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Assessment of CST Systems for Applications in Industrial Process Heating

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Abstract

Australia enjoys abundant insolation and large areas of the country have dry climate, resulting in a high potential for solar plant deployments. However, only a small percentage of Australia's energy use is provided by solar energy. The use of solar energy for supplying domestic hot water and generating electricity using distributed photovoltaic panels has been increasing in recent years; however, there have been very few applications of large scale solar thermal energy for industrial use. This contrasts with increasing application of concentrating solar thermal (CST) systems for large scale generation of electricity over the past few years internationally. One of the most important features of CST systems is the fact that a thermal storage system can be integrated into the plant design to allow high capacity factors to be achieved. Therefore, CST may be an appropriate technology for replacing fossil fuels in industrial processes that require heat input either consistently or as part of a scheduled cycle. This study is a follow-up to an earlier study on the Australian industry energy usage that introduces assessment for specific sites to examine the potential for CST deployment and develops a techno-economic methodology to provide an insight into economic viability of central receiver systems for generating process heat, given the current and future natural gas prices.

1. Introduction

Concentrating solar thermal systems have been the subject of significant commercial development for the generation of electricity in recent years. One of the significant advantages of this technology over other renewable systems is the capability to incorporate a thermal storage system. Thermal storage system addresses the intermittent nature of solar energy and allows for high capacity factors; therefore, CST with thermal storage appears to be an appropriate technology to replace fossil fuels in industrial process heat provision applications.

This study develops a techno-economic methodology to provide an insight into economic viability of central receiver systems for generating process heat in the context of Australian climate and economic conditions. Three sizes of system (i.e. 25, 70, and 250 MW_t) with two tank molten salt storage systems with capacities ranging from 1 to 19 hours are considered and their cost competitiveness when considering current and future natural gas prices are assessed.

2. Methodology

This paper builds on a study on the Australian industry energy usage from the viewpoint of CST application potential (Beath, 2012). It provided a breakdown based on geographical location, industry type, process temperature and magnitude of energy consumption. Two constraints were imposed to reduce the number of industrial sites to those that appear more appropriate for the technology deployment. Firstly, only regions with moderate to very high solar availability were considered. These areas are identified by their approximate DNI ranges as follows: very high solar availability region where annual DNI covers the range of 2500-2700 kWh/m^2, high solar availability region with DNI within the range of 2300-2500 kWh/m^2, and moderate solar availability region with the DNI range of 2100-2300 kWh/m^2. In addition, industrial sites were also reduced to the ones that have demands in the range 25 to 250 MW thermal. Figure 1 shows the reduced set of industrial sites.

