Geologic Thermal Energy Storage of Solar Heat to Provide a Source of Dispatchable Renewable Power and Seasonal Energy Storage Capacity

Dan Wendt[1], Hai Huang[1], Guangdong Zhu[2], Prashant Sharan[2], Josh McTigue[2], Kevin Kitz[3], Sid Green[4] and John McLennan[5]

[1] Idaho National Laboratory

[2] National Renewable Energy Laboratory

[3] Kitzworks, LLC

[4] Enhanced Production, Inc.

[5] University of Utah

Keywords

geologic thermal energy storage; subsurface thermal energy storage; reservoir thermal energy storage; TES; earth battery; sedimentary basins; solar power; concentrated solar power; solar thermal power; dispatchable power; power cycle analysis; organic Rankine cycle; flash steam cycle; five-spot well configuration; push-pull well operation

ABSTRACT

This paper concludes that there is a cost-effective strategy for seasonal storage of heat that will provide firm, but dispatchable, electrical generating capacity in times when other renewable energy is not available to meet demand. Deployment of the technology appears to require no new technology, but instead combines solar, geothermal, and conventional oil and gas drilling technologies in a novel way. The study basis is the use of sedimentary geologic formations as a medium for thermal energy storage (TES), specifically for heat collected in concentrating solar collectors.

The study identifies methodologies that could be used to transport this heat into and out of the subsurface in order to produce dispatchable electrical power, and reports on initial optimization results. The GeoTES system (heat input, storage, heat recovery, and heat to electric conversion) described in this analysis has the potential to provide a unique pathway for increasing the grid penetration of renewable energy in large blocks of power and across many states and regions.

Further, the system can be used both to meet the nation's flexible energy needs while also improving grid stability and reliability.

The present study evaluated the use of a large number of dedicated wells to store and recover the heat, essentially creating a synthetic geothermal reservoir. The use of sedimentary geology allow the wells to be drilled at low cost. Dedicated hot and cold wells are used, arranged in a five-spot well pattern with each hot or cold well surrounded at an appropriate distance by the opposite type of well. In large numbers this becomes alternating rows of hot and cold wells. Each hot and cold well is operated using a push-pull strategy. This configuration provides the ability to immediately recover stored hot fluid from a GeoTES reservoir, or to store the heat over many months for recovery at low loss when needed. This is a practical approach for managing the system's fluid inventory, and reducing parasitic load. The production and injection power requirements are reduced because the rows of wells operating in "push" mode provide help to the wells operating in "pull" mode, and vice-versa. Initial charging of a GeoTES system increases the heat recovery temperature. Increasing the duration of the charging period decreases the magnitude of the temperature fluctuations that occur following prolonged system operation.

Because of direct contact of the heated water with the reservoir formation, the production of both hot water and steam from the TES, and the temperature ranges of the recovered fluid (190 – 230°C or 375 – 445°F), conventional geothermal power cycles were used to convert the stored heat to electricity. A power cycle configuration for the GeoTES system was selected following a screening study of a number of flash, and flash/binary hybrid options. This analysis concluded that, of the configurations evaluated, a dual-stage flash steam cycle provides the lowest capital costs per unit net power generation with an acceptable hot brine inlet fluid flow rate. The evaluation included the power plant cost estimate, the cost and number of wells and the associated parasitic loads.

Annual power generation performance was simulated to evaluate capacity factor and LCOE. The LCOE calculated for the inherently high capacity GeoTES system was $0.13/kWhe. This value was calculated for the case where the solar thermal collector was sized in such a way that the solar collectors permitted an annual power plant capacity factor of up to 97%. The power cycle was able to provide power to the grid every night of the year, and flexible base-load power during the winter, if needed. This LCOE value compares favorably with reported values for solar photovoltaic plus battery energy storage (PV+BES) systems in the open literature, i.e. $0.148/kWhe for a PV+BES system with 4 hours of electrochemical battery energy storage capacity (McTigue et al, 2018a; McTigue et al, 2018b). Addition of battery energy storage with more hours of storage would further increase PV+BES system LCOE and increase the separation between GeoTES and PV+BES. A GeoTES system would therefore provide superior economics for high capacity and long duration solar energy storage.

1. Introduction

Variable renewable energy sources such as wind and solar photovoltaic (PV) have become increasingly prevalent sources of electrical power generation due to consistent decreases in the costs of these technologies. Although the costs of wind and solar PV can compete with conventional sources of power generation such as natural gas and coal on a $/MWh basis, the variable nature of wind and solar PV add costs to the electrical grid especially as market penetration becomes large. These technologies also currently require fossil fuel backing due to the fact that they cannot always provide the power generation required by the electrical markets that they serve. Batteries remain too expensive to provide full annual or seasonal backup to these variable sources. The objective of the research is not to displace the low-cost PV and wind generators, but instead to displace the fossil fuel and electrochemical backing of these technologies.

Electrochemical batteries are a commercially available energy storage technology that could be used to store electricity produced by variable sources and then produce electricity when demand is high. However, electrochemical batteries have high capital costs, and ongoing replacement capital and maintenance costs. Because of this and other factors, they are not considered practical for providing high capacity energy storage that could be used to store energy over longer time durations such as days, weeks, or months. The objective of the research is to provide long-duration storage where other options are not viable.

The subsurface can be heated and used as a medium for thermal energy storage (TES). The present study evaluates the use of the subsurface as a medium for the storage of heat collected in concentrated solar collectors and identifies technologies that could be used to transport this heat into and out of the subsurface as well as to reliably produce on-demand electrical power using the recovered heat. Use of subsurface energy storage would provide a unique pathway for increasing the renewable energy generation that can be used to meet the nation's around-the-clock energy needs while maintaining the levels of grid stability and reliability that are absolutely essential in today's computer-driven economy.

Sedimentary systems have characteristics that appear well suited for hosting a geologic thermal energy storage (GeoTES) system. Figure 1 illustrates the large areas of the continental US where sedimentary systems exist (Porro et al., 2012). The prevalence of sedimentary systems suggests that development of GeoTES technology could provide energy storage capacity on a magnitude sufficient to transform US energy markets.

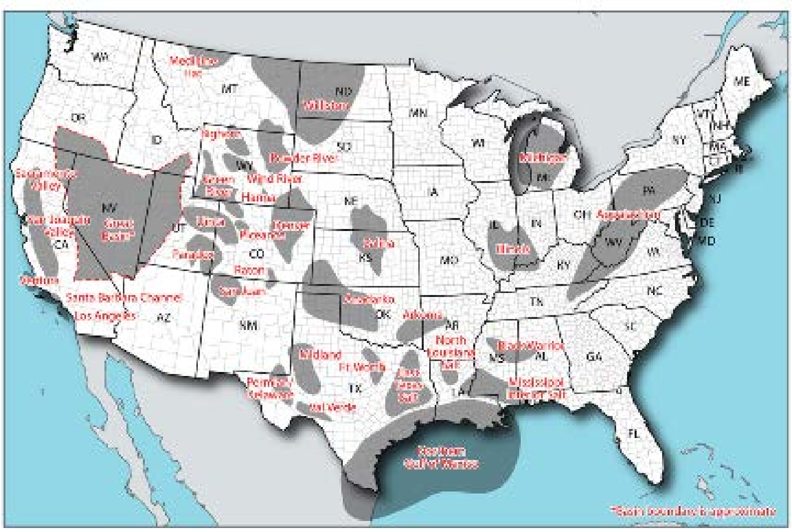

Figure 1. The shaded areas indicate the location of sedimentary formations in the United States (Porro et al., 2012).

