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Hybrid Solar Thermal Energy System for District Heating Application

Sertaç Akar[1][https://orcid.org/0000-0001-9598-0037], Parthiv Kurup[2][https://orcid.org/0000-0002-1735-6703], Matthew Boyd[3][https://orcid.org/0000-0003-2705-3084], and Colin McMillan[3][https://orcid.org/0000-0001-5346-478X]

[1] National Renewable Energy Laboratory, Golden, CO, USA

Abstract. Solar district heating (SDH) systems can be good alternatives to conventional systems when they are optimized with hybrid configurations and thermal energy storage (TES). In this scope, a hybrid renewable thermal energy system (RTES) model has been built combining flat plate collector (FPC) solar system with parabolic trough collector (PTC) system via a heat exchanger and coupled with TES. To undertake the hybridization of the system, System Advisor Model (SAM) software was modified, which allowed control over configurations and more accurate modelling of heat transfer between the collectors. The model is first compared to an existing hybrid solar district heating systems (DHS) system in Taars, Denmark. The results showed a good correlation with an overestimation of only 6.4% compared to most recent heat output. Then the same system configuration was modeled in different geographic locations to investigate the impact of changes in direct normal irradiance (DNI) to the heat sink thermal output of the hybrid system. The results showed that the annual net thermal power output in California, USA can be three times more than the annual net thermal power output in Taars, Denmark. Finally, multiple hybrid configurations with varying solar field sizes were simulated based on the heat demand of two different university campuses DHS. The results showed that, retrofit applications of this hybrid DHS system coupled with TES could reduce the natural gas consumption of the existing systems between 25% and 41%. The use of hybrid RTES highlighted in this paper can be extended to many more opportunities.

Keywords: Solar Thermal, Hybrid Systems, Thermal Energy Storage, District Heating

1. Introduction

Flat plate collectors (FPCs) and parabolic trough collectors (PTCs) are two examples of solar thermal technologies that have been used either as single technologies or as a hybrid for district heating applications [1]. FPCs have lower thermal efficiency than PTCs due to their higher heat losses [2]. FPCs are well-known systems for water heating but PTCs are not deployed as much. Advantages of hybrid systems for large solar heating plants and district heating are 1) maximizing the thermodynamic matching of energy outputs and 2) stepping up temperature levels where FPCs may not be able to reach. Thus, hybrid applications would be a better alternative to conventional systems. University campuses are good candidates for solar district heating (SDH) applications coupled with thermal energy storage (TES) due to their single-ownership structure, organized infrastructure, and large heat load requirements [1]–[3].

System Advisor Model (SAM) is a well-established open-source tool for modelling renewable energy systems including solar heat systems developed by the National Renewable Energy Laboratory (NREL) [4]. In SAM, solar water heating (SWH) with flat plate and evacuated tube collectors can already be modelled to evaluate the thermal yield. SAM's concentrated solar power (CSP) models for industrial process heat (IPH) can use parabolic trough and linear

Fresnel technologies to deliver heat to a heat transfer fluid (HTF), like pressurized water, molten salt, synthetic oil, or it can directly generate steam to be utilized by the industrial process. The SWH and CSP annual thermal outputs from these models can be post-processed with financial models in SAM to calculate financial metrics such as levelized cost of heat (LCOH) and net present value (NPV).

1.1. Hybrid FPC-PTC Model Development

The first step in building this hybrid model was to create the flat plate collector (FPC) model by decoupling the heat exchanger, hot water tank, supplemental electric heating, pumps, and piping models from the flat plate array in the existing SWH system model. This allows control over the series and parallel configuration and more accurate modelling of the pipe flow and heat loss between the collectors. A new HTF with 30/70 % glycol-water solution mix was added to SAM for use in the FPC array along with a heat exchanger between the FPC and PTC arrays to transfer heat from glycol-water mix to pressurized water. A heat exchanger was added between the flat plate and parabolic trough arrays to decouple the two arrays and allow more independent operation, including having the arrays use different HTFs and run at different mass flows. This allows for more efficient operation and a more accurate intermediate temperature delivered to the parabolic troughs. Decoupling the flat plate array required for an additional pump and corresponding controller. This new controller regulates the flat plate array pump's mass flow to maximize the heat exchanger`s effectiveness. The TES is an insulated tank designed to store hot pressurized water and located between the PTC array and natural boiler backup system (Figure1).