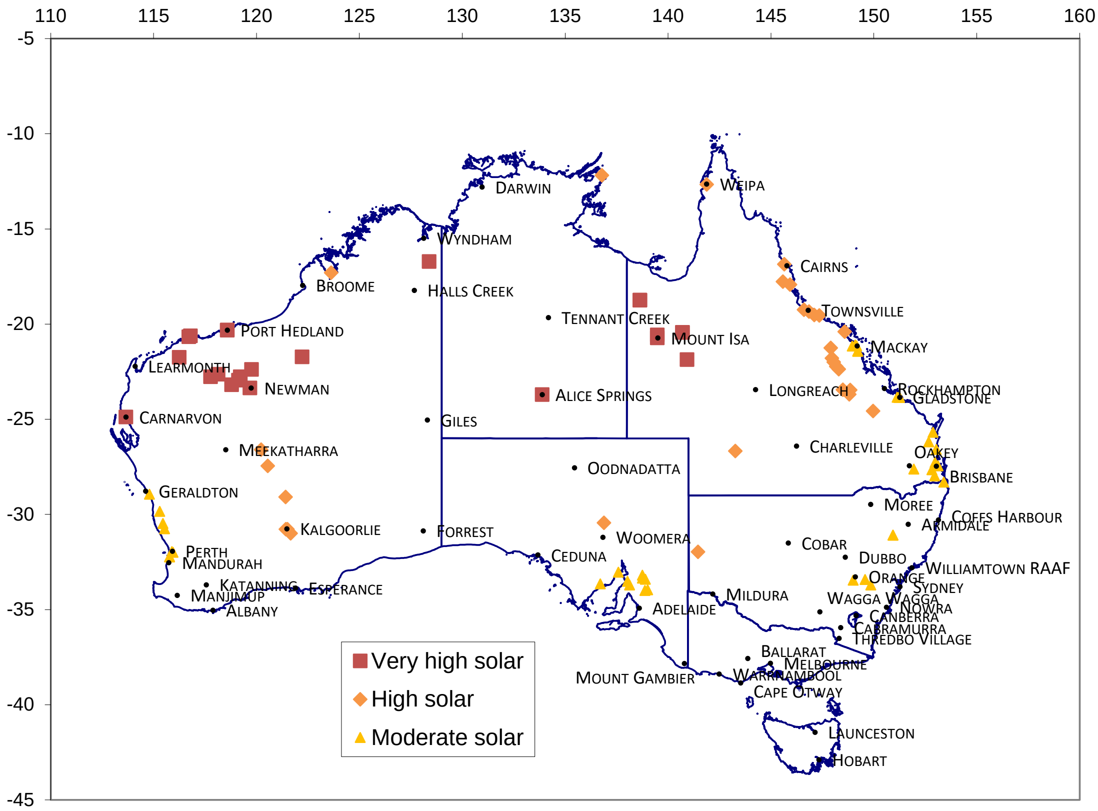

Figure 1. Summary of the appropriate sites for CST deployment

Characteristic temperatures for the majority of these sites are within the moderate (300-800 °C) and high (800-1300 °C) temperature ranges (Beath, 2012). The typical molten salt temperature range in the conventional central receiver systems is 290-574 °C. It appears to provide a good match to moderate temperature processes, although achieving the upper part of the temperature range will require the use of supplementary heating. For applications in the high temperature range the solar plant could be considered as most appropriate for pre-heating of fluids only, but this could result in significant reductions in the use of other energy.

To simplify the analysis, a representative site for each solar intensity region was selected; these are Learmonth (annual DNI of 2767.8 kWh/m^2) for the very high solar area, Kalgoorlie (annual DNI of 2463.7 kWh/m^2) for the high solar area and Rockhampton (annual DNI of 2058.9 kWh/m^2) for the moderate solar area. Figure 2 shows the monthly DNI at these sites for the Representative Meteorological Year (RMY) (EnergyPlus, 2016).