2. GeoTES System Description

Heat Source

Any low-cost heat source could be used for a GeoTES system such as the one described here. This includes waste heat from fossil fuel combustion or unneeded nuclear power plant heat. For this study, the use of solar thermal energy is investigated.

Parabolic trough solar collectors are specified as the technology used to collect solar energy for subsequent storage and power generation using a thermoelectric power cycle. However, this choice of solar energy collector is not critical, and other forms of solar thermal collectors are also viable. Parabolic trough solar collectors focus solar radiation onto a receiver tube filled with a circulating heat transfer fluid (HTF). Heat transfer fluids such as DowTherm™ and Therminol® are commonly used for concentrated solar applications. As the HTF flows through the solar collector receivers, it is heated to a high temperature. In conventional concentrated solar power (CSP) applications the high-temperature HTF transfers heat to the power cycle via a series of heat exchangers (i.e., an economizer, vaporizer, and superheater in a conventional steam Rankine cycle based CSP plant). In the GeoTES system, heat exchangers will be used to transfer heat from the hot HTF to pressurized brine from the sedimentary formation. The hot brine will then be injected into the subsurface where it will be stored. The hot brine will be recovered and used to provide heat input to the GeoTES system's thermoelectric power plant during periods of high electricity demand.

Solar heat can be collected at temperatures of 400°C and greater. However, for the GeoTES application 250°C was selected as the baseline heat storage temperature. Although thermoelectric power plant efficiency would be greater for a higher heat recovery temperature, 250°C was selected as an intermediate value. This temperature is expected to provide acceptable power plant efficiency while minimizing potential operational issues and also avoiding the requirement for deep wells for storing liquid phase brine in formations with high hydrostatic pressure.

Reservoir Configuration

The reservoir configuration considered consists of sedimentary basins confined by cap rock and base rock layers. The cap rock and base rock permeabilities are significantly lower than the thermal reservoir's permeability. Consequently, movement of fluid is confined to the reservoir zone. However, the cap and base rock can absorb/transmit a small percentage of the overall injected energy through conduction.

In the analyses carried out, the vertical permeability is assumed to be one tenth that of the horizontal permeability. This permeability anisotropy approximates the effect of different permeabilities in characteristically layered sedimentary environments. Injected fluid would preferentially flow horizontally with less tendency to flow in the vertical direction across lower permeability interbeds.

To use liquid phase water to store high-temperature solar heat in the subsurface, the formation must be at a depth where the hydrostatic pressure is sufficient to maintain the water in the liquid phase. To maintain water heated to 250°C (482°F) in the liquid phase, the fluid must be maintained at a pressure of 4 MPa (580 psi) or greater. As the hot fluid travels down the wellbore, the hydraulic head of the fluid above will cause the pressure to increase. Therefore, 4

MPa is the minimum pressure that must be maintained in the brine exiting the solar HTF / brine heat exchanger.

A reservoir depth of 1,220 meters (4,000 feet) was selected for use in subsurface simulations, as a simplifying assumption. This reservoir depth easily provides the hydrostatic pressure required to maintain liquid phase brine at a temperature of 250°C. This depth is also deep enough to avoid aquifers and to mitigate the risk of hydraulic fracturing during injection. For the injection rate selected, the initial bottomhole injection pressure for the 1,220 meters depth reservoir evaluated in the GeoTES system analysis is 12 MPa (1740 psi). Figure 2 indicates that a bottomhole injection pressure of 12 MPa at a temperature of 250°C is below a rule-of-thumb threshold in situ vertical stress gradient of 0.6 psi/ft at which hydraulic fracturing of the injection well might occur. When a particular area is studied for deployment, there is considerable potential to use shallower formations and lower-cost wells.

Other reservoir design parameters include an initial, undisturbed reservoir temperature of 50°C (122°F), and it is assumed that there is no regional flow in the formation. The formation thickness is specified as 100 meters (328 feet) with an injection interval equal to the formation thickness. Reservoir horizontal permeability is specified as 1.0 x 10^{-13} meters squared (100 milliDarcies).

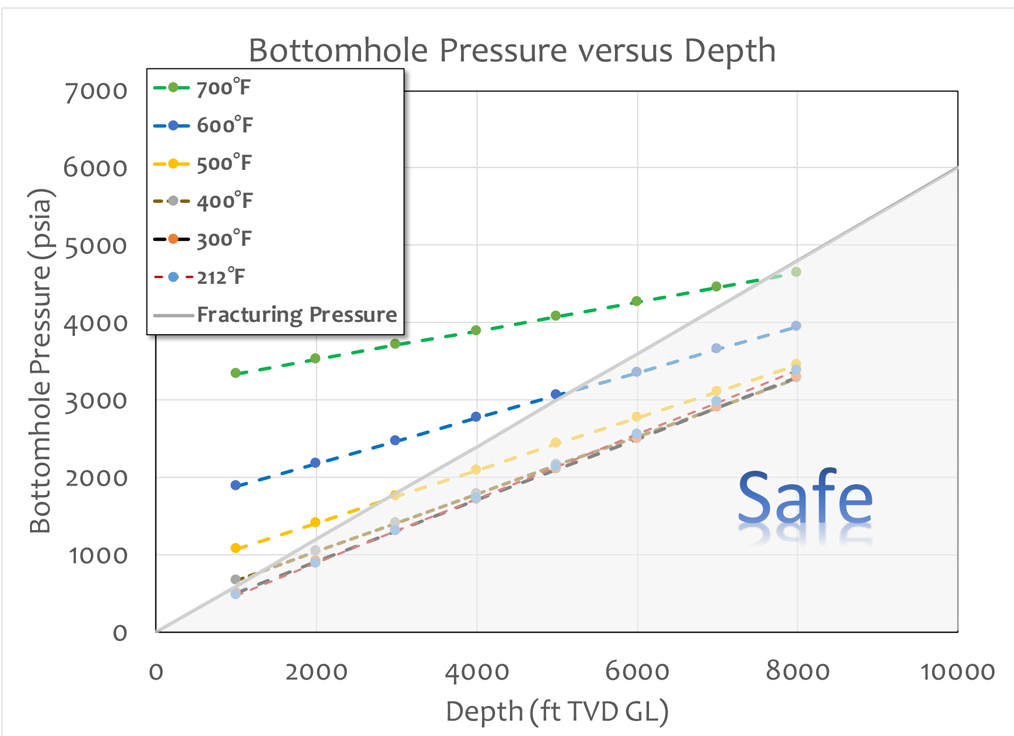

Figure 2. Bottomhole injection pressure at various depths and temperatures. The grey line indicates in situ total stress at 0.6 psi/ft. If pressures are less than this, immediate hydraulic fracturing will not occur.

Well configuration and operation

The GeoTES is a synthetic geothermal reservoir in which the well configuration determines how heat is added and recovered from the system, and consequently where the heat is stored in situ. The well configuration will also dictate the method by which the brine must be circulated through the formation. This configuration will determine thermal characteristics (i.e., location of the thermal front) as well as the pumping requirements to circulate and maintain fluid in the desired phase.

This analysis evaluated a 5-spot well configuration in which the center wells are designated as “hot wells” and the corner wells are designated as “cold wells” (Figure 3). The “hot wells” are operated in a push-pull operating mode and are used to store heat obtained from the solar collectors. Push-pull is sometimes also known as huff-and-puff or injection-production cycling. The “cold wells” are operated in a push-pull configuration that is complementary to the hot well operation. When the cold wells “push” (inject), the hot wells “pull” (produce) and vice versa. The so-called cold wells are used to store cool brine from the time it exits the power plant to the time it is reheated. This operating strategy allows the fluid injection to provide pressure support for the fluid production in both the heat storage and heat recovery operating modes. Since fluid is always returned to the formation, use of “hot” and “cold” wells eliminates the need to store brine in a surface vessel/reservoir between operating cycles. Storing brine in an open surface reservoir would expose it to evaporation, oxygen, and biological contaminants that would likely result in significant operational issues.