The hybrid plant sizing is done based on the desired process heat load, temperature, hours of thermal storage, mass flow constraints and the nominal temperature into and out of the FPC field. When sizing the PTC field, the process heat load dictates the total size of the solar field, the process heat temperature dictates the number of PTCs in series, and the mass flow constraints of the PTCs dictate the number of subfields. Additionally, the FPC field is sized according to the design process heat mass flow, the relatively constant process-heat outlet temperature, and the target intermediate FPC outlet / PTC inlet design temperature. The design mass flow of the collectors determines the number of FPCs in parallel and the required temperature rise from the cold inlet to the intermediate temperature determines the number of FPCs in series.

2. District Heating Case Study in Taars, Denmark

2.1. Model Comparison

The operational SDH network in Taars, Denmark supplies hot water for space heating and domestic hot water for about 850 buildings with about 1900 residents [5]. The hybrid system is composed of two solar collector fields, with 5,972 m^2 of FPCs and 4,039 m^2 of PTCs in series, coupled to two tanks of TES with a total volume of a 2,430 m^3. This SDH has been retrofitted to the existing district heating system which is composed of two natural gas boilers providing up to 9.10 megawatt thermal (MW-th) of peak power. The design principle of the hybrid system is that the FPCs preheat the return water from the district heating network from 38°C - 42°C to 70°C - 75°C and then the PTCs increase that to higher temperatures to 90°C - 95°C for the district heating network. A simplified illustration of an operating hybrid FPC-PTC SDH system coupled with TES and retrofitted to existing natural gas burners can be seen in Figure 1.

In the modelled system, A glycol-water mixture of 30/70 is used in the FPC loop and pressurized water is used in the PTC loop. The PTC system can raise the temperatures up to 150°C using pressurized water, based on end-use heat requirements. When higher temperatures are needed (i.e., 300°C) the HTF would need to be replaced with a synthetic oil such as Therminol VP-1. The SAM model was simulated for one year and its results compared to one year of operational data from the solar IPH site. The SAM weather file for Taars was developed using on-site measurements provided by Aalborg CSP from the Tylstrup weather station, which is located at 15 miles Southwest of Taars. The cumulative annual thermal energy yield of the solar field simulated through the internal NREL SAM model was 6,474 MWh-th, corresponding to an overestimation of only 6.4% compared to the 2021 annual thermal output of 6,083 MWh-th, (Table 1).

The monthly generation data is acquired from Tian et al. [5] represents the modelled case in 2016 with an annual heat generation of 4,651 MWh-th which is 23% less than the thermal generation in the Taars system in 2021. Also, the model was using weather data between September 2015 and August 2016 which has an average direct normal irradiance (DNI) of 983 kWh/m^2 per year [5], while the system modeled in SAM uses typical meteorological year (TMY) data for Tylsrup, Denmark, average annual DNI of 1,151 kWh/m^2. Thus, a modification was made to the monthly generation values presented in Tian et al. [5] to reflect the most recent site operations, generation capacity, and TMY conditions. Comparison of monthly heat generation from the modified model of Taars system by Tian et al. [5] and the newly developed SAM model are shown in Figure 2.