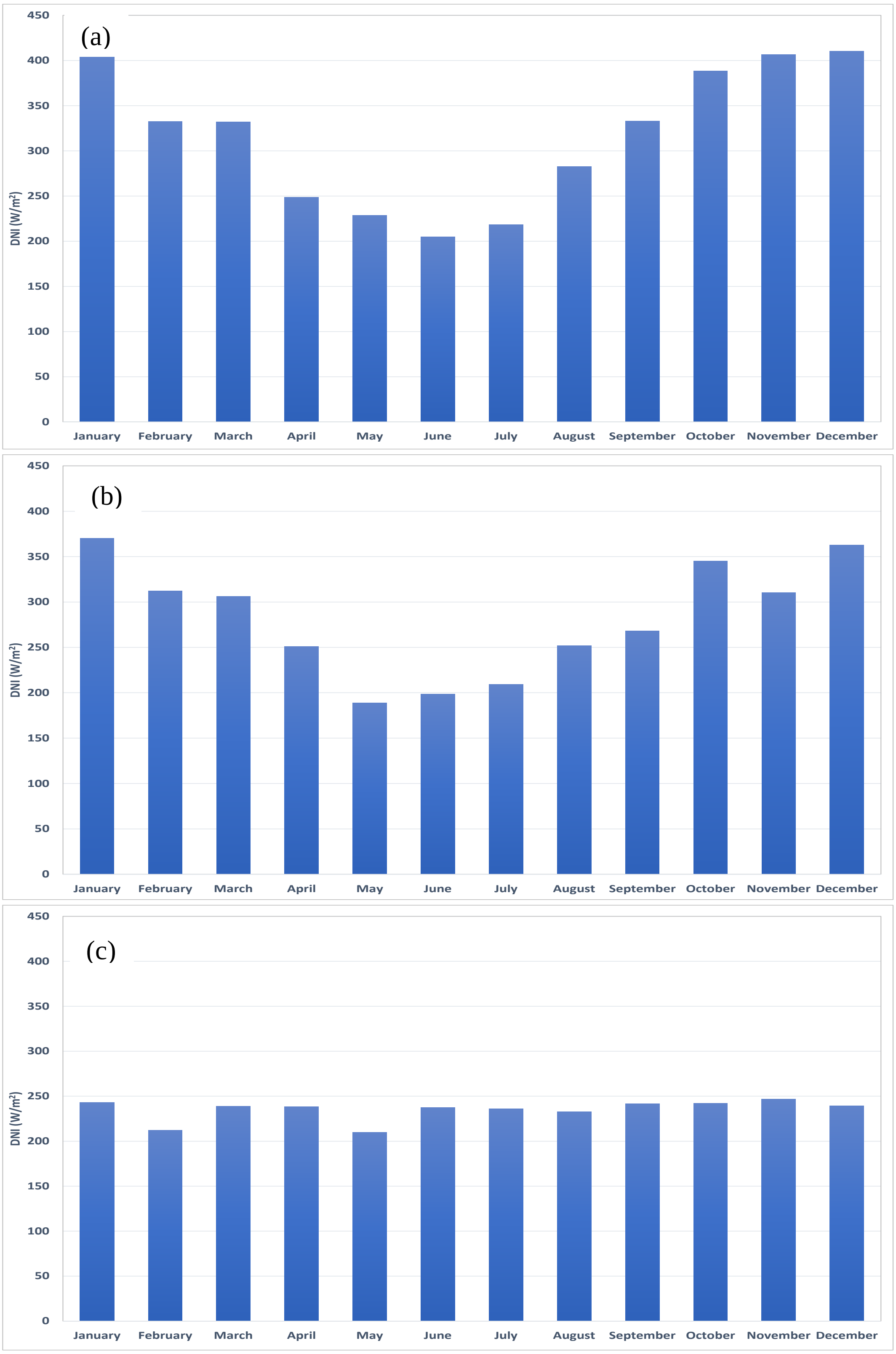

Figure 2. Monthly DNI for RMYs: a) Learmonth; b) Kalgoorlie; c) Rockhampton

NREL's SAM (version 14.3.2016) was selected to perform the techno-economic optimization and simulation of CST plants. Three solar tower systems with the design thermal sizes of 25, 70, and 250 MW_t which also incorporated two tank molten salt thermal storage system with the capacities ranged from 1 to 19 hours were simulated and optimized using RMY data for the three characteristic sites. Table 1 lists major technical characteristics which were fixed for all the systems and sites.

Table 1 Main technical specifications

Design receiver HTF outlet temperature	574 °C
Design receiver HTF inlet temperature	290 °C
HTF type	Salt (60% $NaNO_3$ 40% KNO_3)
Receiver type	External
Number of panels	20
Tube outer diameter	40 mm
Tube wall thickness	1.25 mm
Maximum receiver flux	1000 kW_t/m^2
Heliostat width	12.2 m
Heliostat height	12.2 m
Ratio of reflective area to profile	0.97
Heliostat reflective area	144.375 m^2
Mirror reflectance and soiling	0.9
Heliostat availability	0.99
Storage type	Two tank molten salt system
Tank height	20 m
Tank fluid minimum height	1 m

An exhaustive analysis of international and Australian studies led to a detailed capital cost and O&M cost breakdown of a molten salt central receiver plant with 294 MW_t of thermal capacity and 4 hours of two tank thermal storage as the base case plant (Meybodi and Beath, 2016). Table 2 shows the SAM costing data for the base case plant used in this study.