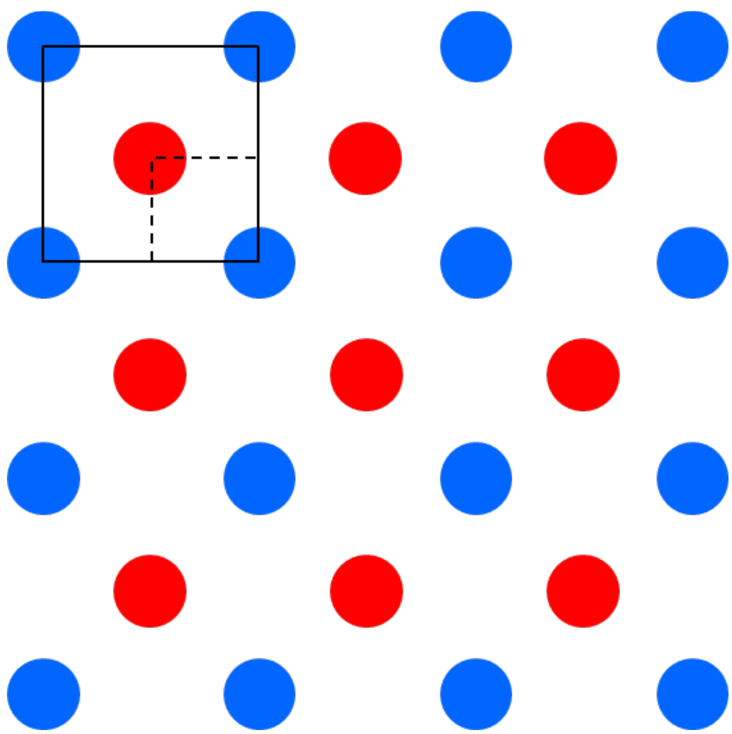

Figure 3. This shows a repeated five-spot well field configuration: Red “hot” wells denote where solar-heated hot water is injected and produced later; blue “cold” wells are where reservoir fluid is produced for solar heating and cooled water from the power generation cycle is injected back to the reservoir. The solid square represents a single five-spot “tile” in which there is a net total of one hot well and one cold well.

Figure 4 shows a schematic for a GeoTES heat storage system. The main components include the power block, solar collectors, and the GeoTES reservoir. The solar field uses parabolic trough collectors with oil (Therminol VP-1) as the heat transfer fluid. The GeoTES working fluid is water. During the charging cycle, the oil gets heated in the parabolic trough collectors and is sent to the heat exchanger to heat the brine pumped from the cold wells to the hot wells. The cooled oil is sent back to the parabolic trough collector. During the discharging cycle, heated brine from the hot wells is extracted and sent to the power block for producing power. The cooled brine exiting the power block is sent to the cold wells.

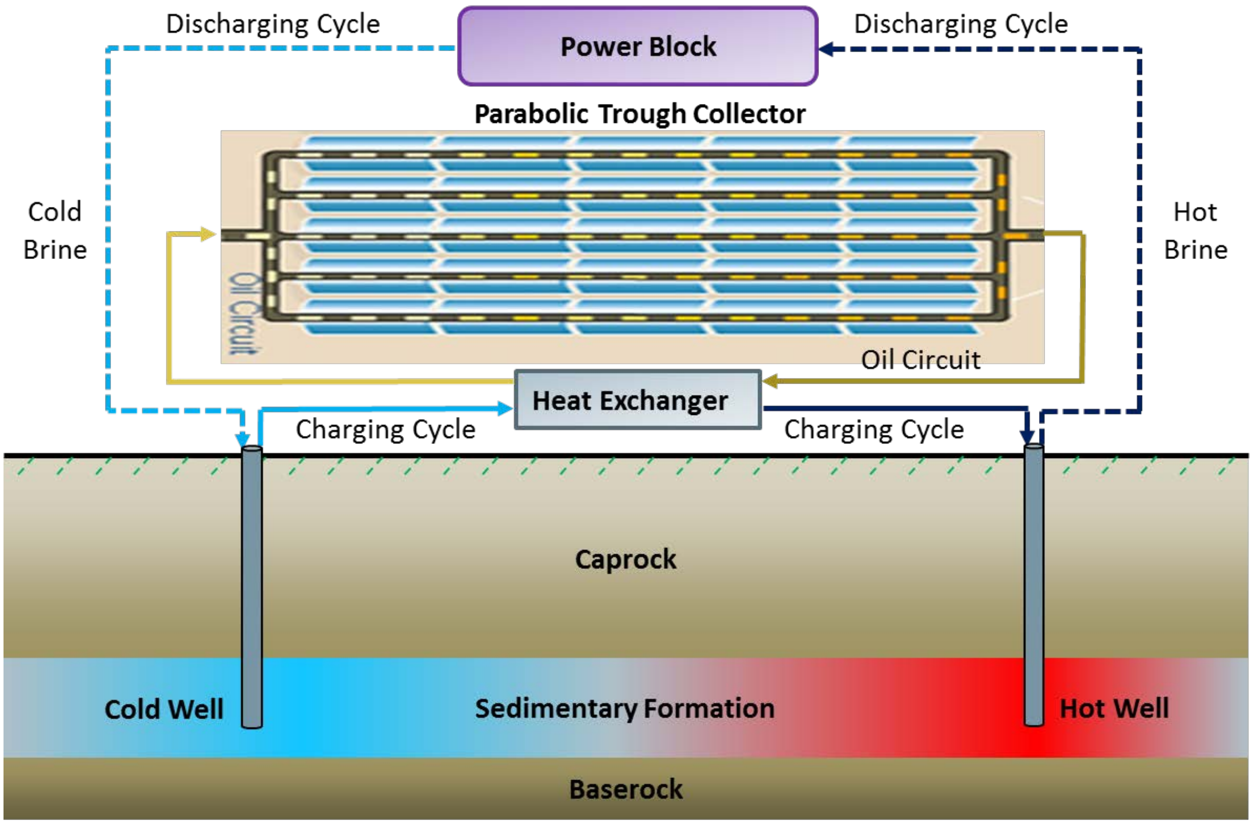

Figure 4: Schematic for the Geologic Thermal Energy Storage (Geo TES), solar collectors, and power block.

Figure 5 is a diagram of the system operating principle. In this figure, orange circles designate operations that are required to accomplish GeoTES “charging” while black circles designate operations required for GeoTES “discharging.”

The fluid injection and production strategy must be compatible with the capabilities and limitations of commercially available pumps. Use of conventional injection pump technology is acceptable for the GeoTES application since the required pump can pressurize the water before it has been heated (pressurized cold fluid will be sent to the solar field HX for heating before injection). Commercially available production pumps are not capable of operating at reservoir temperatures of or even near 250°C. Therefore, the hot wells will be operated under artesian conditions, i.e., the wellhead pressure will be reduced to allow the fluid to be produced from the formation by "flashing" or boiling as it comes up the wellbore, resulting in a mix of steam and water at the surface at a lower temperature than 250°C.

