedimentary basin (MIT 2006).

other electronics used (MIT 2006). To combat such heat-related problems, heat-shield instruments have been developed and are increasingly used in drilling. Among the most sensitive drilling components are the electronics which, until recently, could only tolerate temperatures up to 150°C (300°F); seals and elastometric insulators are slightly more heat tolerate but can be damaged in fluid temperatures exceeding 190°C (370°F) (MIT 2006). Further development of more heat-tolerant drilling components is ongoing.

The **thermal expansion of casing strings** can be detrimental financially as well as overall to the drilling operation as the casing can distort or collapse under higher temperatures than the well casing was previously designed to handle (MIT 2006). A cement sheath is installed from the shoe to the surface of all casing strings to protect from high temperatures (MIT 2006). Currently, wells with maximum temperatures below approximately 260°C (500°F) are fitted with casings which are tolerant of such temperatures.

Because EGS conditions tend to occur in hard rock, in contrast to sedimentary rock formations common with oil and gas wells, the **drilling hardness** adds another difficulty for EGS drilling to overcome. In order to penetrate the often more dense conditions encountered in EGS development, the use of a harder[16] drill, not unlike those used in oil and gas drilling, is necessary (MIT 2006). In addition to requiring a more sturdy drill bit to drill EGS wells, drill bits subjected to drilling EGS wells also tend to wear more quickly as opposed to those used in oil and gas drilling operations. However, in the case of West Virginia, the State's sedimentary rock formations would make drilling hardness less of an issue.

Lost circulation occurs when the flow of drilling fluid is disturbed and circulation stops (MIT 2006). This poses a problem because, once the return flow of the fluid in the annulus[17] has stopped, cuttings inside this outer component of the well can fall downward and clog the drill pipe (MIT 2006). Therefore a constant and sufficient flow of fluids must be maintained to sustain circulation.

As improvements are made in drilling technologies such as those discussed briefly here, the cost of EGS drilling can be expected to decrease.

Project Risks

As with any project, certain risks are associated with EGS operations. These risks can vary greatly and often decrease over time as research and development of a specific site are completed. For instance, risks for a project, including potential flow rates and temperatures of the geothermal resource, will be relatively high at the initial startup. But as the operation is developed—meaning the resource has been correctly identified and the necessary conditions for the project are affirmed—the risk will lower substantially (MIT 2006).

Dependent on temperature, a certain level of flow rates—generally between 50 and 150 kg/s—is required for each production well to ensure that a geothermal operation will be economical (MIT 2006). The flow rate factor is risky because until the drilling is complete and the operation is

[16] A tungsten carbide-based bit is the most commonly used type of drill bit used in geothermal drilling (MIT 2006).
[17] The annulus of a drill pipe is "the space around a pipe in a well bore, the outer wall of which may be the wall of either the bore hole or the casing" (OSHA 2001).

underway, the true flow rates of a particular geothermal project will not be known. Well flow occurs in conventional geothermal systems because of a pressure drop due to the natural permeability in the reservoir. This is an example of transmissivity.[18] Comparable pressure is simulated in an EGS operation through the engineered fractures in the man-made reservoir. High transmissivity is required to achieve high flow rates in an EGS operation (MIT 2006).

Another risk associated with EGS projects regards the interaction of water with minerals in the engineered reservoir, which can change the permeability of the reservoir over time (MIT 2006). This occurs when water (whether surface water, ground water, wastewater, etc.) is heated in the reservoir and then cooled after generating electricity at the power plant. At this point,

> "the circulated water will not be in equilibrium with the minerals in the rock. With time, these minerals may dissolve or minerals dissolved in the water may precipitate, changing the permeability of the rock over time" (MIT 2006).

As a result of this risk, further attention has been paid to developing techniques to control reservoir deterioration and maintain proper permeability.

Economic Models

Economic models provide an important analysis of geothermal operations. Such models can determine approximate costs of geothermal production—from evaluation of site conditions through development and operation of power plants—and suggest optimization of factors for greatest performance. These models rely on a variety of variables, including:

- Reservoir performance
- Drilling and construction costs
- Plant costs
- Energy conversion factors.

A combination of any of the above variables, as well as many others not listed specifically, is used in a number of economic models to evaluate EGS operations from many different perspectives. A few such models are briefly described in this report.

MIT EGS Variable Rate of Return (VRR) Model

The MIT EGS VRR model was used nearly exclusively in the MIT (2006) report to estimate the levelized electricity prices of EGS technology (MIT 2006). Frequently compared to results of the GETEM (discussed in the following subsection), this model considered many conditions including, but not limited to (MIT 2006):

- Financial parameters (i.e. debt interest, equity rate of return)
- System performance (i.e. thermal drawdown rate, well flow rate, number of wells)
- Capital costs (i.e. site exploration, drilling, reservoir stimulation)

[18] Transmissivity is "the ability of a reservoir to allow the flow of fluid through a certain area, generally in the horizontal direction" (MIT 2006).