Table 2 SAM costing data for the base case

Item	Value	Unit
Site improvements	20	$\$/m^2$
Heliostat field	180	$\$/m^2$
Balance of plant	350	$\$/kW_e$
Storage	37	$\$/kWh_t$
Fixed tower cost	3,117,043.67	$
Tower cost scaling exponent	0.0113	-
Receiver reference cost	71,708,855	$
Receiver reference area	879.8	m^2
Receiver cost scaling exponent	0.7	-
Contingency	7	%
EPC and owner cost	11% of the direct capital cost	-
O&M cost	26.8	$\$/kW_t$-yr

Microsoft Excel has been used to create a cost model to estimate capital and O&M costs for other sizes of the system and provide a detailed system cost breakdown. This model uses conventional engineering assessment techniques to estimate the cost of a plant component based on operating conditions and scale. It also exchanges data with SAM automatically which allows for automated cost estimation for a specific plant design and therefore cost and performance optimizations are performed with minimal manual interactions. Levelized Cost of Heat (LCOH, c/kWh), as defined by Equation (1), was selected to analyze the systems from an economic point of view:

$$LCOH = \frac{\sum_{t=1}^{n} \frac{CAPEX_t + OPEX_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{H_t}{(1+r)^t}} \quad (1)$$

Where CAPEX is total capital cost ($), OPEX is the operational and maintenance cost ($/y), F is fuel cost ($/y), n is life of project (3 years of construction and 27 years of operation), r is the discount factor (0.07), H is the produced heat (kWh/y), and t is the year of the project. SAM's scripting language was used to develop a code to automate optimization of solar multiples for a given thermal capacity for the storage sizes within the range of 1 to 19 hours. After finding optimum solar multiples, the optimized values were used to optimize the plant and simulate its performance. Finally, the costing and performance data were used to calculate LCOH.

3. Results and discussion

Figure 3 depicts LCOH in $/GJ for the three design thermal capacities versus the thermal storage sizes within the range of 1 to 19 hours. As evident from the figure, the plant's economic performance depends on the scale of application and for all studied sites the 250 MW_t system is the most economical option followed by 70 MW_t and 25 MW_t systems. Performance is also influenced by solar availability in a consistent manner. Learmonth is the most appropriate area to deploy the CST plant. Kalgoorlie is the second most suitable area and Rockhampton is the least appropriate area. For all the sites, a 250 MW_t system with 13 hours of storage is the most cost effective option with LCOH values of $11.2/GJ, $14.0/GJ, and $15.6/GJ for Learmonth, Kalgoorlie, and Rockhampton, respectively.

It is important to compare the cost of solar heat provision with current and future estimates for provision of conventional energy sources, typically natural gas, for industrial applications. A consulting company was commissioned in 2015 by the Australian government to review gas price trends. They prepared a report (Oakley Greenwood, 2016) which provided estimates for gas prices, the components that constituted prices, and historical trends (from 2002 to 2015) for Australian states and territories. This report found that gas prices for large industrial customers (with gas consumptions greater than 1 PJ per year) had been steadily rising in all states except Western Australia, where prices peaked in 2009 and had been decreasing ever since. In 2015, delivered gas prices ranged from $5.68/GJ in Victoria to $11.97/GJ in North West Queensland which is in the very high solar availability area. Wholesale gas costs were the largest proportion of large industrial customer gas prices (from 71 % of the delivered gas price in Tasmania to 94% in Brisbane) and Australian Energy Market Operator has predicted that the delivered wholesale cost of gas will increase by 48% by 2036 (AEMO, 2016).

