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Hybridizing Solar Heat with a Geothermal Binary Power Plant Using a Solar Steam Topping Turbine

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ABSTRACT

Solar-thermal hybridization is a way to boost power generation of geothermal power plants, especially when the geothermal resource cannot supply the design flow or temperature. A new process using a high-pressure steam topping turbine can almost double the conversion rate of solar energy to power compared to the common practice of solar brine heating, and thus improve economic viability. This study looked at one such plant. Output from a geo-solar hybrid is typically increased both from the additional solar energy and from restoring turbine design-point efficiency. In this new process, a third effect occurs: the addition of a solar topping cycle increases the geothermal energy extracted from the brine. Process flow diagrams, off-design results, and economic results are presented. Three representative geothermal locations in the U.S. are evaluated, as are the effects of thermal storage, solar field sizing, and tax incentives.

1. Introduction and Motivation

Greater deployment of moderate temperature geothermal binary power plants (GBPP) and concentrating solar power (CSP) are both limited in some markets by their respective generation characteristics and/or levelized cost of electricity (LCOE). Worldwide, both geothermal and CSP are under intense pressure from the rapidly dropping cost of solar photovoltaic (PV) and wind energy. In the U.S. there is further pressure from the ongoing era of low natural gas prices

CSP can generate high temperature thermal energy enabling high cycle efficiency and low-cost thermal storage systems and GBPP can produce baseload power generation. Hybridization may take advantages of technical merits of both technologies to produce energy at an LCOE competitive in the future energy market, and thereby increase the adoption of both technologies.

The motivation for this article (and several previous investigations) is the decline in geothermal resource mass flow rates, temperatures, and/or pressures that occur at some geothermal power plants. When it is not possible to restore output with makeup drilling, to keep plant output constant, the unfilled portion of the GBPP's power sales contract provides an opportunity to install a concentrating solar plant at reduced cost since there is spare capacity in the turbine and heat rejection system (condenser and cooling tower).

In this paper, a new hybrid concept is investigated. A high-pressure steam topping cycle first extracts work from a concentrating solar field. The relatively high-temperature steam turbine exit flow is then used as an additional heat source to the Raft River GBPP in Idaho, USA which currently operates below its rated capacity.

Various hybrid plants have been previously suggested for both flash plants and binary plants. For flash plants, solar collectors can directly heat geothermal fluids, thereby increasing the fluid enthalpy and the steam generation (Lentz & Almanza, 2006). Alternatively, superheating the steam after the flash tanks was found to be more effective than evaporating the brine (Miguel Cardemil et al., 2016). Other studies concluded that recirculating and heating brine after the first flash plant was the most practicable and effective method, and also evaluated the benefit of thermal storage (J. McTigue et al., 2017; J. D. McTigue et al., 2018a; J. D. McTigue, et al., 2018c). Notably, these studies found that a hybrid plant with storage was more cost-effective than solar photovoltaics with battery storage.

Hybridization of solar heat with binary geothermal plants typically involves different integration methods to flash plants, although pre-heating the geothermal fluids has also been investigated in this context (Ghasemi et al. 2014). Other strategies involve superheating the binary cycle working fluid (Astolfi et al., 2011) or using the solar heat to drive a topping cycle – either as part of the binary plant (Zhou et al. 2013) or in a steam turbine (Bonyadi et al., 2018), thereby making better use of relatively high-exergy solar heat. These studies find the LCOE to be relatively high, obtaining values such as 0.163 \$ / kWh_e (Bonyadi et al., 2018) and 0.22 – 0.43 \$ / kWh_e (Astolfi et al., 2011). However, the estimated solar field costs in the range of 250 – 300 \$ / m^2 are used, which are high compared to recent estimates which are closer to 150 – 200 \$ / m^2. This is particularly relevant given that the solar field cost dominates the total capital cost.

1.1 Description of Raft River geothermal power plant

Raft River uses a dual pressure level binary cycle (organic Rankine cycle) and was designed and constructed by Ormat. The basic power cycle was described in detail in two previous publications (DiPippo, 2016; DiPippo & Kitz, 2015). A high-pressure (HP) and low-pressure (LP) turbine are connected on either side of a common generator. Both sides are separated from each other, and use isopentane as the working fluid. The heat rejection system is a shell and tube condenser with a 4-cell cooling tower. Geothermal brine flows into the HP and LP vaporizers in series, and then the brine splits to feed the pre-heaters of both systems. The cooled brine is then injected into the geothermal reservoir. A schematic is presented as Figure 1 and the current performance is compared to design performance in Table 1.

The plant began commercial operation in 2006 and has run at a high plant availability since. However, the reservoir was never able to provide sufficient flow to the plant, and so the output of the plant has been below the contract maximum.

