Open Access Journal

Journal of Power Technologies 93 (3) (2013) 178–184

journal homepage:papers.itc.pw.edu.pl

Optimal sizing of modular air-cooled condensers for CSP plants

Andreas Poullikkas[*,a], Ronan Grimes[b], Edmond Walsh[b], Ioannis Hadjipaschalis[a], George Kourtis[a]

[a] *Electricity Authority of Cyprus*
P.O. Box 24506, 1399 Nicosia, Cyprus
[b] *University of Limerick, National Technological Park*
Plassey, Limerick, Ireland

Abstract

In this work, a parametric optimization analysis of various innovative modular air-cooled condenser systems is carried out in order to identify the optimum system configuration and size to be used as the cooling system in a 50MWe parabolic trough concentrated solar power (CSP) plant. The optimization analysis is conducted individually on a total of 17 different configurations and on a total of 8 different condenser sizes for each configuration. The results identify the optimum air cooled condenser configuration and size that can achieve the minimum CSP plant electricity unit cost.

Keywords: Air cooled condensers, Dry cooling, Solar thermal power plants, CSP, Renewable energy sources, Energy policy

1. Introduction

Current concentrated solar power (CSP) plants utilize water or air cooled condensers in a conventional Rankine cycle for electricity generation. The condenser performance is a key factor affecting the generation efficiency of the plant since it determines steam output temperature and pressure and thus the total amount of work done by the steam turbine [1]. The utilization of water cooled condensers, although effective, is constrained by the need for water availability in the immediate plant location. On the other hand, conventional air-cooled condensers, which do not necessitate the presence of a water source, are not as effective because they cannot maintain optimum condenser pressure and temperature and are unresponsive to daily variations in ambient temperature. This may translate to increased fan power consumption and lower plant efficiency [1–6].

In order to overcome the technical limitations of conventional air cooled condensers, the MACCSol research project [7], partly funded by the European Commission, provides an innovative industry solution through a new dry cooling approach for multi-MWe sized CSP plants. The consortium of project partners consists of three universities and four industrial partners. The universities are the University of Limerick in Ireland, the University of Erlangen in Germany and the Universita Degli Studi di Perugia in Italy. The industrial partners involved are R&R Mechanical Ltd. in Ireland, Torresol Energy Investments Ltd. in Spain, AuBren Ltd in Ireland and the Electricity Authority of Cyprus. The primary objective of the MACCSol project is the development and

*Corresponding author. Parts of this work were undertaken while the author was a Visiting Professor in the Department of Mechanical Engineering, College of Engineering, American University of Sharjah, PO Box 26666, Sharjah, United Arab Emirates

Email address: mspoul@ucy.ac.cy (Andreas Poullikkas*)

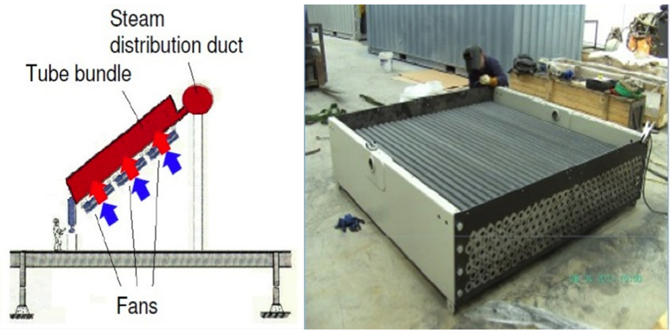

Figure 1: Typical MACC module arrangement (left) and tube bundle (right)

verification of an innovative modular air cooled condenser (MACC). If successful, this innovative technology will remove a significant barrier to the deployment of CSP plants in desert and arid areas and thus facilitate the EU in achieving its 2020 renewable energy contribution targets [8–10]. It will also ultimately enable CSP plants to increase net power output and reduce costs compared to existing dry cooled plants [11]. The completed MACC system will incorporate sensors that will detect changes in temperature and ambient wind, and fan flow rate and control algorithms, which will communicate with these sensors to continuously vary fan speed. It will therefore maintain optimum condenser pressure and temperature irrespective of ambient conditions. As a result, steam turbine outlet conditions will always be optimized, thus maximizing power output and reducing operating costs. Also, because the MACC system will be a modular design, installation and maintenance costs will be significantly reduced.