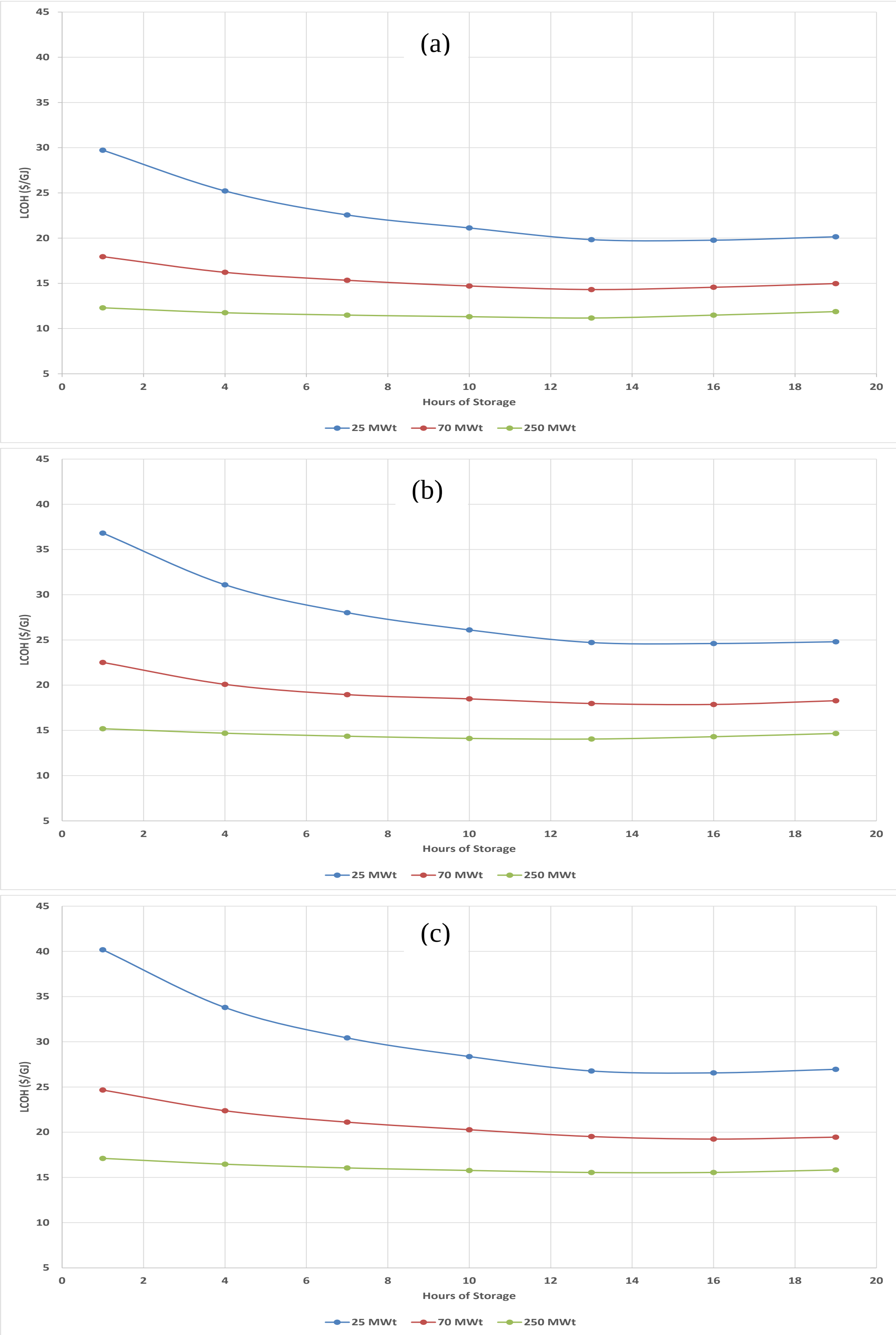

Figure 3. LCOH versus the thermal storage capacity: a) Learmonth; b) Kalgoorlie; c) Rockhampton

The results show that 250 MW_t systems with appropriate storage size are already cost competitive in the areas with high solar availability. In addition, CSP system costs are decreasing as a result of new deployment and the experience gained from operating existing plants. This along with rising natural gas prices and poor availability of fuels in some parts of the country indicate the promising future of the technology.

4. Concluding remarks

This study indicates that currently available technology could be applied in a commercially competitive manner at sites with high to very high solar availability for industrial process heat provision applications. However, this would require large CST plants with large storage capacity and this size of industrial application typically enjoys discounted fuel prices. Therefore, it appears that cost reductions in CST technologies, in particular for smaller scale systems, will be required to make CST technology a cost effective option in the absence of significant increases in the cost of fossil fuels.

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