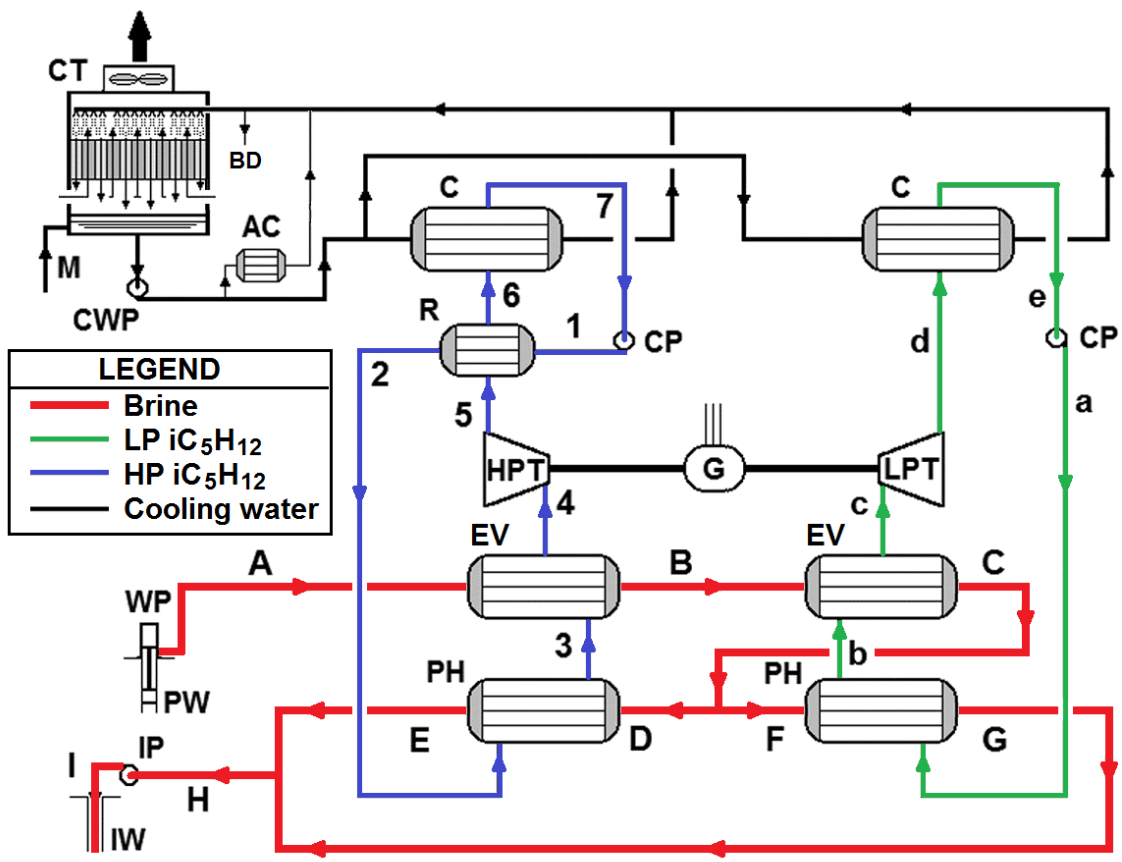

Figure 1: Raft River Geothermal Power Plant Process Flow Diagram. Key: CT: cooling tower; EV: evaporator (or vaporizer); HPT: High pressure turbine; LPT: Low pressure turbine; PH: Preheater; CWP: Cold water pump; PW: Production well; IW: Injection well; G: Generator; CP: Circulation pump; M: Makeup water; BD: Blow-down; IP: Injection pump; C: Condenser; R: Recuperator; AC: Auxiliary cooler

Table 1: Comparison of Design and Actual Operating Conditions and Generation

State	Description	Design Point		Current Ops	
	Geothermal Brine	Flow	T	Flow	T
		Klbs/hr	°F	Klbs/hr	°F
A	To Plant	3,150	280	2,700	272
H	From Plant	3,150	150	2,700	145
	Generation	MW_{gross}	MW_{net}	MW_{gross}	MW_{net}
Power Cycle, no brine pumps		15.9	13.7	13.8	~11.7

1.2 Design of the hybrid plant

Solar heat may be added in several ways to the Raft River GBPP. Five principles guided the approach to the integrated power cycle:

1. Use solar thermal energy, not photovoltaics (direct conversion of light to electricity).
2. Collecting solar energy is expensive, so high efficiency solar conversion (and therefore temperature) is required. Installing a steam turbine between the solar collector and the geothermal power plant provides an effective way to extract work from a high temperature flow.
3. Geothermal binary plants can convert low pressure steam at a similar efficiency to a steam turbine. Using existing capacity at a GBPP avoids the expense of a cooling tower system for the solar plant.
4. When adding solar heat to the geo-solar hybrid power plant, raising the geothermal brine exit temperature should be avoided. It is not cost-effective to use solar energy to heat up injectate.
5. Small high-pressure steam turbines are relatively inexpensive, as are heat exchangers when there is clean fluid on both sides, especially when boiling or condensing is involved.

These principles lead to the development of a conceptual design of geo-solar hybrid power plant, as shown in Figure 2, and several features are worth noting:

1. No changes to the Raft River GBPP were required other than isopentane piping inlet and extraction connections. (The four orange and purple lines that cross the dashed dividing line.)
2. The isopentane used in the solar heat cycle (purple and orange lines in upper half) is preheated by the geothermal brine. Directing a fraction of the isopentane to the solar heat cycle results in an overall increase in the binary cycle isopentane mass flow rate. This extracts additional geothermal energy from the brine in the pre-heaters. Interestingly,

adding solar energy increases the amount of geothermal energy that is extracted by the existing GBPP equipment.

3. The six heat exchangers shown in the upper half of the figure are only exposed to clean non-corrosive fluid, and all involve boiling and/or condensing which also reduces equipment cost. The small industrial steam turbine is also inexpensive.
4. The solar heat is collected using a heat transfer fluid (HTF), shown with green lines at the top of the diagram. Use of the HTF made plant performance and economic modeling easier using common software tools. It may be preferable to use direct solar steam boiling in actual practice.
5. The study was made using isopentane as the working fluid in the GBPP, but the results would be similar for any type of working fluid.