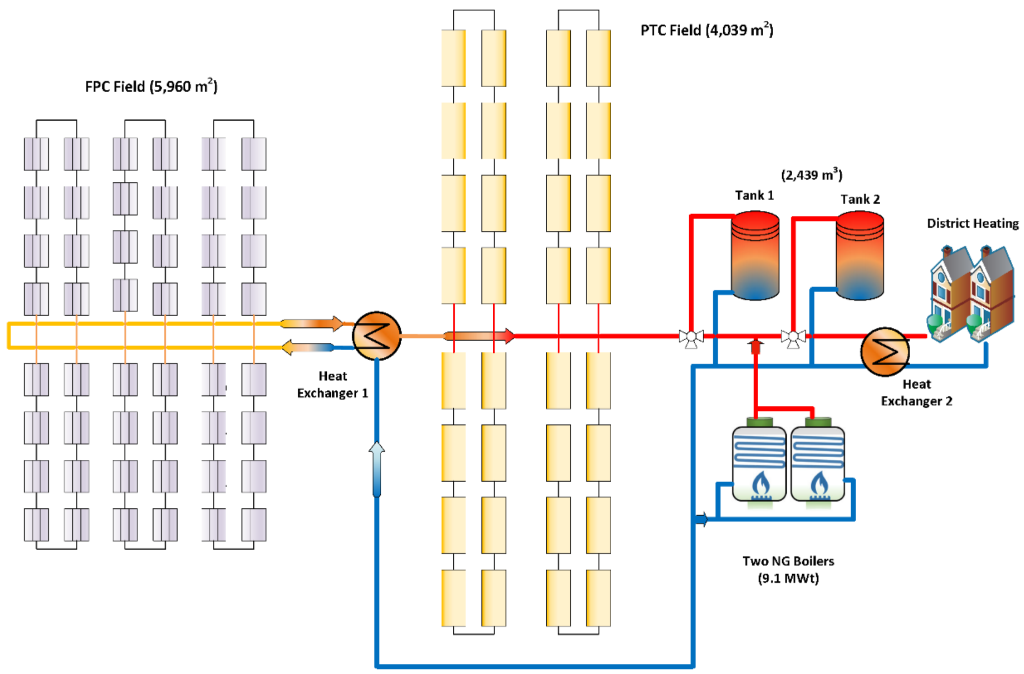

Figure 1. Simplified illustration of the modelled hybrid SDH system.

Table 1. Hybrid specification in Taars, Denmark district heating system compared to the SAM model (*the 2016 monthly generation values presented in Tian et al. [5] are improved to reflect most recent generation capacity, and TMY conditions).

Parameter	Units	2021 Operational	2015 - 2016 Modified*	SAM Modelled
Annual Heat Generation	MWh-th	6,083	6,046	6,474
FPC Field Size	m^2	5,972	5,972	5,971
PTC Field Size	m^2	4,039	4,039	4,038
HTF in FPC Loop	n/a	Glycol-Water Mix	Glycol-Water Mix	Glycol-Water Mix
HTF in PTC Loop	n/a	Pressurized	Pressurized	Pressurized
TES Tank Volume	m^3	2,430	2,430	2,417

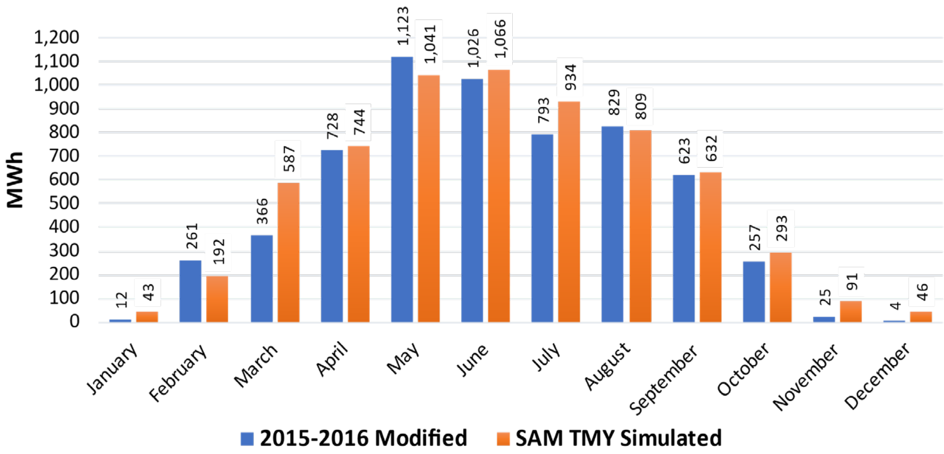

Figure 2. Comparison of monthly heat generation from modified SDH model from 2015-2016 and simulated system in SAM.