- Operating and maintenance (O&M) costs.

Most frequently, the MIT EGS VRR model assumed an EGS plant with a quartet configuration, meaning the plant would have three production wells and one injector well (MIT 2006). Further, the EGS plant modeled was assumed to be well developed with a mature flow rate of 80 kg/s. Under these assumptions, it is estimated that the break-even price, in cents per kilowatt hour (¢/kWh), could be 10 ¢/kWh with 25 MW of capacity and could decline to nearly 4 ¢/kWh following installation of approximately 200 MW of capacity as part of a demonstration program with assumed induced technological progress (MIT 2006). Based on these assumptions, the cost per kWh fluctuates thereafter. At 100,000 MW of capacity, it is estimated that the break-even price could rise again to approximately 7 ¢/kWh.

Wellcost Lite Model

The Wellcost Lite Model essentially calculates the cost of drilling wells based on the casing intervals—typically four, five or six intervals with the option to add more intervals as necessary (MIT 2006). Operated using Microsoft Excel, Wellcost Lite considers the following factors for each casing interval to calculate costs:

- Casing design program
- Rate of penetration
- Bit life
- Trouble map.[19]

The **rate of penetration (ROP)** simply refers to the speed that a drill bit cuts through the rock (MIT 2006). While no measures of ROP are specified, it is estimated that problems which lead to slower penetrations rates can increase costs by 15 to 20 percent above conditions that are easier to drill, such as sedimentary rock formations (MIT 2006).

The **bit life** is nearly as important in estimating drilling costs as selecting an appropriate bit type. In the hardest rock formations, bit life will be much more limited than in sedimentary formations. As a result, the life of a drill bit will be drastically decreased if an improper bit is selected for harder drilling conditions. In many cases, the life of a drill bit is limited to 50 hours (MIT 2006).

In addition to well costs, this model calculates the time to drill each interval as well as cost of materials (MIT 2006). A unique feature of this model is that it calculates both time and costs sequentially throughout the intervals.

Geothermal Electric Technology Evaluation Model

The Geothermal Electric Technology Evaluation Model (GETEM) was originally developed for the Geothermal Technology Program of the United States Department of Energy (DOE) (MIT 2006).

[19] Additional information on the definition and use of a trouble map was not available at this time.

Within the GETEM framework, several “documented and expert-interpreted conditions” are considered, including (MIT 2006):

- Reservoir performance
- Drilling and construction costs
- Energy conversion factors
- Competitive financial frameworks.

The result is an estimation of the net levelized energy costs of geothermal electric power at the commercial level (EERE 2012, MIT 2006). The model calculates the impacts of changes in such factors as performance and unit costs from five to 20 years in the future.

EGS Modeling for Windows

The EGS Modeling for Windows software, developed by the MIT Energy Laboratory, provides economic analysis of geothermal systems (MIT 2006). The model considers many parameters, including capital costs, O&M costs, reservoir models and engineering, economic and optimization parameters (MIT n.d.). Updates to the software have occurred as a result of the MIT (2006) report with special emphasis on:

- The cost of drilling
- Plant costs
- Stimulation costs
- Learning-curve analysis.

The learning curve as related to EGS modeling is a concept commonly used in oil and gas drilling (MIT 2006). The basic premise is that, assuming sufficient R&D funding has been provided for commercial scale EGS drilling to commence, a larger amount of start-up costs will allow for a larger portion of the EGS resource to be accessed, which will in turn lead to larger economies of scale and therefore lower average costs per well drilled in the region (MIT 2006). In other words, the more wells drilled the more the cost per well will decrease. According to MIT (2006) the costs associated—including fracturing, stimulation and plant and wellfield O&M costs, as well as plant capital expenditures and exploration success—are influenced by three main factors:

- Technical limit achievable
- Learning potential
- Learning rate.

The learning curve for plant capital costs, staff O&M, wellfield O&M and plant O&M exhibits decreased costs as the installed EGS capacity increases (MIT 2006). Conversely, exploration success increases with increased installed capacity.

Evaluation of Cost Data

The purpose of this section is to evaluate existing EGS technology cost information and, to the extent possible, commute such costs to estimate an EGS operation in West Virginia. The majority of this section reviews estimations calculated by the Massachusetts Institute of Technology (MIT). Some additional cost estimates are derived from the Electric Power Research Institute (EPRI).

Although accurate estimation of well costs for EGS operations is still difficult to determine, the comparison to documented well cost data from the oil and gas industry makes this attempt much more reasonable. Despite abundant similarities, however, it is estimated that "an average completed geothermal well may cost up to 30 [percent] more[20] than [an] oil and gas well for the same depth (up to 3,000 m)" (EPRI 2011). Because EGS wells are highly likely to exceed depths of 3 km to reach a significant heat source, it is plausible to assume the cost for deep wells to be even greater.