In the reservoir modeling phase, the study assumed a daily injection-pumping cycle scenario in which solar-heated water is injected into the reservoir down the hot wells (red in Figure 3**)** for 8 hours at an injection rate of 40 kg/s and at 250°C. During this solar-heated water injection stage, the same volume of "cold" reservoir water is pumping out from cold wells (blue in Figure 3) at the same rate. This "cold" reservoir water will be solar-heated. After 8 hours of injection of solar heated water, a 10-hour heat production stage starts by pumping out the previously injected hot water from "hot" wells at a rate of 32 kg/s. During this heat production stage, the same amount of "exhausted" water (assumed 70°C temperature) is injected back to the reservoir into the cold wells. After this heat-production stage, all wells are shut in and the system is idle for 6 hours before the next daily cycles starts. Although 8 hours of continuous heat recovery was modeled, this "discharge" would be fully dispatchable and indifferent to a lower rate of production over the full 14 hours, or multiple high and low discharge periods. The charging cycle in which heat is added to the reservoir is idealized at 8 hours every day.

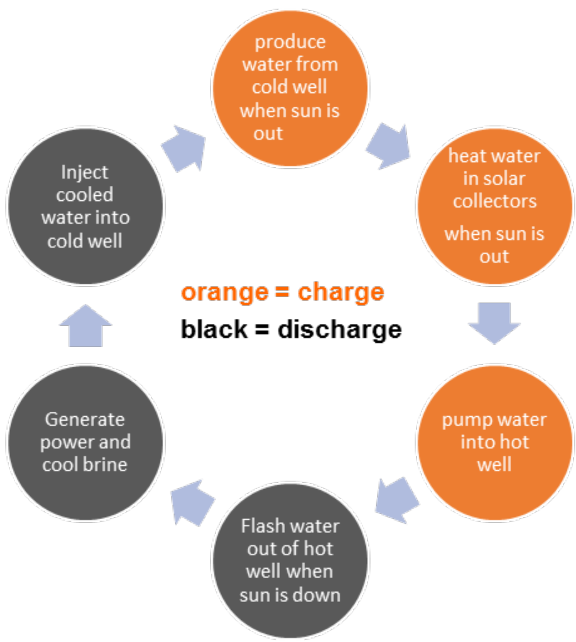

Figure 5. GeoTES system operation

Power cycle

A power cycle screening study was completed using proven geothermal power plant technologies and methods in which the following configurations were evaluated using a brine inlet temperature corresponding to the GeoTES brine recovery temperature at the surface after flashing:

- Single-stage flash steam cycle
- Single-stage flash steam cycle + simple ORC

- Single-stage flash steam cycle + ORC with recuperator
- Single-stage flash steam cycle + ORC with turbine inlet dryness of less than 100% in order to exit the turbine with lower superheat and no recuperator.
- Two-stage flash steam cycle

The screening study determined that the two-stage flash steam power cycle results in the lowest capital cost per unit of net power generation. Additionally, the two-stage flash steam cycle requires a mass flow rate of brine less than the single-flash steam cycle and comparable to the configurations that include an ORC bottoming cycle (per unit net power generation). Therefore, for the present study, the two-stage flash steam cycle is considered.

Figure 6 shows the schematic for the two-stage flash steam cycle. The hot water from the hot well is extracted and is flashed in the flash vessel at 210°C. This results in the production of vapor and saturated water at 210°C. The saturated water coming from the first flash vessel is flashed in the second flash vessel to produce additional vapor. The vapor produced in the flash vessels is used to run the turbines and generate electricity. The vapor exiting the steam turbines is condensed in the air cooler and pressurized to 1 MPa (10 bars) and mixed with the saturated water exiting the second flash vessel. The mixed water is then pressurized to 5 MPa (50 bars) and injected into the cold well.

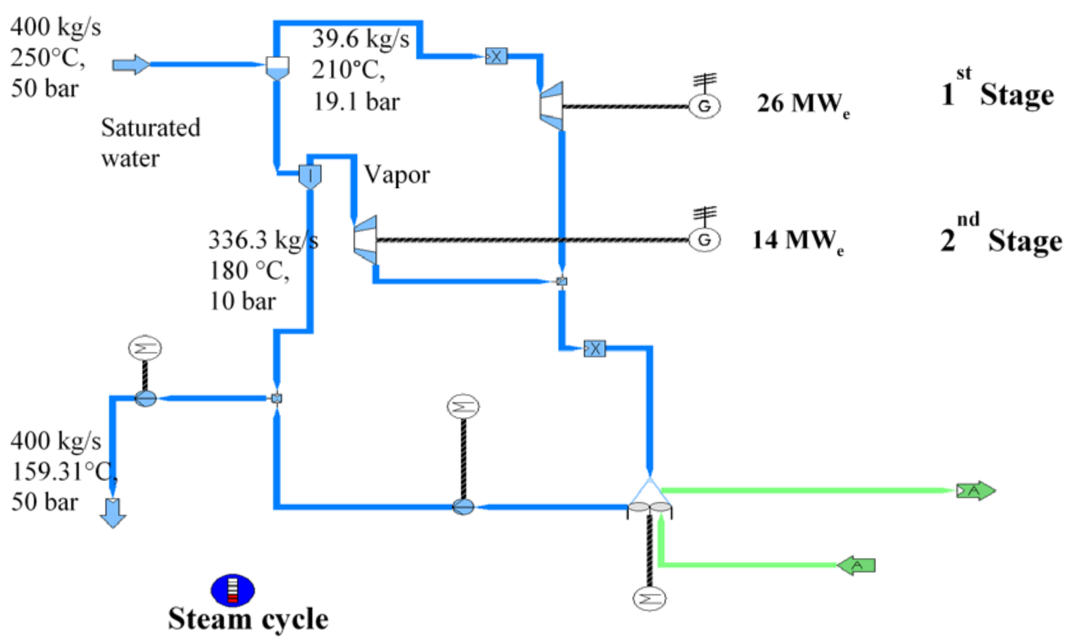

Figure 6: Schematic of double stage flash steam cycle

The power plant will utilize dry cooling technology to minimize system makeup water requirements and/or prevent pressure declines associated with depletion of the GeoTES fluid. The dry cooling technology specified for use with the GeoTES flash plant includes the use of a proven geothermal direct contact condenser (DCC) paired with an air-cooled water cooler

(ACWC). The condensate will be cooled in the ACWC to provide the DCC cold liquid feed stream. This condenser design will allow air cooling technology to be used to condense the steam obtained from the Geo TES brine without non-condensable gas buildup as would occur in traditional steam power plant ACCs. Details of the DCC/ACWC condenser are included in Figure 7.

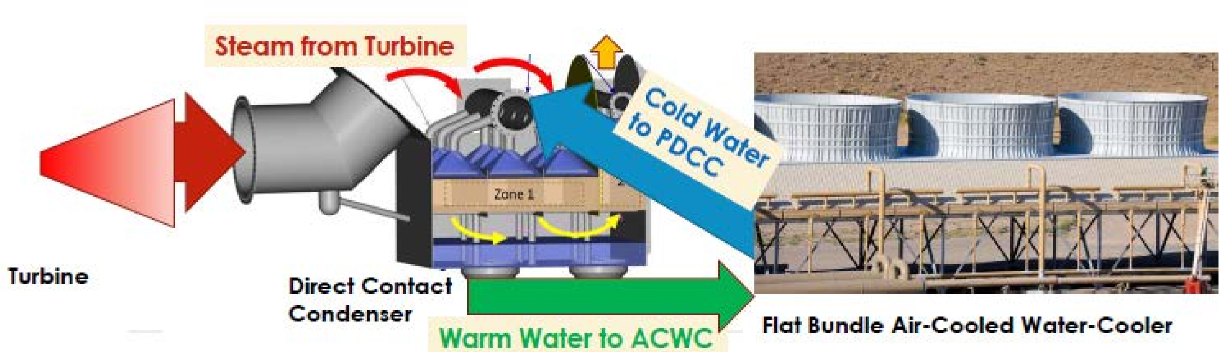

Figure 7. DCC/ACWC dry cooling technology for steam cycles: A direct contact condenser (DCC) coupled to an air-cooled water chiller (ACWC) allows dry cooling of steam cycles, including those that utilize geothermal brines containing non-condensable gases (Kitz, 2018)

3. Subsurface heat storage and recovery

Injection of solar-heated water and the follow on heat storage, conductive heat loss and recovered temperature of produced water were simulated using a multiphysics finite element code, FALCON, developed at INL (Podgorney et al., 2010).