3. Parametric Analysis

Parametric analysis has been conducted to investigate the impact of inlet temperature fluctuations and changes in DNI to the heat sink thermal output of the hybrid system. First, the inlet temperatures for the FPC and PTC fields and outlet temperatures from the PTC field have been changed by 1°C increments. This results in the temperatures ranging between 38°C and 42°C for the FPC inlet. Also, the temperatures range between 70°C and 75°C for the PTC inlet, and between 90°C and 95°C for the PTC outlet. The changes in the heat sink thermal output have been monitored with respect to the change in inlet temperature. The results showed that the fluctuations in FPC and PTC inlet temperature and PTC outlet design temperature changes the annual net thermal power output between 1% and 2%.

Then, different locations in the United States have been selected to test the Taars, Denmark, hybrid SDH system configuration. The selected locations are Lancaster, CA, Tucson, AZ, Denver, CO, and Pittsburgh, PA, which have annual average DNI values of 7.93 kWh/m^2/day, 7.36 kWh/m^2/day, 6.26 kWh/m$^{2/}$day and 4.10 kWh/m^2/day respectively [6]. The changes in the heat sink thermal output have been monitored with respect to the change in DNI. The results showed that the annual net thermal power output can be as high as 17,263 MWh-th in California, which is almost three times more than in Taars (Figure 3).

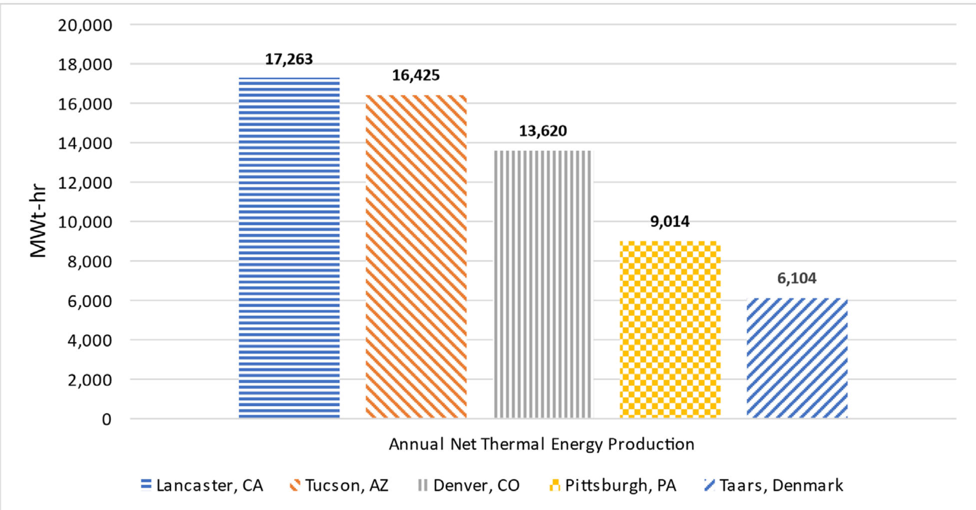

Figure 3. Comparison of the hybrid system annual net thermal energy generation for different locations.

4. SDH Potential for District Heating Systems in University Campuses

To explore the potential and test suitability of hybrid SDH system two university campuses have been selected as case studies. The first one is Cornell University which has a well-established district heating system mostly steam based but parts are already converted to liquid hot water. The goal eventually is for the whole system to operate at lower temperature hot water instead of steam. Cornell University envisions becoming carbon neutral by 2035 and recently developing of a deep geothermal system for providing low-carbon heating to its main campus in Ithaca, New York. The second one is UC Davis in California, which also has the very aggressive goal of being carbon neutral by 2025 and is currently in the process of switching from a steam heating system to a hot water heating system.