Cost Estimation

To evaluate the potential cost of developing geothermal resources in the State of West Virginia, a number of factors must be considered. These include the cost of:

- Drilling
- Capital equipment
- Other related costs.

Cost of Drilling

It is estimated that the cost of drilling the wells necessary to operate a lower-grade EGS project can account for 60 percent of total capital investments—if not more (MIT 2006). Estimating drilling costs in the United States in general—not only in West Virginia—is made more difficult because

> "in recent years, there have been fewer than 100 geothermal wells drilled per year in the United States and very few of them are deeper than 2,800 m (9,000 ft), which provides no direct measure of well costs for deeper EGS targets for the long term" (MIT 2006).

According to the same study, the following factors are just a few of the parameters necessary to make a reasonable estimate of drilling costs alone:

- Drill-site specifics
- Stimulation approaches
- Well diameters and depths
- Well production interval lengths and diameters.

[20] This could be due partially to the fact that geothermal well casings are larger than those required for oil and gas wells (MIT 2006).

Ongoing comparisons of geothermal well costs to wells drilled by the oil and gas industry make such estimations more reasonable. MIT estimated drilling costs of geothermal wells between 1.5 and 10 km. As geothermal wells increase in depth, more casing strings, which provide necessary stability to wells, are required. According to the analysis, it is estimated that a 1.5 km deep EGS well will require 4 casing strings and cost approximately $2.3 million to complete (MIT 2006). By comparison, a 10 km deep EGS well will require 6 casing strings and cost approximately $20 million to complete.

Because geothermal temperatures in West Virginia reach 150°C at about 6 km and 200°C at about 6.5 km, the Wellcost Lite model provides a few estimates comparable to West Virginia's EGS potential. Two cost estimates—one with 5 casing strings and one with 6—were calculated for wells that reach depths of 6 km. With 5 casing strings, each well may cost an estimated $9.7 million (MIT 2006). Adding one more casing string increases the cost of each well to $12.3 million.

Capital Costs

The inclusion of capital costs is imperative when analyzing potential costs of the EGS potential in West Virginia, including an approximation of capital reimbursement and interest charges. The California Energy Commission (CEC) estimated in 2006 that capital costs account for approximately 65 percent[21] of the total cost of geothermal power (MIT 2006).

When considering the cost of a conversion plant that generates electricity from geothermal energy, it has been estimated that such costs can range from $2,300 per kW for resources at around 100°C to $1,500 per kW for resources at around 400°C (MIT 2006).

Other Related Costs

Other costs, such as operation and maintenance (O&M), may not make as large an impact on the overall cost of an EGS operation. However, this is not to say such costs are insignificant. One source estimated that maintenance costs for hydrothermal systems could be double that of fossil fuel power plants due to such factors as corrosion of the well casing (EPRI 2011). As EGS operations can reach much deeper depths, ergo requiring more well casing to accommodate deeper wells, it is plausible that O&M costs for EGS to exceed those estimations.

Based on estimates from the CEC, approximately 35 percent of the total cost of geothermal power is comprised mostly of (MIT 2006):

- Fuel (i.e. water, in the case of geothermal energy)
- Parasitic pumping loads
- Labor and access charges
- Variable costs.

Such factors are essential to the general operation and maintenance of sustaining production in the power plant.

[21] The remaining 35 percent is discussed in the following subsection.

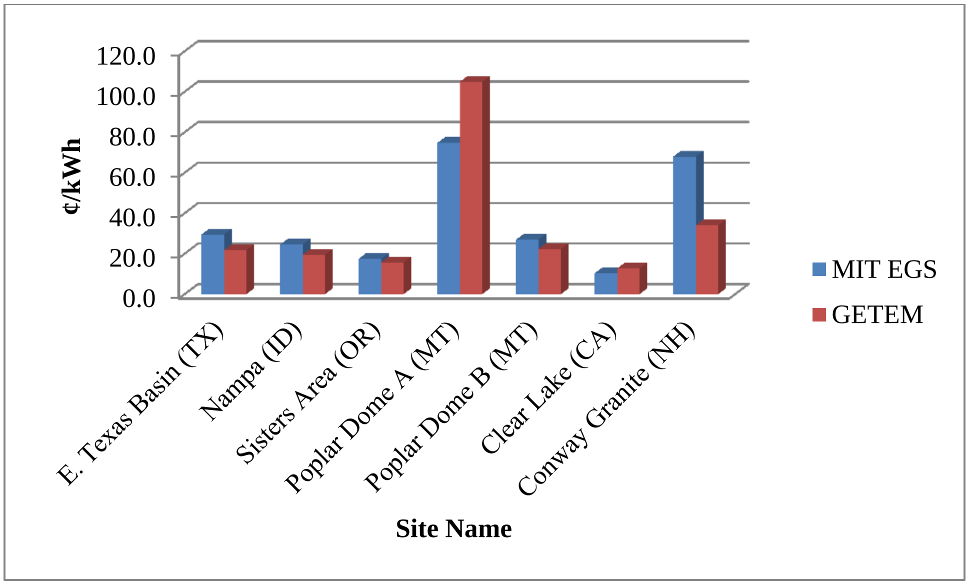
Levelized Energy Cost (LEC)