As shown in Figure 8, a generic reservoir of 100-meter thickness, with low-permeability caprock and underburden layers, at a vertical depth of 1200 meters (4,000 ft) TVD GL were chosen for simulations. Table 1 summarizes the flow and transport properties of the reservoir.

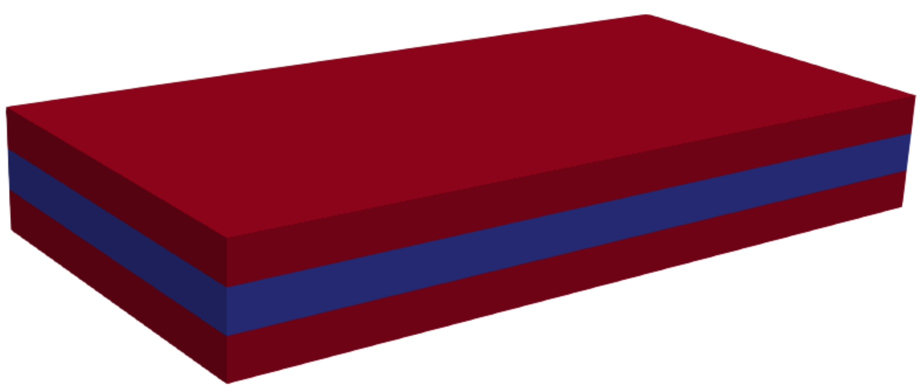

Figure 8. Conceptual 3-layer reservoir model: top and bottom layers – low-permeability barriers; middle zone – injection and storage formation

Table 1. Reservoir properties used in the simulations

Layer	Thickness (m)	Permeability (m^2)	Porosity	Rock Density (kg/m^3)	Rock Specific Heat (J/kg K)	Thermal Conductivity (W/m^2 K)
Caprock and Bedrock	100	Isotropic, 1.0e-19 (i.e., 100 nanoDarcy)	0.025	2500	770	1.05
Injection Formation	100	Horizontal: 1.0e-13 (i.e., 100 millidarcy) Vertical: 1.0e-14 (i.e., 10 millidarcy)	0.15	2000	930	2.50

The initial reservoir temperature at the middle of the injection formation was chosen to be 50°C following an average geothermal gradient of 25°C per kilometer. The initial pressure at the middle of the injection formation was set to 12 MPa, according to a hydrostatic pressure distribution.

In the simulations, the model domain takes advantage of the symmetry condition of a 5-spot well pattern and only considered one hot-cold well pair, located at opposite corners of the simulation grid (Figure 3). Figure 9a shows the finite element mesh used in the simulations. The mesh is refined near the injection well. One alternative injection-pumping strategy is to thermally "charge" the reservoir for some time before the daily injection-production operation cycle starts. In such a scenario, the solar-heated water will be injected into the reservoir via hot wells for 8 hours every day without subsequent production of the heated water. Figure 9b shows the temperature field after six months of "thermal charging." After this 6-month "thermal charging," the conductive heat transfer into the over- and underburden rocks is negligible.

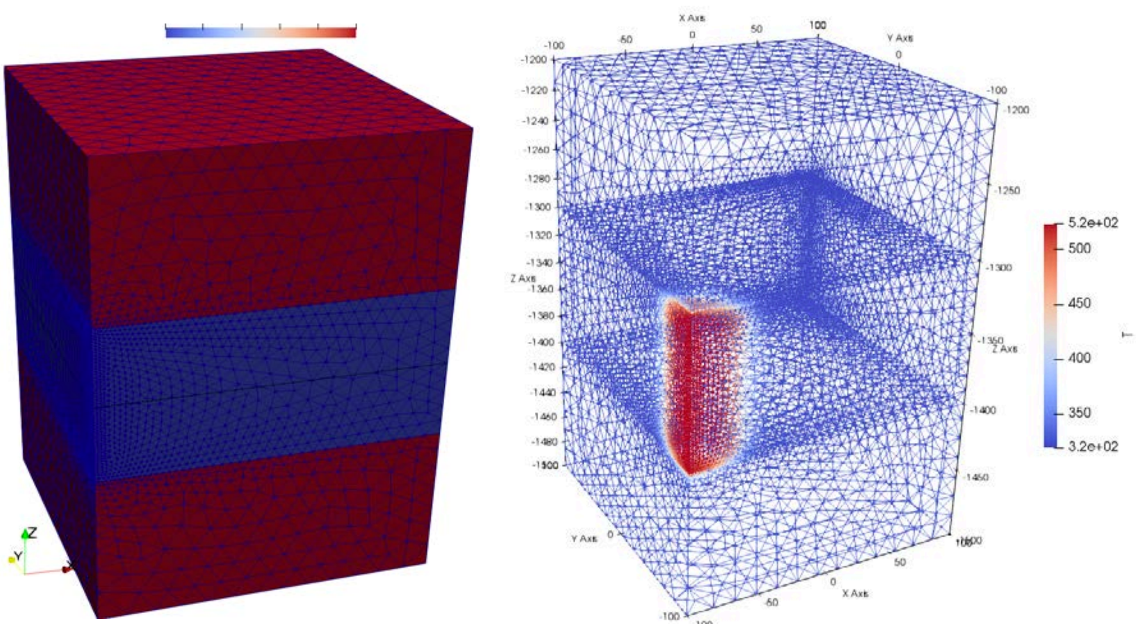

Figure 9. (a) Finite element mesh used in the simulations (left); (b) Temperature field (in Kelvin) of the reservoir after 6-month of "thermal charging" by injection of solar-heated water of 250°C at 40 kg/s for 8 hours each day (right).

One important factor for the effectiveness of subsurface heat storage is the temperature of water produced from the "hot" wells and potential temperature decline after continuous operation. Figure 10 shows the simulated temperature variations of water at a "hot" well over 30 days of continuous injection-production operation cycles for various "thermal scenarios." For the case of no "thermal charging" at all, initially large temperature oscillations are observed. This thermal oscillation starts to decrease gradually over the injection-production cycles, with an oscillation of ~50°C after 30 days and continuously decreasing. For the case of a 180-day (6-month) "thermal charging" scenario, the temperature oscillation is minimal, within ~2-3°C fluctuation over the 30-day injection-production cycles.

These initial simulation results indicate that the subsurface is a very good candidate for heat storage, and the push-pull injection/pumping strategy could be very promising for coupling underground solar heat storage with power plants.