4.1. District Heating System in Cornell University

Cornell University's main campus is home to 30,000 people distributed among 14 million sq. ft. of building area in Ithaca, New York, with an annual heating demand of about 243 GWh-th per year, which corresponds to a yearly average heat demand of 28 MW-th [7]. Monthly average air temperature during the four months of winter varies between 0°C and -5°C [8]. Heating demand is concentrated in winter months, with peak heating loads over 80 MW-th occurring for about 20 days per year [7]. TMY weather data from the NRBDS data library is used for the SAM model as solar resource which gives an annual average DNI of 3.76 kWh/m^2/day for the geographic location where Cornell University`s main campus is located [7]. Current campus heating demand is predominantly supplied by burning natural gas in a combined heat and power plant and distributed with a district heating system [7]. Cornell University intents to lower its carbon footprint and has adopted an aggressive renewable energy program to replace natural gas and supply heat to the campus district heating system (DHS) [8]. Development of low-carbon and carbon-free approaches to heating are foundational pieces of Cornell University's Climate Action Plan which envisions becoming carbon neutral by 2035 [9].

The existing central energy plant with cogeneration system provides an inlet temperature of 98°C using hot water as the HTF. Thus, in Scenario 1, a 28 MW-th FPC-PTC hybrid system with 24 hours of TES, having a solar multiple of 2, has been modeled. Pressurized water is selected as the HTF since the target output temperature is 98°C, and the inlet (return) temperature is 52°C. On the FPC side a 30/70 glycol-water mix is used as the HTF which is preheated up to 70°C. In Scenario 2, an 80 MW-th FPC-PTC hybrid system with 24 hours of TES is modelled to represent peak load. In Scenario 3, a 50 MW-th FPC-PTC hybrid system with 24 hours of TES is modelled to represent a more optimal design. The results of modelled scenarios and the amount of natural gas offset in each scenario can be seen in Table 2. Monthly heat generation of all modelled scenarios with respect to the monthly heat demand of the Cornell University campus is shown in Figure 4.

Table 2. Summary of modeled scenarios for Cornell University DHS (*Surplus solar energy neither be used nor be stored based on hourly heat demand of the DHS).

Parameter	Units	Scenario-1	Scenario-2	Scenario-3
FPC Field Size	m^2	16,500	33,100	24,800
PTC Field Size	m^2	21,500	43,000	32,300
Storage Tank Volume	m^3	13,400	38,300	23,900
Capacity Factor	%	11.7	8.2	10.0
Annual Heat Generation	GWh-th	29.9	59.8	45.0
Surplus Solar Energy*	GWh-th	4.9	22.6	13.2
Natural Gas Offset	MMBTU	102,000	204,000	156,000

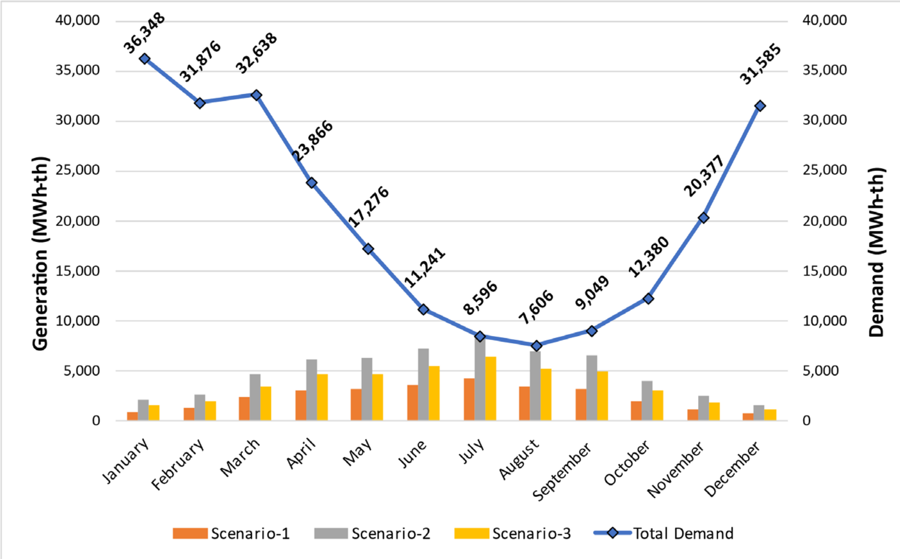

Figure 4. Comparison of Cornell University campus monthly heat demand and modelled scenarios