Estimating costs of EGS operations would not be complete without considering the resulting cost of the electricity. An appropriate measure is the levelized energy cost (LEC). LEC, also referred to as the levelized electricity cost and the levelized cost of electricity (LCOE), is derived from the present value of total building and operating costs of a power plant over its expected economic life, adjusted to remove the impact of inflation (MIT 2006). In essence, the LEC represents the break-even cost of electricity and is a measure frequently used to compare the costs of generating a unit of electricity across various energy sources. Both terms—LCE and LCOE—are used interchangeably in this report.

Currently, the cost of electricity generated from the geothermal systems installed at The Geysers costs between \$0.03 and \$0.035 per kWh (EERE 2011). It is estimated that a new power plant built today would increase that cost by approximately \$0.02 per kWh (EERE 2011).

MIT (2006) examined six potential EGS development sites to calculate the LEC in ¢/kWh using both the MIT EGS and GETEM models. The results found that high-grade EGS sites, such as the Clear Lake site in California, had a much lower[22] LEC than low-grade EGS sites, such as Conway Granite in New Hampshire (MIT 2006). The values estimated between the two models for initial values at 20 kg/s production rate are provided in Figure 2.

Figure 2 Estimated LEC for Six EGS Development Sites at 20 kg/s Production Rate

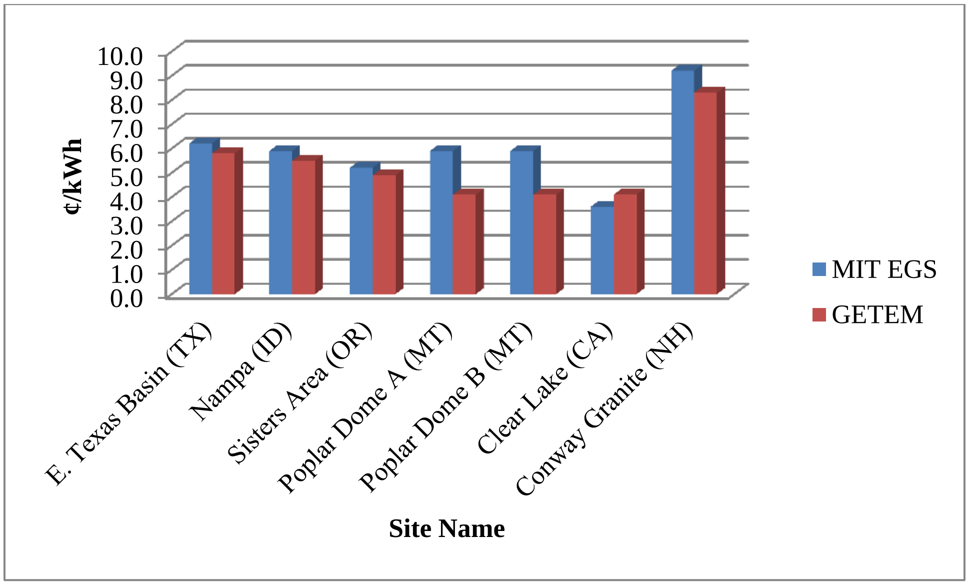


Massachusetts Institute of Technology (MIT), 2006.

Both models were also used to estimate the LEC of the same sites as mature technologies at a production rate of 80 kg/s. These estimated values are provided in Figure 3. Note the drastic decrease in LEC values between initial and mature technology production rates.

[22] MIT EGS estimates were 57.7¢/kWh higher between the two sites; GETEM estimates were 21.3 ¢/kWh higher (MIT 2006).