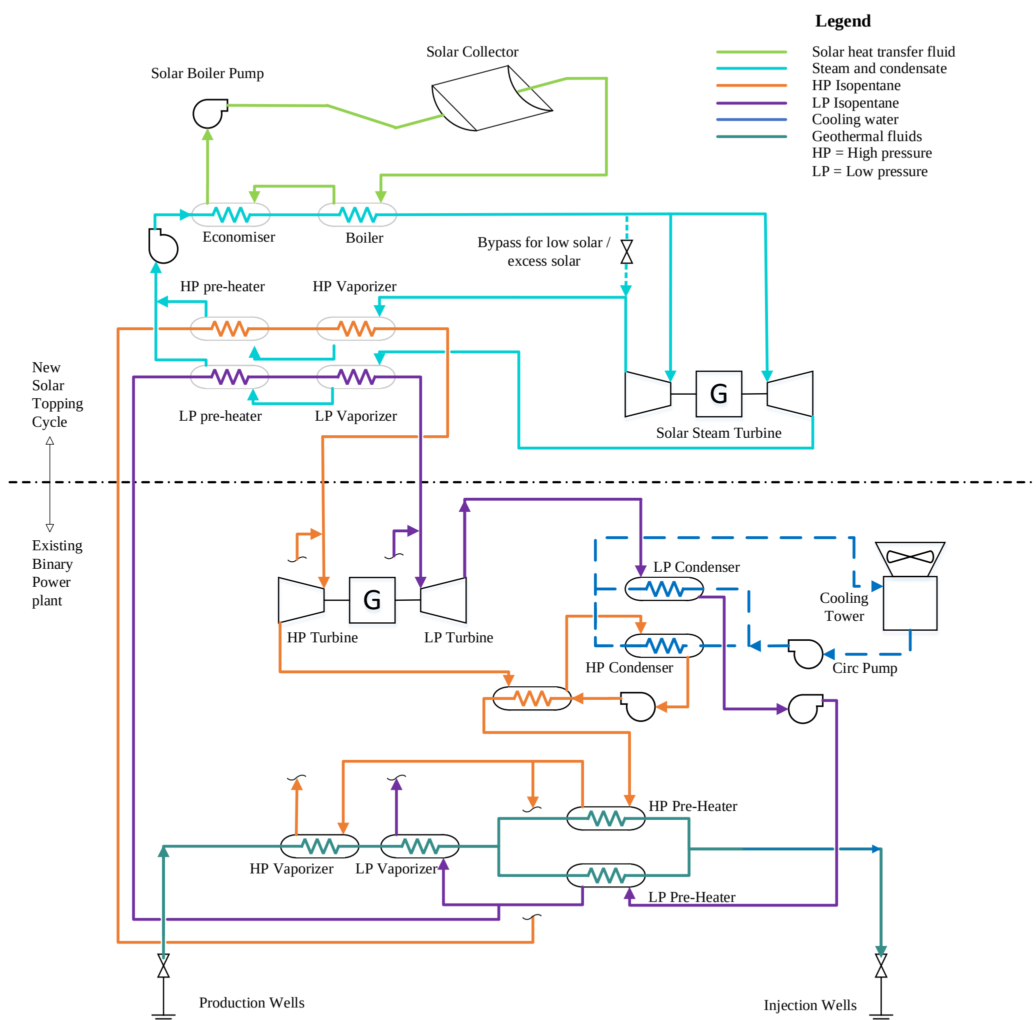

Figure 2: Process flow diagram of the hybrid solar-geothermal system with two steam turbines.

2. Screening Study of Various Configurations

A preliminary screening study was performed on several cycle configurations at a single operating condition in order to compare the proposed hybrid cycle with other commonly suggested methods. Subsequently a detailed study (section 3 onwards) considered several variations of the most efficient cycle for annual cost and performance considerations. Both the screening study, using one modeling software package, and the detailed analysis using another software package were calibrated against one or more aspects of the Raft River operating condition. However, variations in that calibration process make it so that the results from one model cannot be directly compared to the results from the other. The combined results of the screening and detailed study are shown in Table 2. The results are presented in approximate solar conversion efficiency ranking from best to worst. Full details of the modelling methodologies are provided in (J. D. McTigue, Wendt, et al., 2018b).

The hybrid cycle of Figure 1 was screened against two of the most common geo-solar cycles, namely a) adding solar energy to either pre-heat the entire brine flow to the GBPP, or b) heating a small slip stream of cooled geothermal brine and returning it to the incoming flow to the GBPP. The analysis showed that the cycle of Figure 1 has a conversion efficiency double that of the brine heating cycles efficiencies. The proposed geo-solar hybrid cycle also doubled the annual energy production (MWh/yr), and because of the high conversion efficiency, the size of the solar field was of a similar size, so solar field capital costs are similar.

Some key insights into the design of geo-solar hybrid configurations from the two modeling efforts are:

1. The studies confirm that creating and using high-exergy (high temperature, i.e. 700°F) solar energy creates up to twice as much net power using a steam turbine than if the solar energy is used directly to heat brine at moderate temperatures (i.e. < 300°F).
2. Multiple steam turbines and multiple steam extraction and heating points are the most efficient, but from a practical perspective, a single steam turbine and single heating point appears to be the preferred mode of converting the high-temperature steam, at least for the relatively small installation being considered at Raft River.
3. The most efficient cycles reduce the brine temperature exiting the plant, effectively using solar energy to increase the extraction of geothermal energy.
4. The best cycles use the solar energy to vaporize the GBPP working fluid.
5. The worst cycles add heat and/or flow to the incoming brine flow to the GBPP.
6. If brine heating is undertaken, it is best to heat the incoming flow to the GBPP, rather than recirculate and re-heat brine from within the GBPP.
7. Cycles that heat brine using a steam topping turbine are significantly more efficient than cycles that directly heat the brine with the collected solar energy.