4.2. District Heating System in University of California (UC) Davis

UC Davis`s main campus is home to 40,000 students located at Davis, California [10]. The Central Heating and Cooling Plant (CHCP) at UC Davis is comprise of a steam generation and distribution system as well as a chilled water generation, storage, and distribution system. The purpose of the plant is to supply much of the heating and cooling needs of the buildings on campus. The steam generation system in 2012 consisted of four boilers with a combined steam generation capacity of 425,000 lb/hr (192.8 ton/hr). Recently , one boiler was not operational which reduced the total steam generation capacity to 325,000 lb/hr (147.4 ton/hr) [11]. The system also contains make-up water treatment, condensate collection, polishing, deaeration, and air emissions control where required. The existing CHCP provides steam with a temperature of 176°C to the system. Although the steam system has its benefits, in order to meet carbon neutral goals by 2025, UC Davis is currently in the process of switching from a steam heating system to a hot water heating system [12]. TMY weather data from the NRBDS data library is used for the SAM model which gives an annual average DNI of 5.27 kWh/m^2/day for the geographic location where the UC Davis main campus is located [13].

Table 3. Summary of modeled scenarios for UC Davis DHS (*Surplus solar energy neither used nor stored based on hourly heat demand of the DHS).

Parameter	Units	Scenario-1	Scenario-2	Scenario-3
FPC Field Size	m^2	12,000	17,300	14,700
PTC Field Size	m^2	26,900	40,400	32,300
Storage Tank Volume	m^3	4,050	6,080	5,060
Capacity Factor	%	31.6	31.5	30.3
Annual Heat Generation	GWh-th	57.6	86.1	69.1
Surplus Solar Energy*	GWh-th	0.9	14.3	5.5
Natural Gas Offset	MMBTU	194,000	245,000	216,000

In Scenario 1, a 20 MW-th FPC-PTC hybrid system with 24 hours of TES, having a solar multiple of two, 150°C design PTC outlet temperature, and return temperature of 40°C has been modelled. On the FPC side a 30/70 glycol-water mix is used as the HTF which is preheated up to 70°C. In Scenario 2 and Scenario 3, 30 MW-th and 25 MW-th FPC-PTC hybrid systems with 24 hours of TES are modelled. The simulation results and the amount of natural gas offset in each scenario can be seen in Table °4. Monthly heat generation of all modelled scenarios with respect to monthly heat demand of the UC Davis campus is shown in Figure 5.

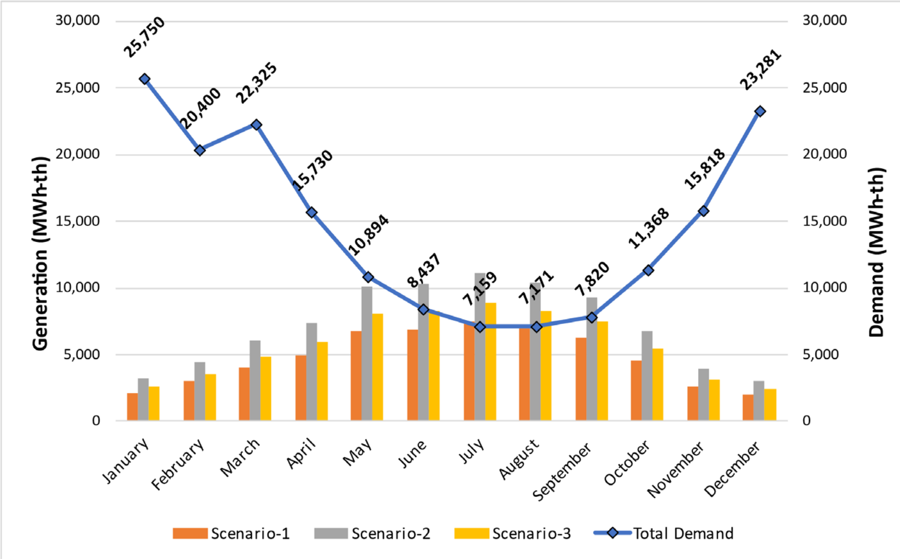

Figure 5. Comparison of UC Davis campus monthly heat demand and modelled scenarios.