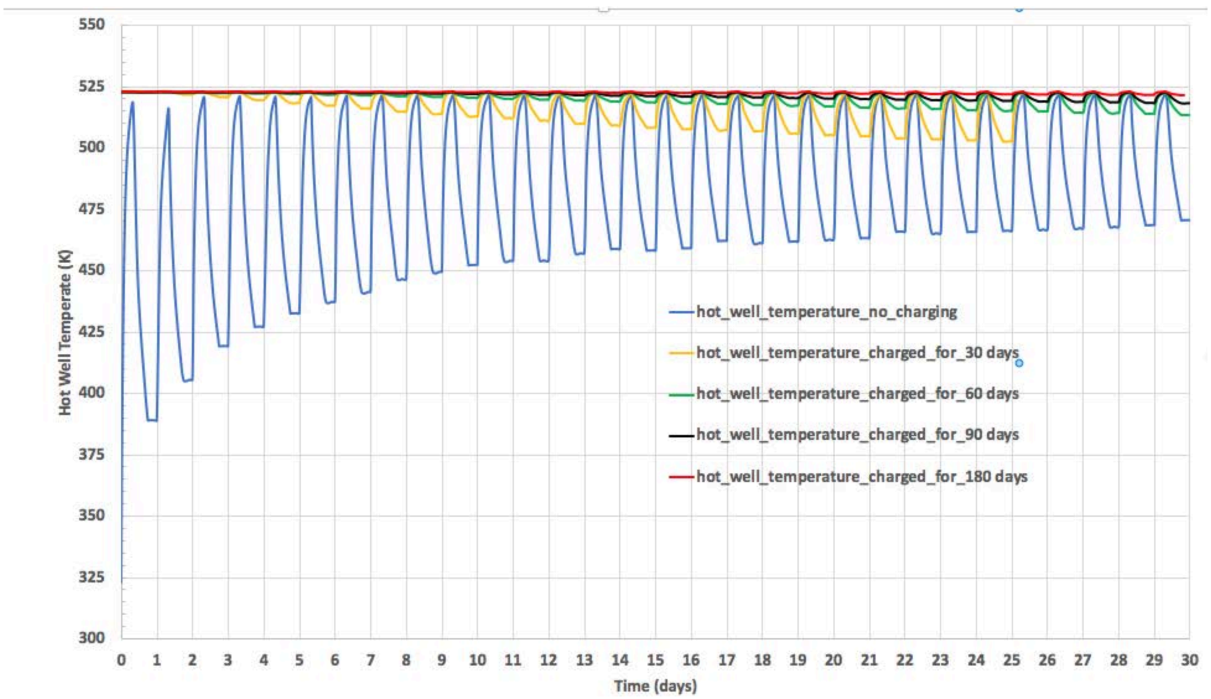

Figure 10. Simulated temperature variations of water at the "hot" well over 30-day continuous injection-production cycles for various "thermal charging" scenarios in which heat is added and recovered from the GeoTES.

4. Power cycle analysis

The objectives of the power cycle analysis include:

1. Optimal condenser operating pressure
2. Optimal flash temperature selection
3. Economic analysis and LCOE (levelized cost of electricity) calculation

The input parameters used for designing the power cycle are:

1. Gross power produced: 40 MW_e

2. Ambient air temperature: 25°C
3. Hot geothermal well condition: 250°C and 50 bar
4. HTF solar field pumping is calculated from SAM (10.3 kW_e/kg of HTF)
5. Condenser for the power cycle: Air-cooled condenser

The assumptions used while modeling the power cycle are:

1. Mass of water extraction from a well (m_{well}): 40 kg/s
2. No heat loss from the geothermal well
3. Isentropic efficiency for the turbine and pump: 85%
4. Pressure drop in air cooler: 150 Pa
5. A standard steam ACC is a reasonable representation in the model of the preferred system of a DCC and an ACWC (See Section 2).

To model the power cycle SimTech IPSEpro is used. The power cycle is specified to deliver a gross power output (P_{gross}) of 40 MW_e. The net power supplied from the power cycle (P_{net}) is:

$$P_{net} = P_{gross} - P_{pump}\begin{pmatrix}\text{Air Cooler} + \text{Compression of working fluid in the power cycle} \\ + \text{Geothermal Storage}\end{pmatrix} \quad (1)$$

The overall efficiency (η) is given as:

$$\eta = \frac{P_{net}}{\dot{m}_{w,geo}\left(h_{in} - h_{out}\right)} \quad (2)$$

where,

$\dot{m}_{w,geo}$ = mass flow rate of water from the geothermal well(s) into the flash vessel

h_{in} = enthalpy of hot water entering the power cycle (250°C and 50 bar)

h_{out} = enthalpy of cold water leaving the power cycle

4.1. Optimal condenser operating pressure

Figure 11 shows the variation in the cycle efficiency and mass flow rate of water required with condenser operating pressure. The steam flash temperature considered is fixed at 160°C. The cycle efficiency is maximum at 0.1 bar-absolute (18%) and decreases linearly with an increase in pressure. Because of higher efficiency, the net mass flow rate of geothermal water is low at a lower condenser pressure. Due to higher efficiency and lower mass flow rate, the condenser operating pressure for the steam turbine is selected to be 0.1 bar-a (1.45 psia, 3” of mercury).

IPSEpro has a built-in module for a conventional steam ACC. This module was used in place of developing a full operating model of the preferred system of a direct contact condenser (DCC) and an air cooled water cooler (ACWC) as described previously.

4.2. Variation in flash temperature

Figure 12 shows the variation in cycle efficiency and water mass flow rate for the two-stage flash steam cycle. With increases in flash temperature, the net heat available for power production per unit mass of water decreases and this leads to an increase in the mass flow rate of water. For 160°C (320°F), the required mass flow rate of water is 328 kg/s (2.6MMlbs/hr), and at 240°C (464°F), the net mass flow rate of water required is 600 kg/s (4.8MMlbs/hr). The consequence of this higher flow rate is that a greater number of wells is required.

As would be expected from the second law of thermodynamics, the efficiency of the cycle increases with higher turbine operating temperature. Thus higher turbine inlet temperature yields higher production of electricity per unit mass of water supplied. This both mitigates the number of new wells needed, but more importantly reduces the capital cost of the required solar thermal collectors. The effect of the increase in electricity production is more dominant compared to the increase in water flow rate, and this results in an increase in overall efficiency and lower capital cost with increasing flash temperature. The cycle efficiency increases from 18% to 23%, as the first stage flash temperature is increased from 160°C to 240°C. For all optimization runs, the second stage flash temperature was fixed at 30°C below the first stage flash temperature as a simplifying assumption. However, as is discussed in the next section, the optimum flash temperature was shown to be between 205 and 220°C.