Table 2: Comparison of different hybrid plant configurations from the screening study (section 2) and detailed study (section 3). '—' indicates the configuration was not studied

Cycle and Description	Design-Point Cycle Efficiency		Annual Efficiency
	Screening Study	Detailed Study	Detailed Study
Two solar steam turbines: Use high-T solar steam in two turbines, which exhaust to HP and LP isopentane boilers. Isopentane vapor is used in the GBPP isopentane turbine.	35%	33%	30%
One solar steam turbine with steam cross-over: Eliminate the small turbine to the LP isopentane boiler, and instead use some of steam from HP turbine exhaust to feed the LP isopentane boiler.	—	32%	29%
One solar turbine with geo-heat bypass: All solar turbine steam is used on HP side. Eliminate LP steam isopentane boiler. Reduce geo heat extrac-tion from the HP side of the GBPP and bypass it to the LP geo-boiler.	—	32%	29%
Solar steam turbine to reheat internal brine slip-stream: Use one steam turbine, and then recirculate and reheat brine from inside the GBPP, either after the HP or LP vaporizers.	27% to 30%	—	—
One solar turbine to heat incoming brine: One solar turbine is used to heat the entire flow of brine coming into the GBPP. This raises temperature but not flow. Calcium mineral precipitation is a risk.	—	—	—
One solar turbine to reheat brine from plant exit: A slipstream of brine from the plant exit is reheated and added back to the inlet flow, increasing brine flow to the plant, and possibly temperature as well.	24% to 27%	—	–
Directly heat incoming brine with solar energy: No high-temperature solar steam turbine. Heat all incoming brine with direct solar energy.	16%	16%	16%
Directly heat brine from exit with solar energy: No solar steam turbine. Heat exit brine slipstream with solar energy, recirculate to plant inlet.	—	13%	13%

3. Detailed Modelling Methodology

Detailed models of the hybrid plant were developed in the flow-sheeting software IPSEpro (SimTech, 2017) and included the geothermal plant and the additional heat integration from the solar field. The performance of the solar collector field was evaluated using the System Advisor Model (SAM) (National Renewable Energy Lab, 2017). This model calculated the ambient temperature and solar thermal heat available to the hybrid plant at every hour of the year. The output of these two models were combined in an Excel spreadsheet and the hybrid plant performance was calculated for every hour of the year. The annual calculations were then used to evaluate the LCOE. Additional details of the modelling methodology are now provided, and further specifics may be found in (J. D. McTigue, Wendt, et al., 2018b).

3.1 Modelling of the original Raft River GBPP with IPSEpro

SimTech IPSEpro Process Simulation Environment version 7.0 U, Release 12, Build 1744 software was used to model the performance of the Raft River geothermal power plant both with and without the addition of the solar topping cycle. Process flow diagrams of the Raft River power plant obtained from US Geothermal provided the mass and energy balance data used to develop the ORC power block model. The Raft River design point process flow diagram was used to establish equipment sizing parameters, and design point process operating conditions and performance. The Raft River off-design process flow diagrams were used along with additional equipment performance specification data to adjust the model input parameters to accurately simulate off-design process performance.

3.2 Addition of solar heat to the Raft River GBPP in IPSEpro

Following verification of the model's ability to adequately predict gross and net power output of the GBPP, the solar topping cycle was added to establish the integrated hybrid plant model. While the GBPP model input parameters were specified in order to provide the best match with existing plant design and operating data, the solar topping cycle design configuration and input parameters were chosen at the discretion of the project team with the overall goals of maximizing power output and minimizing capital costs for additional topping cycle equipment. Key solar topping cycle design configuration and input parameters include:

- Steam Rankine cycle heat input is obtained via heat exchange with a heat transfer oil that is circulated through the solar field.
- Turbine inlet conditions of 700°F and 1200 psia
- Turbine design isentropic efficiency of 75% based on personal communication with steam turbine manufacturer
- Total steam cycle pressure drop of ~100 psi assumed to account for losses in heat exchangers (economizer, boiler, superheater, and condenser), control valves, and piping.

3.3 Determination of plant performance for a typical meteorological year

To fully assess the benefits of geo-solar hybridization of the Raft River geothermal plant, the total additional annual power generation that results from hybridization is evaluated. This required estimation of the annual power generation for both the unmodified Raft River plant and the proposed Raft River hybrid power plant assuming identical geothermal resource and ambient condition data. Power plant performance for the unmodified and hybrid plants was characterized by using multiple linear regression of IPSEpro simulation output data to establish correlations that predict net power output as functions of wet bulb temperature and solar heat input (hybrid plant only). The regression functions were then used to predict hourly power plant net output from the wet-bulb temperature and solar field heat output data.

The annual net power generation is multiplied by a capacity factor of 95 % to represent maintenance or down-time. Following correspondence with the Raft River geothermal plant, this value is deemed to be conservative, as actually capacity factors are 98 – 99 %.

3.4 Solar field modelling with SAM

Annual thermal output of the solar field is generated using NREL's System Advisor Model (SAM) (National Renewable Energy Lab, 2017). The solar collector is a parabolic trough and is modelled with the "Physical Parabolic Trough Model" in SAM. Therminol VP-1 oil is used as the heat transfer fluid and the solar field design outlet temperature is 391^{o}C. The individual loop size and control system of the model is altered such that no defocusing of the solar field occurs, under the assumption that thermal energy production that exceeds the turbine's limitations can bypass the solar field turbine and be used elsewhere in the geothermal plant. Hourly irradiance and wet-bulb temperatures were provided by typical meteorological year (TMY) data from SAM TMY data provides solar input conditions based on expected normal hourly variations (not long-term averages) in key parameters. The mass flow rate of the heat transfer fluid is allowed to vary in order to reach the desired solar field outlet temperature during varying solar resource, which is the common method of control in CSP plants.