Figure 3 Estimated LEC for Six EGS Development Sites at 80 kg/s Production Rate

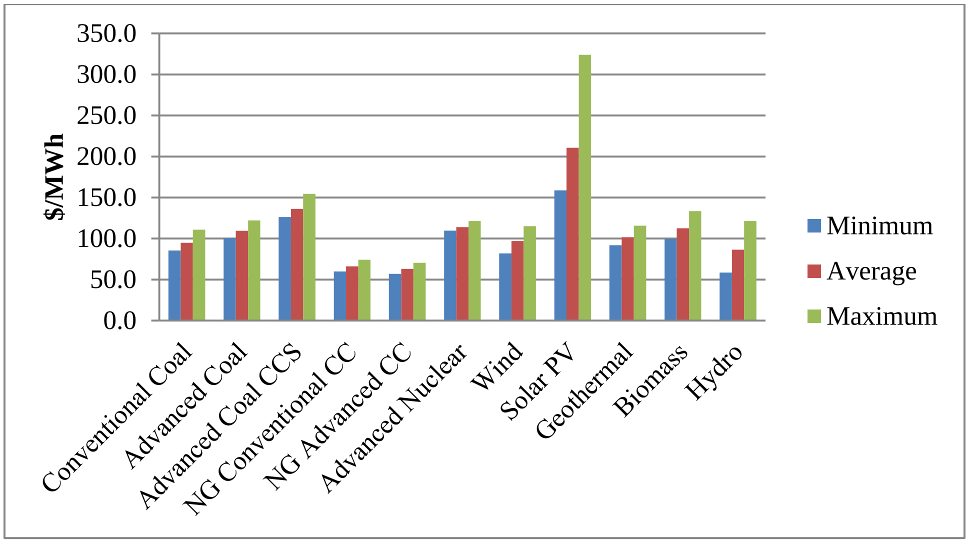


Massachusetts Institute of Technology (MIT), 2006.

As part of the "Annual Energy Outlook 2011" report, the EIA estimated the levelized cost of new generation resources in 2009 $ per MWh. Calculations were made considering a 30 year cost recovery period and a real after tax weighted average cost of capital (WACC) of 7.4 percent (EIA 2010). The results of the levelized cost estimations suggest that conventional[23] geothermal power plants are fairly cost competitive with coal and nuclear power plants, among others (EIA 2010). These estimations are provided in Figure 4.

[23] EGS power plants were not included in this study. The lack of inclusion is obviously not relevant to West Virginia's geothermal potential but is still relevant in analyzing the potential competitiveness of conventional geothermal systems.

Figure 4 Estimated Levelized Cost of New Generation Power Plants



Energy Information Administration (EIA), 2010.

The figures were estimated for new power plants to be brought on line in 2016, as some technologies require long lead times and may not be able to come online before 2016 unless construction had already commenced (EIA 2010). In the graph, "CCS" refers to "carbon control and sequestration," "NG" refers to "natural gas-fired plants" and "CC" refers to "combined cycle." Factors considered when conducting this calculation include (EIA 2010):

- Overnight capital costs
- Fuel costs
- Fixed and variable O&M costs
- Financing costs
- Assumed utilization rate for each plant type.

Excluded from the calculations are state and federal tax incentives, which can change the final cost but were not included here (EIA 2010). The EIA also notes that the estimated costs can vary on a regional basis.

Break-Even Cost of EGS

MIT (2006) provided numerous graphical representations of the levelized break-even cost of electricity as computed using the MIT EGS and GETEM models. Each chart maps out three factors for 100,000 MW of development over the 50 years scenario[24] (MIT 2006):

- Competitive market price
- EGS break-even price
- EGS capacity scenario.

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[24] The hypothetical power plant used in this scenario has an 80 kg/s flow rate, quartet configuration, 3 percent thermal drawdown and 1 km of vertical reservoir spacing (MIT 2006).

As a result of the examination, the EGS break-even price begins much higher (approximately 5 ¢/kWh higher) than the competitive market price of electricity at the five year mark and becomes cheaper than the market price at the 11 year mark (MIT 2006). This occurs mainly because of increasingly higher volumes of capacity installed as part of demonstration programs (MIT 2006).

Additionally, the EGS cost of electricity, which declines through year 16 with only mild fluctuation, begins to increase again through year 50. The highest cost of electricity estimated is 9.99 ¢/kWh, the lowest is 4.4 ¢/kWh and the average is 5.85 ¢/kWh (MIT 2006). Based on MIT predictions, the 11 year mark should occur at approximately 240 MW of capacity assuming commercially mature technology with an 80 kg/s flow rate and a quartet configuration. Here, EGS COE is speculated to be approximately 4.52 ¢/kWh with base-load market at approximately 5.67 ¢/kWh and an EGS deficit of 0 ¢/kWh (MIT 2006). Beyond this point, prices are predicted to remain fairly stable with minimal fluctuation until the 22 year mark (4,000 MW) at which prices begin to rise again.

Cost Sensitivity of EGS LEC

In addition to calculating the LEC, MIT also compared the cost sensitivities of LEC for the six EGS development sites. Each cost sensitivity was determined for flow rates of 20, 40 and 80 kg/s for each site and analyzed eight criteria. These criteria and their respective relationship with the LCOE are (MIT 2006):

- Drilling and completion costs (positive correlation)
- Stimulation cost (remains constant)
- Surface plant capital cost (positive correlation)
- Flow rate/production well (negative correlation)
- Thermal drawdown rate (positive correlation)
- Bond debt interest rate (positive correlation)
- Equity rate of return (positive correlation)
- Percent bond vs. equity debt (negative correlation).