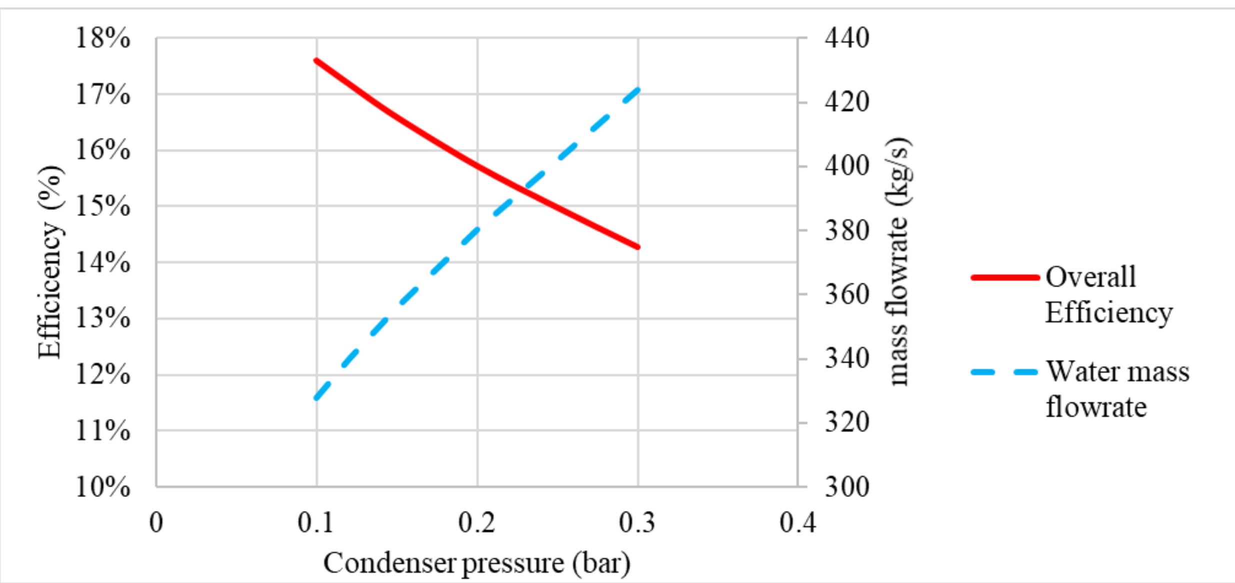

Figure 11: Variation in cycle efficiency and water mass flow rate with condenser pressure. The steam flash temperature considered is fixed at 160°C. The power plant net output is fixed at 40 MW$_e$.

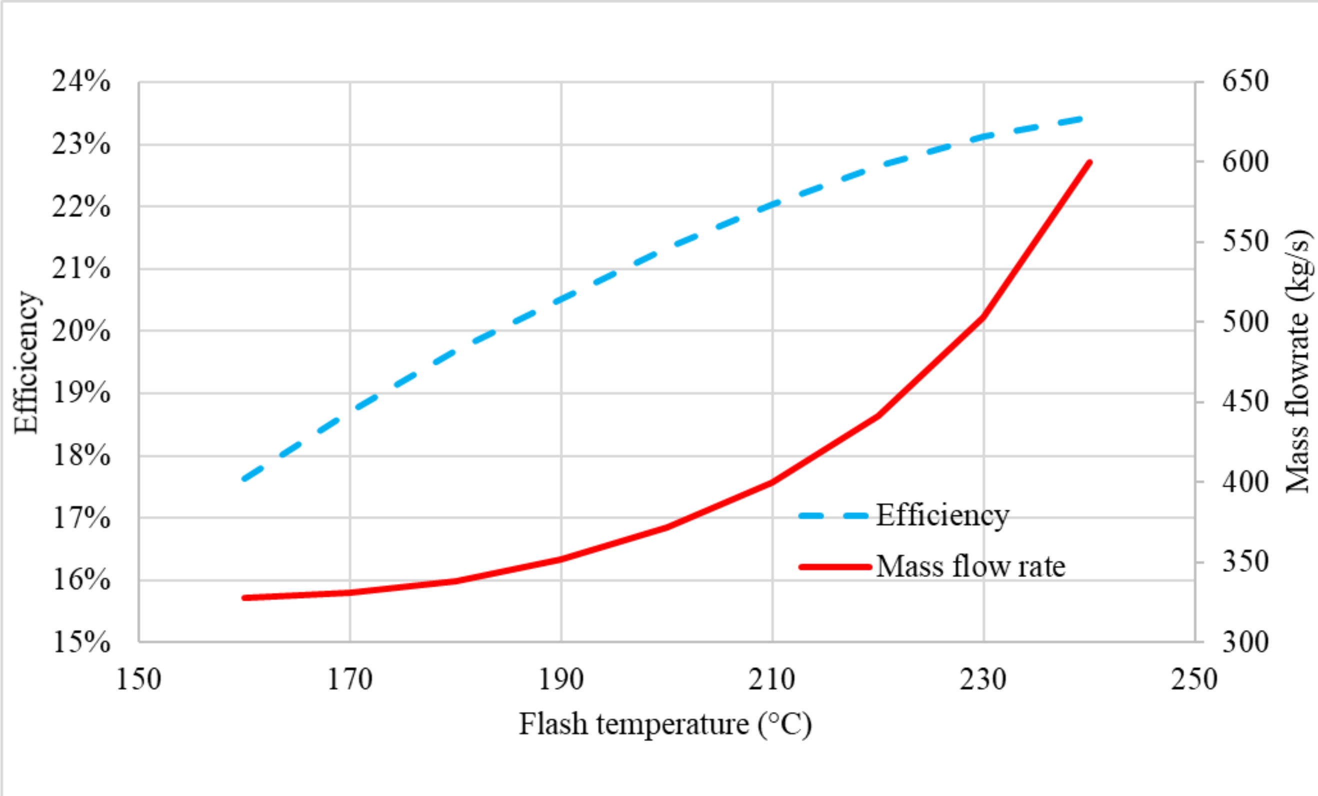

Figure 12: Variation in mass flow and overall cycle efficiency with variation in flash temperature. The power plant net output is fixed at 40 MW_e.

5. Economic analysis

To further evaluate the performance of the cycle a first order economic analysis was performed. Cost parameters used in the analysis include:

Cost of GeoTES well pair: $2 MM (hot well + cold well + cold well downhole pump).
Cost of steam power cycle: $1.5 MM/MWe
Cost of solar: $150/m²
Land cost: $5/m²
Water cost: $0/kg
O&M solar: $7.4/kWth/year
O&M geothermal and power block: $25/MWhe

Since the GeoTES wells are being drilled in soft sedimentary formations to create a synthetic geothermal reservoir, the low drilling costs of traditional oil and gas wells are more applicable than the costs of hard rock drilling in geothermal formations.

Figure 13 shows the variation in capital cost with flash temperature. The minimum capital cost per unit electricity generation is approximately 4.2 M$/$MW_e$ for a flash temperature of 210°C. The capital cost escalates with increases in flash temperature beyond 220°C. This increase in capital cost is because increases in flash temperature require higher water flow rates to produce the specified level of power generation, which in turn results in a greater number of wells with increased capital costs.