3.5 Economic model

The economic evaluation considers the costs of the additional equipment required to retrofit the Raft River GBPP. It is assumed that any expenses incurred in the modification of the ORC piping, instrumentation, etc. due to solar hybridization are included in the hybrid plant retrofit equipment installation costs.

The capital cost estimate for the solar topping cycle power block includes major equipment items such as heat exchangers, pumps, and turbines. The steam topping cycle hybrid plant configuration uses three heat exchangers for transferring heat from the solar field HTF to the water in the steam Rankine cycle; these include an economizer, vaporizer, and superheater to generate superheated steam from the subcooled boiler feed water. Additionally, two condensers transfer the thermal energy from the steam condensation process to the high-pressure and low-pressure ORC working fluid.

Two programs from AspenTech were used to determine the capital and installation costs for the heat exchangers and pumps: Aspen Exchanger Design and Rating V10 and Aspen Process Economic Analyzer V10.

The steam topping cycle turbine costs are assumed to be \$500/kW for the L1 turbine-generator and \$1100/kW for the L2 turbine-generator (United States Department of Energy, 2016). Steam turbine O&M costs are assumed at \$0.01/kWh (United States Department of Energy, 2016).

Based on recent developments in solar collector design and manufacture, the solar collector cost is assumed to be 100 \$ / m^2. The installation of the solar field also requires site improvements (25 \$ / m^2) and a heat transfer fluid, including piping and pumps (60 \$ / m^2). The annual operating cost associated with the solar field is 8 \$ / kW$_{th}$.

A detailed listing of individual equipment component sizes and capital costs is provided in (J. D. McTigue, Wendt, et al., 2018b).

3.6 Hybrid plant metrics

Levelized cost of electricity (LCOE)

The levelized cost of electricity (LCOE) is the cost that, if assigned to every unit of electrical energy produced over the lifetime of the plant, will equal the total life cycle costs when both are discounted back to the current year (Short & Packey, 1995). In the case of the hybrid plant where the power block and geothermal wells already exist, the annual electrical energy generated by the solar equipment addition is the marginal increase in electrical energy above the base rate provided by the geothermal plant. Thus, the costs and power generation of the existing Raft River GBPP are not included in the LCOE calculation.

The LCOE is calculated using the fixed charge rate (FCR) method, where

$$\mathrm{LCOE} = \frac{C_{\mathrm{cap}} \cdot \mathrm{FCR} + M}{E} \qquad (1)$$

Where C_{cap} is the capital cost, M is the annual operations and maintenance cost, E is the annual electricity generation, and FCR is the fixed charge rate. FCR is defined as the revenue per unit of investment that must be collected annually to pay for the carrying charges of the investment. Details of how to calculate the FCR may be found in (Short & Packey, 1995), and the economic assumptions used in this study are given in Ref. (J. D. McTigue, Wendt, et al., 2018b).

Hybrid plant efficiency

The solar-conversion efficiency, also referred to as the incremental or marginal solar efficiency, measures how effective the hybrid configuration is at converting the additional thermal input (i.e. the solar energy added) into useful work (net power, which is the gross power minus the associated parasitic loads). Two definitions exist and differ in the denominator. In one definition, the incremental solar energy added to the cycle is that which is actually collected and transferred to the main power cycle. The second is where the incremental solar energy is that which actually falls on the collector. The first definition is preferred here since this was a study of cycle efficiency, not collector efficiency.

Thus, the first version of the incremental solar efficiency is defined as:

$$\eta_{\mathrm{sol,1}} = \frac{\dot{W}_{\mathrm{net}} - \dot{W}^{o}_{\mathrm{net}}}{\dot{Q}_{\mathrm{add}}} \qquad (2)$$

Where $\dot{W}_{\mathrm{net}}$ is the net work produced by the hybrid plant, $\dot{W}^{o}_{\mathrm{net}}$ is the net work that would have been produced by the geothermal plant in isolation, and $\dot{Q}_{\mathrm{add}}$ is the thermal power added to the hybrid power cycle. It does not consider the efficiency of the production of that heat, e.g. the efficiency of the solar collector. It is therefore an indication of the effectiveness of the hybrid power cycle. $\eta_{\mathrm{sol,1}}$ may be used to compare the performance of different power systems proposed in the literature without considering differences in the solar collection technology (including project specific choices of collector efficiency, or advancement over time in solar collector efficiency) or differences in modelling of the solar field (which can be done to variable degrees of complexity).

4. Results

In this section the calibrated thermodynamic modeling software and economic evaluation methods are brought together. The location of the hybrid is investigated. More advanced operation, such as including thermal storage and over-sizing the solar field are considered. The influence of key economic variables such as the inclusion of an investment tax credit are investigated.

4.1 Annual performance of hybrid configurations

Annual power generation and LCOE calculations are performed for several different hybrid plant configurations. In all cases the solar field was sized to restore the Raft River GBPP to its original design net generation (excluding loads outside of the power block, such as brine production and injection pumps.)

Several cycles were considered, and full results and discussion are provided in (J. D. McTigue, Wendt, et al., 2018b). The analysis found that brine preheating is the simplest to implement, and it has the smallest solar field. But it has a much lower marginal solar efficiency and higher LCOE than the configurations that use steam topping cycles. On the other hand, implementing a topping cycle allows for much more efficient use of the high-exergy flow that the solar field generates. For instance, this cycle has a efficiency of 29.6 % and an LCOE of 0.129 \$ / kWh_e.

A simple steam topping cycle that uses a single steam turbine was also evaluated. Although this system was less efficient (28.6 %), it has a lower capital cost, therefore leading to a lower LCOE of 0.126 \$ / kWh_e. This cycle used as the basis for the following results.