For the purpose of comparison, the high- and low-grade EGS development sites—Clear Lake in California and Conway Granite in New Hampshire, respectively—will be discussed here at flow rates of 20 and 80 kg/s, representing a base case and commercially mature technology. These two sites were used by MIT to illustrate the varying impact of changes in flow rates and other input assumptions on resulting LCOE for different geothermal resource grades. System flow rate is a primary variable affecting a decline in LCOE and distinguishes current EGS technology with future, commercially mature technology.

A notable decline in LCOE at the Clear Lake site results from an increase in system flow rates. At a flow rate of only 20 kg/s, the LCOE is roughly 11.75 ¢/kWh and drops to approximately 8.5 ¢/kWh when the flow rate increases by 40 percent (MIT 2006). In contrast, at an 80 kg/s flow rate the LCOE of is approximately 3.5 ¢/kWh and drops to approximately 3.25 ¢/kWh when flow rates increase by 40 percent (MIT 2006). The other five positive-sloped factors are not expected to change at all or to change very little as the technology matures, and resulting changes to the LCOE are expected to be minimal.

The Conway Granite site is a low-grade resource and differs from the Clear Lake site in that the base case LCOEs are much higher. The LCOE falls from approximately 67.5 ¢/kWh in the base case to approximately 8.25 ¢/kWh in the commercially mature case.

Overall, the LCOE is shown to be most sensitive to five factors (MIT 2006):

- Drilling and completion cost
- Flow rate/production well
- Thermal drawdown rate
- Equity rate of return
- Percent bond vs. equity debt.

Further, because the surface plant accounts for a small portion of total capital costs (relative to drilling costs), the LCOE is shown to be comparatively insensitive to surface plant capital costs for lower-grade EGS resources (MIT 2006). However, the sensitivity appears to increase for higher-grade resources.

It is obvious that the LCOE decreases quite substantially as the flow rate increases regardless of whether the operation is a high- or low-grade EGS development site (MIT 2006). Based on current estimations of the West Virginia EGS potential, it is expected that EGS operations initiated in West Virginia would fall in the low- to mid-grade range and would, therefore, be comparable in theory to the Conway Granite site in New Hampshire.

Total Development Cost

Once projections for drilling, capital and other related development costs are considered, the total cost of establishing an EGS operation can be estimated. However, even with much analysis of cost data, the overall cost of such a facility can still vary.

Estimated Cost of Single- and Double Flash Power Plants

Approximations of single- and double-flash power plants operating at EGS reservoirs can range from $1,773 per kW to $1,894 per kW for single-flash power plants and $1,737 per kW to $1,889 per kW for double-flash power plants with flow rates of 100 kg/s (MIT 2006). In comparison, single- and double-flash plants with flow rates of 1,000 kg/s exhibit barely decreased costs per kW: the lower and upper range costs decreased by an average of $724 per kW and $152 per kW, respectively.

MIT also approximated total EGS plant costs (excluding wells) for a double-flash power plant assuming flow rates of 100 and 1,000 kg/s with temperatures ranging from 150 to 340°C. At a flow rate of 1,000 kg/s, a double-flash power plant would cost between $50 and $260 million between 30 and 265 MW(or $980 to $1,700 per kW) (MIT 2006). By comparison, a double-flash power plant with a flow rate of 100 kg/s would cost between $5.6 and $45.8 million, with expected electricity of between 3 and 26.4 MW (or $1,700 to $1,900 per kW). Assuming a fairly conservative drilling cost of $5 million per well, a double-flash EGS power plant with a quartet configuration and a flow rate of 100 kg/s could cost between $25.6 and $65.8 million.

Estimated Cost of Binary Power Plants

Capital costs for binary cycle power plants have been estimated to range from $3,000 to $8,900 per kW for a 50 MW EGS plant (EPRI 2010). These figures include the cost of the binary power plant ($1,200 to $2,400 per kW) and the cost of wellfield development ($1,800 to $6,500 per kW). In this instance, the wellfield development costs include exploration costs but do not include O&M or "many other factors influencing site-specific capacity expansion decisions" (EPRI 2010).

In addition to current cost estimates, EPRI (2012) also provided a cost target for binary cycle EGS power plants. The target for a 50 MW power plant in the year 2030 was estimated to range from $1,800 to $5,000 per kW, nearly reducing estimated capital costs by half (EPRI 2010).

Flash and Binary Power Plant Cost Estimations—Why the Large Difference?