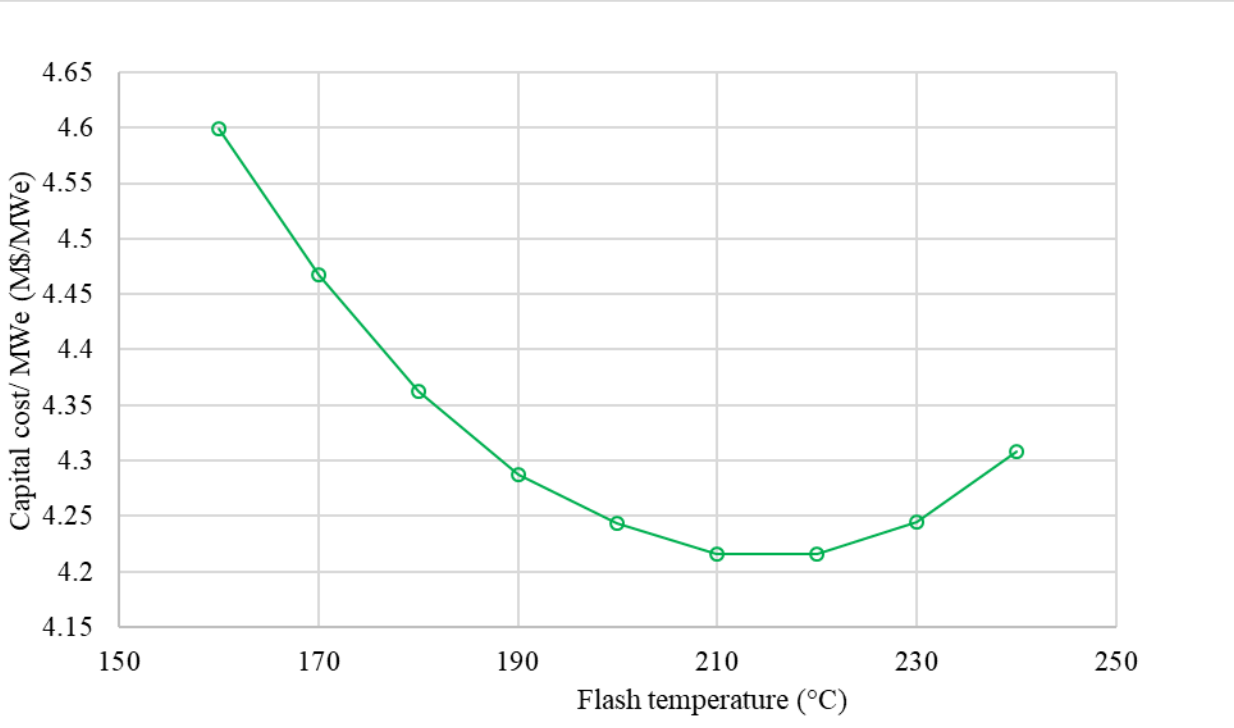

Figure 13: Variation in capital cost for unit electricity generation with flash temperature.

To calculate the levelized cost of electricity (LCOE), an annual simulation is performed using typical meteorological year (TMY) data. Minimization of the LCOE involves repeating the annual simulations with a varying solar multiple (SM) to identify the optimal SM (SM_{opt}). The solar multiple determines the solar field size as well as the number of wells required to accommodate the increased flow rate of hot water that must be injected into the hot wells; the capital costs are therefore affected by the SM specification. A solar multiple of 1 in this analysis produces enough solar heat at the design point irradiance onto the solar collectors to produce the required power plant design point heat input. Solar multiples above 1 are generally used in order to provide full capacity across more hours of the year, or in the case of Geo TES to increase the number of hours over which the power plant could operate.

With GeoTES, the SM_{opt} was greater than would normally be selected for a solar thermal power plant. Figure 14 shows variation in the LCOE for different solar multiples. For SM = 1, the LCOE comes out to be \$0.17/kW_e. At a lower SM, the net heat from the sun cannot be used effectively, and this results in higher LCOE. With increase in SM, the solar collector area and the number of wells increase, and this leads to an increase in total energy stored in the Geo TES and thus the number of hours that the Geo TES can discharge to provide flexible generation on a seasonal basis. The minimum LCOE of \$0.13/kW_e for the system is obtained for SM = 3.8. Any further increase in SM does not increase the heat utilization rate in the same proportion which leads to higher LCOE.

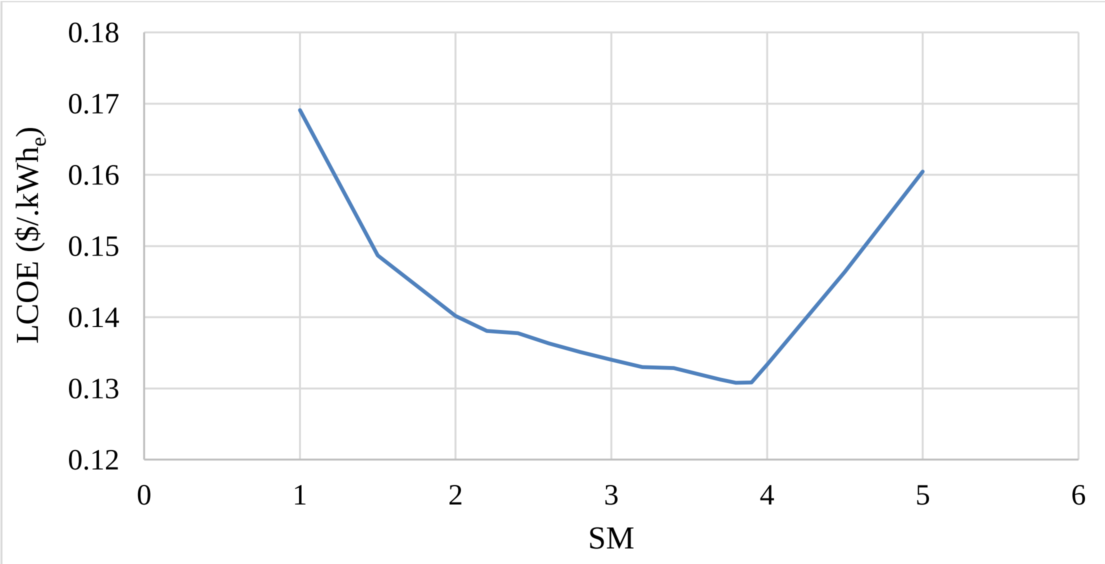

Figure 14: Variation in LCOE for double stage flash steam cycle (210°C / 180°C) with solar multiple.

6. Conclusions

- Use of GeoTES for solar thermal heat storage coupled with proven geothermal power generation technology provides a unique fully dispatchable seasonal energy storage capability for both capacity (MW) and energy (MWh). The overall system provides a foundation to support grid stability, reliability, and flexibility and can provide grid ancillary services. The system has the potential to allow and integrate even larger quantities of variable wind and solar PV generation by providing non-fossil based backing at lower cost over longer durations than battery energy storage. This unique capability provides a potential pathway for the nation's energy infrastructure to evolve more quickly to renewable, carbon-free electric sources and a sustainable energy future.
- System economics are optimized in configurations with a solar multiple greater than 1 (SM > 1). These configurations allow the GeoTES system to be charged during periods of high solar insolation. The charging provides the energy storage reserves necessary to generate power during periods of low solar insolation.
- The minimum Levelized Cost of Energy (LCOE) obtained for the GeoTES system is $0.13/kW$_e$ with an optimal solar multiple of 3.8.
- The LCOE for high capacity GeoTES systems is lower than the value of $0.148/kWh estimated by McTigue et al. (2018a, 2018b) for a low capacity (4 hr) photovoltaic plus battery energy storage (PV+BES) system. Addition of increased BES capacity would result

in significant increases in PV+BES LCOE. The GeoTES system would, therefore, provide superior economics for high capacity and long duration solar energy storage.

- A five-spot well pattern with dedicated hot and cold wells operated using a push-pull strategy provides (1) the ability to immediately recover stored hot fluid from the GeoTES reservoir, (2) a practical approach for managing the system fluid inventory, and (3) reduced parasitic load. Pressure support is provided from the wells operating in “push” mode to the wells operating in “pull” mode.
- Initial charging of the GeoTES system increases the heat recovery temperature. Increasing the duration of the charging period decreases the magnitude of the temperature fluctuations that occur following prolonged system operation.
- A dual-stage flash steam cycle provides lowest capital costs per unit net power generation with acceptable hot brine inlet fluid flow rate (i.e., low number of wells and associated parasitic loads). Other flash and binary cycle configurations had higher LCOE.
- The LCOE is minimized at the optimal solar multiple (SM_{opt}).
    - At $SM > SM_{opt}$ the additional capital costs associated with the solar field and GeoTES wells do not result in significant increases in annual power generation, i.e., minimal additional power sales revenue is realized from significant increases in capital cost.
    - For $SM<SM_{opt}$ there will be greater durations of time when the GeoTES energy storage is depleted, i.e., no hot brine remains in the GeoTES reservoir, and electrical power cannot be generated to provide revenue during these times.

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