4.2 Influence of geographical location

In this section a solar steam topping cycle hybrid power plant is investigated in three locations: Burley, Idaho; Reno, Nevada; and Imperial, California; Input data is provided in Table 3.

In each case, the binary plant is assumed to have the same characteristics as the Raft River geothermal plant. No change is made to the size of the GBPP heat rejection system (condenser, cooling water pumps, and cooling tower), which means that it is undersized for the other two warmer locations. For Imperial, the smaller heat rejection system of the Raft River plant may have an especially large effect on annual generation, and hence the results of this study likely indicate a much higher LCOE than would actually occur.

Figure 3 indicates that ambient temperatures significantly affect the performance of the water-cooled geothermal plant, especially because it is undersized, as described above. Consequently, the hybrid plant has a lower solar conversion efficiency and produces less work from the geothermal field in Imperial, California due to much higher ambient temperatures. However, the improved solar resource leads to more available solar heat, thereby generating more power in the solar steam turbines.

Despite the hybrid plant in California producing less electricity annually, it has the lowest LCOE as shown in Table 4. This is because the LCOE for the hybrid plant is calculated using the electricity generated additional to the existing geothermal plant. The Californian plant produces the least electricity, but has the highest percentage increase in work output, thereby leading to low LCOEs.

The solar conversion efficiency shown here is $\eta_{\text{sol},1}$ and is a measure of the total increase in electricity divided by the solar thermal heat input to the hybrid plant. Using the total power incident on the solar collector instead gives the efficiency $\eta_{\text{sol},2}$. The annual average solar field performance (including optical and thermal efficiencies) for the solar field considered here is 45 – 48 %, leading to values of $\eta_{\text{sol},2}$ in the range of 12.7 to 13.7 %, as shown in Table 4. These values are comparable with values of $\eta_{\text{sol},2}$ proposed by other authors for hybrid plants with a solar topping cycle (Bonyadi et al., 2018).

Table 3: Typical solar properties at various geothermal plant locations in the USA

Annual average		Burley, ID	Reno, NV	Imperial, CA
Direct normal irradiance	kWh / m^2 / day	5.71	6.39	7.23
Global horizontal irradiance	kWh / m^2 / day	4.63	5.06	5.77
Wet-bulb temperature	°C	5.1	4.8	14.3
Elevation	m	1267	1341	-17

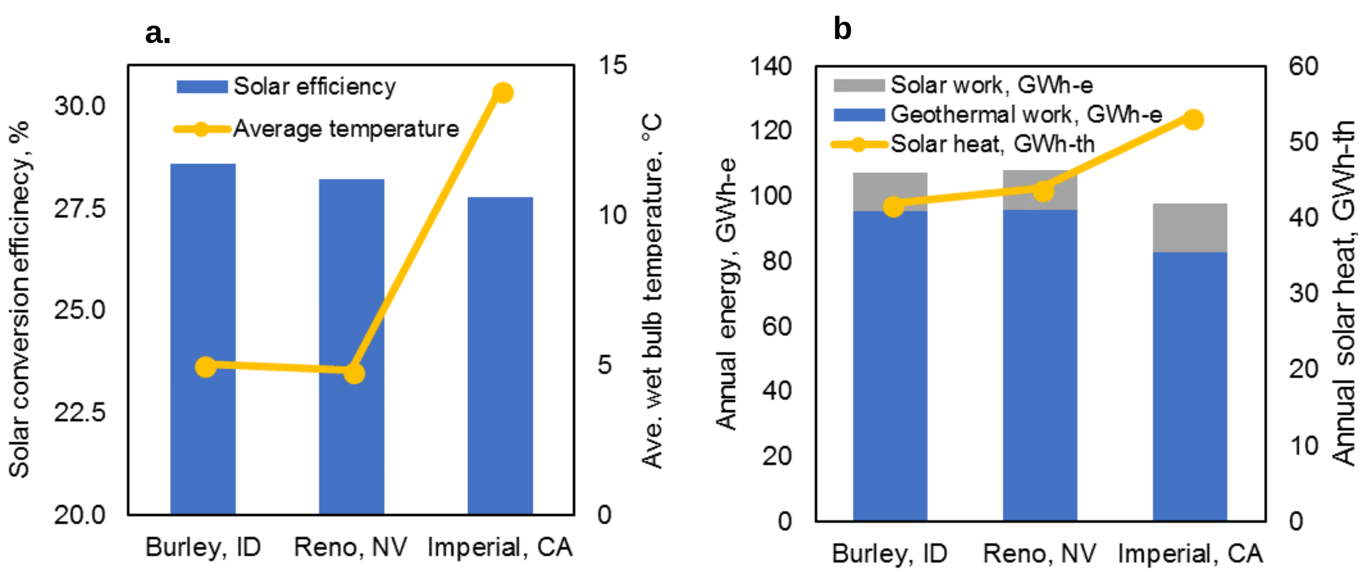

Figure 3: The influence of location on the hybrid plant performance. a) Higher average annual wet-bulb temperatures lead to lower solar conversion efficiencies. b) The geothermal power plant produces less electricity in warmer regions. However, more solar heat is generated.