5. Discussions

A SDH system coupled with a TES can cover most of the heat demand in summer months and would have natural gas offset up to 25% in winter months. Hybrid configurations of FPCs and PTCs would maximize the advantages of both systems in different enthalpy levels. The SAM software is a suitable platform for further developing the hybrid simulation models. Improvements are implemented in refactoring component models for sharing across systems, and generalizing integration methods, control and optimization for subsystems and standardizing interfaces would allow SAM to design hybrid systems as previously described.

The hybrid FPC-PTC system modeled in SAM has been compared with the existing SDH system in Taars, Denmark with an 6.4% overestimation based on an annual heat generation of 6,083 MWh-th. Monthly generation of the modelled system in SAM had very good correlation with Taars SDH heat generation in summer months. However, the monthly heat generation in winter months (November-December and January) was exceptionally high due to the difference in 2015-2016 meteorological year DNI compared to the Tylstrup TMY DNI which is used in the SAM model.

The results of the parametric analysis shown in Figure 3 also indicates that the return temperature to the FPC is very important for increasing the thermal efficiency of the hybrid system. This is due to the higher efficiency of FPCs at lower temperatures. In addition to that, increasing the PTC output temperature from 90°C to 150°C while using pressurized water as the HTF increases efficiency and the capacity factor of the system. Another important factor is of course geographic location of installed system. When same size system is installed in higher DNI locations more annual heat can be generated.

The size of the hybrid SDH system in Taars was reaching up to 9 MW-th with back-up of two NG boilers, which was used to validate the hybrid FPC-PTC system modelled in SAM. However, sizes of the hybrid SDH systems modelled for Cornell University and UC Davis ranged between 20 MW-th and 80 MW-th due to higher heat demand in each campus. This raised the issue of surplus energy during the peak DNI hours of the winter days, and most of the summer days. This also raised the issue of land requirements for the solar field. As a solution to oversized systems and surplus thermal energy, seasonal storage could be utilized.

Combining SDH with geothermal energy, as a source of energy [7] or seasonal TES [2], where resources are available, could also increase the amount of natural gas offset in winter months. Cornell University is currently developing a deep geothermal system, also called Earth Source Heat (ESH), for providing low-carbon heating to its main campus in Ithaca, New York, and helping to become a carbon-neutral university by 2035. For this purpose, a 10,000 ft (3,048m) deep observation well is drilled in 2022 which will enlighten the outstanding technical questions about the geothermal resource.

The natural gas offset reaches up to 204,000 MMBTU for the Cornell University campus which correspond to 25% of the annual heat demand and 294,000 MMBTU for the UC Davis campus which correspond to 41% of the annual heat demand. Even though these are significant savings in terms of operational expenses they require large solar fields. Thus, the payback periods for these systems are not expected to be short. To evaluate techno-economic feasibility more detailed economic model is required. In future work a techno-economic analysis will be conducted to calculate parameters like the LCOH, NPV, and payback period. Recent cost for a standalone FPC system can be approximately $400/kW [14] depending on the systems size. The average cost of a standalone PTC system is $560/kW [6]. The hybrid design with the optimum solar field size and higher efficiency is expected to have a lower installed cost and LCOH than the standalone systems.

Data and Related Material Availability Statement

The data supporting the results of this article is based on is restricted third-party data. The SAM module used in this research is not available in public version of the SAM software as of 2022.

Competing Interests

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Author Contributions

Statement on authors' contributions according to the CreDIT guidelines are presented as; Sertaç Akar (Formal analysis, data curation, methodology, validation, visualization, writing original draft), Parthiv Kurup (Funding accusation, conceptualization, methodology, supervision, writing, review, and editing), Matthew Boyd (Software, formal analysis, validation). Colin McMillan (Supervision, writing, review, and editing).

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