Comparing the cost estimates for single-/double-flash and binary power plants outright could easily raise some concern. After all, the cost difference in the low ranges between single-/double-flash and binary plants is large, at $1,227 and $1,263 per kW respectively. Because of the significant cost differences, a few incongruences should be noted:

1. The binary power plant estimations (EPRI) are very straightforward in describing costs included. The flash steam power plant estimations (MIT), on the other hand, were not as easily identified.
2. Both power plant cost approximations vary greatly in the modeled production capacity. The binary plant was estimated to produce 50 MW of electricity while the capacity of the flash steam plants ranged from 3 to 26.4 MW with a flow rate of 100 kg/s to 30 to 264 MW with a flow rate of 1,000 kg/s.
3. The flash steam examples projected two flow rates; the binary plant projected none. Because the flow rate of the binary plant is currently unknown, the rate assumed could drastically alter the comparative power of the calculations.
4. The dollar year differed between the two sources. The MIT (2006) study was completed approximately four years earlier than the EPRI (2010) study and reported figures in 2004 dollars. EPRI (2012) reported figures in 2008 dollars. Although the difference of four years may be minimal, the variation is worth noting.

Because the approach used to calculate each estimate was different, it is no surprise that the conclusions varied greatly. As a result, each estimate should be considered individually and not compared to the other.

Assumed Cost Conclusions for EGS in West Virginia

As was stated previously, a binary power plant may be the best option for developing the EGS potential in West Virginia. In addition to capital cost estimates provided above, which admittedly can vary substantially for West Virginia and other areas, the following cost assumptions can be made based on assumptions and estimations of EGS potential in this area:

1. Higher flow rates reduce plant costs. Although potential flow rates for EGS wells are not currently known for West Virginia, further analysis of this potential will provide a better estimation of the impact on costs.

2. Low- to mid-grade EGS locations, such as West Virginia, are still capable of meeting flow requirements but likely at higher costs (MIT 2006). For obvious reasons, EGS operations producing at lower temperatures will incur more costs to develop electricity than a high-grade operation, as less power will be generated during each "loop" of the cycle.

Enhanced Geothermal Systems—A Growing Competitive Market?

Within reason, geothermal resources through EGS operations could be available in most—if not all—locations worldwide. However, the viability of such resource potential is severely limited. As MIT (2006) stated:

> "The ultimate [EGS] resource is virtually infinite, but inaccessible. That is, if it were possible to drill to depths where >350°C heat stores were available, fracture the rock at that depth, and gain access to reservoirs created as a result, then all basement rock on the continent would be a source of EGS" (MIT 2006).

The potential to reach such resources is currently restricted by the limitations in technology and consideration of costs associated with such a feat. That is not to say, however, that progress in research and development and advancements in technology could not one day make such ambitions possible.

As use and implementation of geothermal resources continues to expand, the costs associated with this energy source will decrease—specifically in development, power plant, drilling and stimulation costs—which in turn would increase the ability to access lower-grade EGS resources a deeper depths of 6 km or more (MIT 2006). As R&D advancement continues, geothermal energy—specifically EGS operations—can and very likely will become increasingly more competitive.

Cost-Competitive Advancements in Technology

The improving role of technology in the development, drilling and operation of EGS power plants has been proven recently to pave the way for a more cost-competitive energy source through geothermal production. MIT defined the increase in the cost-competitiveness of EGS technology as occurring in three phases.

1. Use improved drilling and fracturing techniques at existing and/or identified resource-rich sites; this increases the success of the operation, resulting in higher heat yield from exceptional flow rates and improved heat conversion at the power plant (MIT 2006).
2. Expand drilling outside existing geothermal operations to utilize heat resources which were previously inaccessible; an increased supply of electricity to the power grid will result (MIT 2006).
3. Further expand improvements in drilling and fracturing techniques to access geothermal resources nationwide (MIT 2006).

Competitive Levelized Costs

Conventional geothermal energy has already been proven to be cost-competitive with common energy sources such as coal and nuclear power plants, as demonstrated via levelized cost comparisons. With further advancement in technology and drilling, production and utilization techniques, the levelized cost of conventional geothermal systems could decrease. Furthermore, as improvements continue in these areas, the competitiveness of EGS potential could also improve substantially.

Conclusions

The use of geothermal energy produced through conventional and enhanced geothermal systems has drawn increasing attention in recent years. Although costs are currently high[25] and the prevalence of installed and operating EGS power plants is still somewhat limited, great potential for advancement of enhanced geothermal systems still exists. It has been projected, through in-depth calculations, that the overall costs associated with EGS development can decrease over time as technology and techniques improve.

In the near term, it may be most productive to focus efforts on direct use, non-electricity applications (i.e. for a district or building heating system and pre-heating water for use in a power plant), as this type of system can operate at lower temperatures (Fox, Sutter and Tester 2011, Lund 2011). Due to the high projected costs of drilling to depths required to access the EGS resource with temperatures exceeding 150°C in West Virginia, development of the lower-temperature resources may currently be more economical.