Table 4: Electrical work output, solar conversion efficiencies, and LCOEs of hybrid plants in different geographical locations

		Burley, ID	Reno, NV	Imperial, CA
Stand-alone geothermal work	GWh_e	95.4	95.7	82.4
Additional work	GWh_e	12.0	12.4	14.8
Total work	GWh_e	107.4	108.1	97.7
Percentage increase	%	12.6	13.0	18.6
Solar conversion $\eta_{\mathrm{sol},1}$	%	28.6	28.2	27.8
Solar conversion $\eta_{\mathrm{sol},2}$	%	13.7	12.7	13.4
Solar field efficiency	%	47.9	45.0	48.2
LCOE	\$ / kWh_e	0.126	0.122	0.118

4.3 Optimal solar field sizing

The solar field is sized to produce 25 MW_{th} at a solar irradiance of 950 W / m^2: this design point has a solar multiple of 1 and at these conditions will restore the design performance of the binary cycle. These conditions occur only some of the time during the year, so that a system with a solar multiple of one would operate below design conditions for much of the year. To improve the number of hours that the integrated GBPP operates at or above the design conditions of the hybrid plant, the solar field area may therefore be increased, and the solar multiple increases proportionally.

Increasing the solar multiple increases the quantity of heat available to the hybrid plant, and the LCOE therefore initially reduces despite the increased capital cost. At large solar multiples, the solar field frequently produces more than 25 MW_{th}. Curtailing this excess heat leads to higher LCOEs, and Figure 4 indicates that the optimal solar multiple is ~1.25. However, hybrid plants have the added benefit that some excess solar heat can be absorbed by the binary plant. In this case, the optimal solar multiple increases slightly, and the optimum LCOE is slightly reduced.

4.4 Integrating thermal storage with solar field sizing in the Geo-Solar Hybrid

Thermal energy storage (TES) provides another avenue to avoid curtailment while also converting solar heat at higher efficiencies. Figure 5 shows the impact of TES on the LCOE of hybrid plants located in Burley, ID and Imperial, CA for different solar multiples. The TES is designed to deliver energy at the design rate of 25 MW_{th}, and they absorb solar energy from the solar collectors whenever the solar steam turbine has reached 100% of its design value. The storage duration (either 4 or 8 hours in this example) then determines the energy capacity of the TES. All excess solar heat enters the TES and once the TES is full the excess is curtailed. Whenever the solar heat decreases below 25 MW_{th} the stores are discharged until they are completely depleted.

This analysis assumes the storage is in the form of two liquid tanks that contain the solar heat transfer fluid. One of these tanks is used to store excess capacity of hot heat transfer fluid while the second tank is used to manage the inventory of cooled heat transfer fluid. This type of storage is comparatively straight-forward technologically and has been previously deployed at CSP plants. It is assumed that the tanks have been sufficiently insulated so that heat leakage losses are negligible over the storage duration (several hours).

The figures indicate that thermal storage increases the optimal size of the solar field to 1.5 for 4 hours of storage and to 2.1 for 8 hours of storage. Furthermore, when storage has a capital cost of 25 $ / kWh$_{th}$ the optimal LCOE is slightly lower than the system without storage, although this configuration requires a greater investment. Further analysis of storage costs indicated that costs over 35 $ / kWh$_{th}$ would lead to an optimum LCOE that was higher than the system with no storage. It should be noted that 25 $ / kWh$_{th}$ is quite an optimistic value and more realistic values for two-tank liquid storage are 30 – 50 $ / kWh$_{th}$.

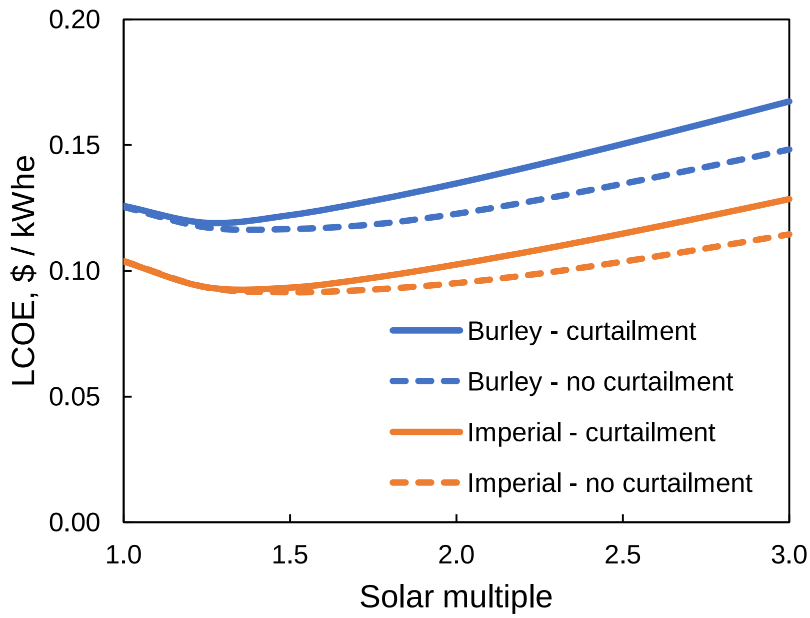

Figure 4: The effect of solar field size on the LCOE. Curves are shown for a hybrid plant with one turbine with the solar field orientated north-south. Solar heat is either curtailed or re-routed directly into the geothermal plant vaporizers.

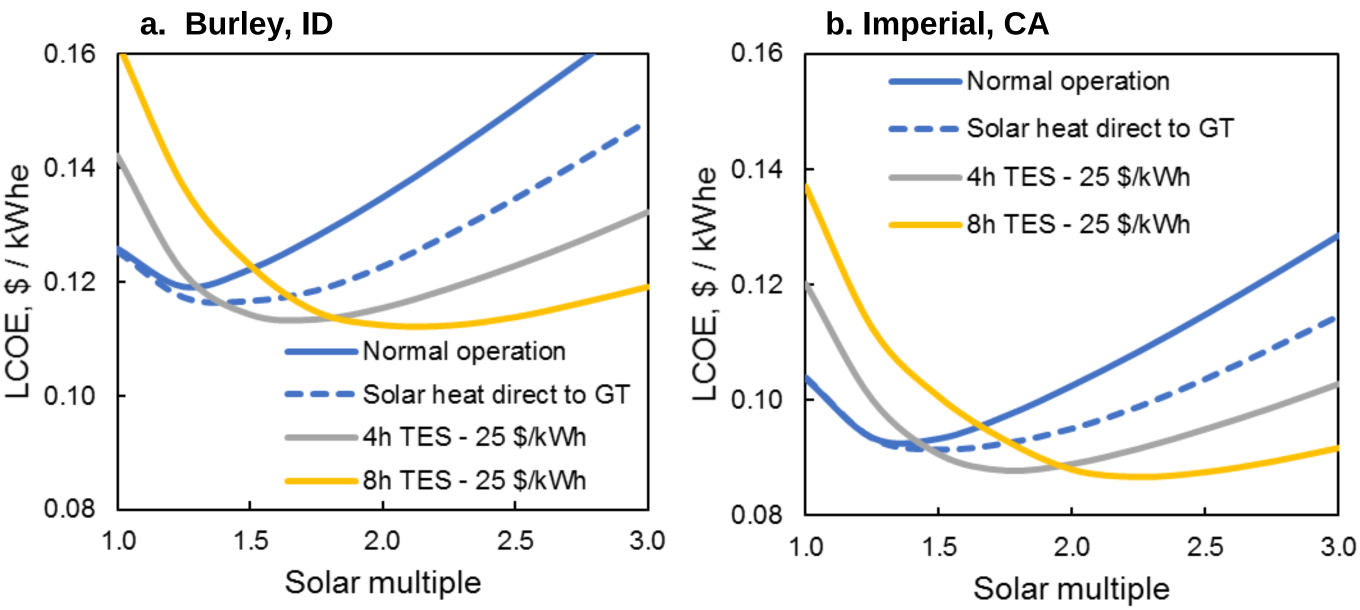

Figure 5: Thermal storage increases the optimal solar multiple. a) Hybrid plant at Burley, ID. b) Hybrid plant at Imperial, CA. Results are for a hybrid plant with one steam turbine with the solar field orientated north-south.

4.5 Effect of tax incentives on economic results

The results presented so far have been for the full expected capital costs of the retrofit, without any tax incentives to reduce the capital costs. A hybrid geothermal-solar plant may be eligible for subsidies such as the investment tax credit (ITC). The ITC was extended in 2016, and has a value of 30% for solar installations that have commenced construction before 2019 (Mai, Cole, Lantz, Marcy, & Sigrin, 2016). The value of the ITC then decreases to a value of 10% by 2022. The LCOE for hybrid plants with four hours of thermal storage that take advantage of the ITC are given in Table 5. The tax incentives are sufficiently large that the LCOE is quite competitive even when storage costs are high.

Table 5: Tax incentives reduce LCOE significantly, even for high storage costs. Systems include four hours of storage.

		LCOE ($ / kWh$_e$)					
		Burley, ID			Imperial, CA		
	Tax incentive %	0	10	30	0	10	30
TES cost $ / kWh$_{th}$	25	0.113	0.104	0.085	0.088	0.081	0.067
	35	0.118	0.108	0.088	0.091	0.084	0.069
	50	0.125	0.114	0.093	0.097	0.089	0.073

5. Concluding Remarks

In this paper a geothermal binary cycle is retrofitted with a solar topping steam cycle. The waste heat from the steam cycle is used to return the binary cycle to its design point. We develop design and off-design models of the geothermal plant (and verify against operational data), solar field, and topping cycle. These models account for variations in ambient temperatures and solar resource. We undertake annual simulations to evaluate the additional electricity generated and levelized cost of electricity (LCOE).

A screening study indicated that a system with a single steam turbine that acts as a topping cycle to the geothermal plant has the best performance and simplicity. The LCOE is calculated for hybrid plants located in Burley, Idaho; Reno, Nevada; and Imperial, California. The annual average ambient temperature significantly affects the performance of the geothermal plant (which uses an evaporative cooling tower), with the California plant generating the least electricity due to higher wet-bulb temperatures. However, the solar resource is greater in Imperial, CA than at the other two locations, leading to a higher quantity of additional electricity produced due to the solar field. Consequently, the LCOE, without tax incentives, of a hybrid plant in California is lower (0.118 \$ / kWh_e) than the other two locations (0.126 \$ / kWh_e at Burley, ID and 0.122 \$ / kWh_e at Reno, NV).

The sizing of the solar field is investigated, and it is found that the LCOE is minimized at solar multiples of 1.25. In a hybrid system, excess solar heat does not have to be curtailed but can be bypassed around the turbine and added directly to the geothermal plant. This reduces the quantity of energy that is curtailed, increases the optimal solar multiple to be around 1.5, and slightly decreases the LCOE.

However, this mode of operation is less efficient than extracting work at high temperatures in the solar field. Installing thermal storage allows power to be extracted at higher efficiencies at later times, and also improves the dispatchability of the plant and may enable it to take advantage of fluctuating prices. The solar multiple that minimizes the LCOE increases when thermal storage is added. Four hours of storage has an optimal solar multiple of 1.75, and eight hours has an optimal value of 2.0. We find that storage should cost less than \$30/kWh_{th} in order for the minimum LCOE to be lower than that of a hybrid plant with no storage.

We consider the impact of subsidies on the LCOE. Tax incentives such as the Investment Tax Credit reduce the capital cost between 10 % and 30 % and significantly reduce the LCOE. For instance, for a hybrid plant with four hours of storage in Imperial, CA, a solar multiple of 1.75 and a tax incentive of 30 % has an LCOE of \$0.067/kWh_e.

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