While the true EGS potential in West Virginia is still unknown, several factors—analyzed in larger studies and examined in this report—appear very promising for the future. With an appropriate amount of funding, more conclusive evidence of this potential can be unearthed through research and eventual development. After all, the ability of an EGS facility to provide consistent, base-load power cannot be ignored. As fossil fuel resources are exhausted or become too expensive to expand, EGS could assume a leading role in providing consistent—and affordable—renewable base-load power to the grid.

[25] In addition to the investment estimations for the 100 GW installed geothermal capacity in 50 years prediction, MIT estimates that investments between $300 and $400 million would need to be made in a 15 year period "to make early-generation EGS power plant installations competitive in evolving U.S. electricity supply markets" (MIT 2006).

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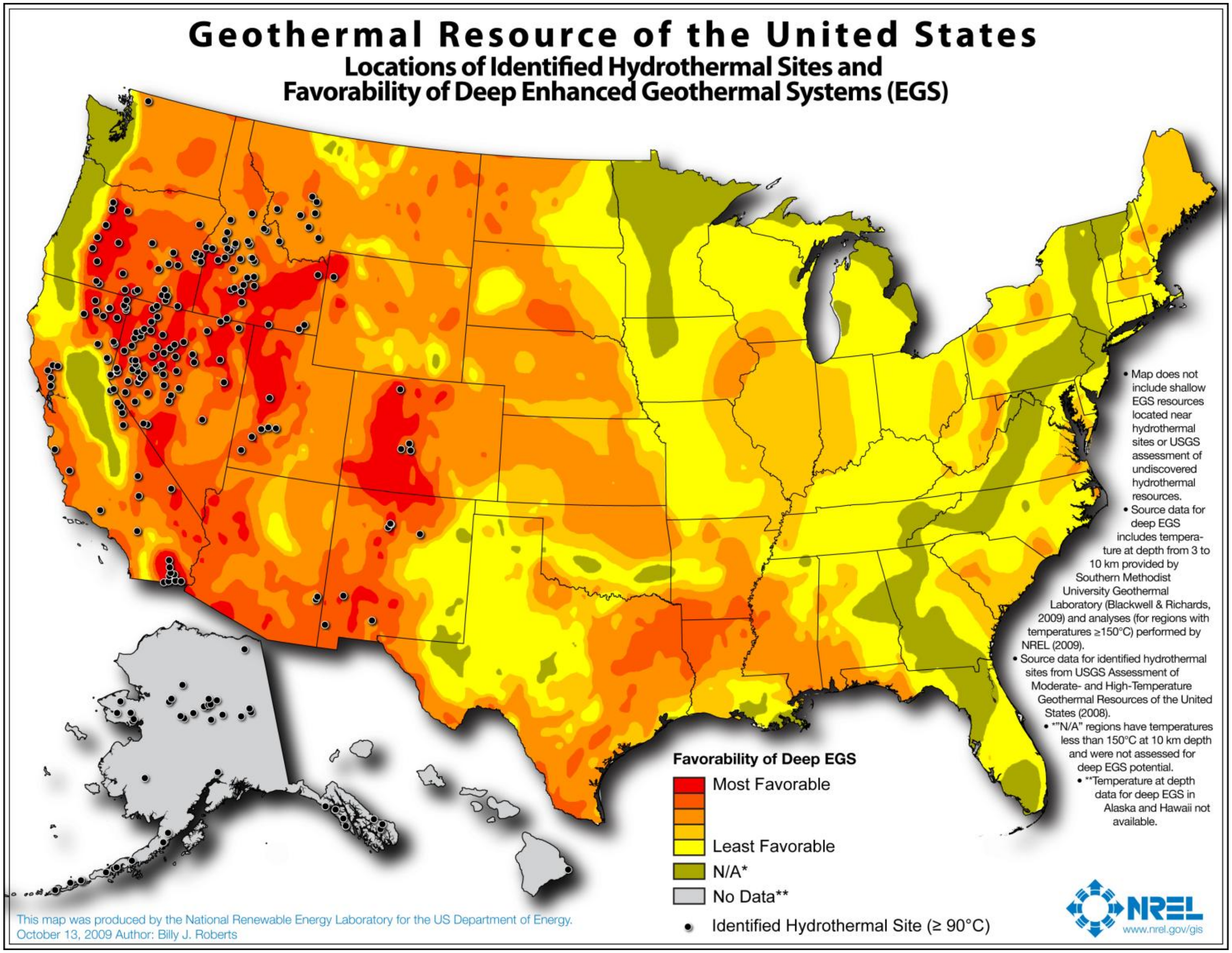
Appendix A United States Geothermal Resource Map



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