Prior to its commercialization, the MACC system performance first needs to be monitored and optimized at both module and system level. The optimization process involves numerical simulations, analytical modeling, physical scale modeling and measurements on full scale prototypes. The effects of all design options are to be assessed using thermodynamic models, while techno-economic modeling will assess the life time cost implications of various design options of MACC systems. Finally, to prove the merits of the optimized MACC design, full scale testing in an operational steam power plant will be performed [7]. A typical MACC module, with a length and width of 2 m by 2 m, is shown in Figure 1. The module is basically made up of one or more 1 m diameter fans blowing air either in induced or forced draft mode across an array of condenser tubes, located in the tube bundle section of the module, shown in Figure 1 (right) through which the output steam of the turbine flows. The optimum MACC system will consist of multiple modules, the exact number of which needs to be identified. In addition, where a variety of MACC finned tube geometries are being considered, the optimum MACC system configuration will be different for each tube geometry.

In this work, a parametric optimization analysis of various MACC system configurations and sizes is performed in order to identify the optimum MACC system configuration and size to be used as the cooling system in a 50 MWe parabolic trough CSP plant. The optimization analysis is conducted individually on a total of 17 different MACC system configurations [12]. The optimum MACC system configuration and size is to be identified by investigating for each configuration the optimum trade-off between increased operating costs associated with high MACC system fan speeds and increased capital costs, associated with the MACC system's larger heat transfer area, which is proportional to the number of MACC modules.

In section 2, the methodology and the software optimization tool used for the parametric optimization analysis of the MACC system configurations and sizes are described and the scenarios investigated are presented. The results of the optimization analysis are discussed in section 3, while the conclusions are summarized in section 4.

2. Methodology and simulation procedure

In order to identify the optimum MACC system configuration and size in terms of operating conditions, the analysis is conducted individually on 17 MACC system configurations with different finned tube geometries, namely MACC system configuration A through to configuration Q. For the purposes of this analysis, the operation of the CSP plant is simulated and the electricity unit cost is calculated based on the following algorithm: (a) calculation of solar radiation in the plane of the parabolic trough solar field, (b) calculation of electrical energy delivered by the solar thermal plant, (c) calculation of system losses, (d) calculation of electrical energy delivered to the grid, (e) calculation of required area for parabolic trough solar field, (f) calculation of required area for the installation of the solar thermal power plant and (g) calculation of electricity unit cost assuming that the initial investment year is year 0, the costs are given in year 0 terms, thus any inflation rate (or escalation rate) is applied from year 1 onwards and the timing of cash flows occurs at the end of the year [13].

In order to perform the simulations required for the above optimization analysis, the IPP v2.1 software tool is employed [14]. This user-friendly software tool can be used for the selection of appropriate least cost power generation technology in competitive electricity markets. The software takes into account capital cost, fuel consumption and cost, operation cost, maintenance cost, plant load factor, etc. All costs are discounted to a reference date at a given discount rate. Based on the above input parameters for each candidate technology the algorithm calculates the least cost power generation configuration in real prices and the ranking order of the candidate schemes. The technical and economic parameters of each candidate power generation technology are taken into account based on the cost function:

$$min\left(\frac{\partial c}{\partial k}\right) = min\left\{\frac{\sum_{j=0}^{N}\left[\frac{\frac{\partial C_{Cj}}{\partial k}+\frac{\partial C_{Fj}}{\partial k}+\frac{\partial C_{OMFj}}{\partial k}+\frac{\partial C_{OMVj}}{\partial k}}{(1+i)^j}\right]}{\sum_{j=0}^{N}\left[\frac{\frac{\partial P_j}{\partial k}}{(1+i)^j}\right]}\right\} \tag{1}$$

where c is the final cost of electricity in €/kWh, in real prices, for the candidate technology k, C_{Cj} is the capital cost function in €, C_{Cj} is the fuel cost function in €, C_{OMFj} is the fixed O&M cost function in €, C_{OMVj} is the variable O&M cost function in €, P_j is the total electricity production in kWh, $j = 1, 2, \ldots N$ is the period (e.g., years) of installation and operation of the power generation technology and i is the discount rate. For the purposes of this analysis, for the simulation of CSP technologies, the fuel cost function in Equation (1) is set to zero. The least cost solution is calculated by:

$$least\,cost\,solution = min\left[\frac{\partial c}{\partial k}\right] \tag{2}$$

During the simulations procedure the following financial feasibility indicators based on the individual case examined may be calculated: (a) electricity unit cost or benefit before tax (in €/kWh), (b) after tax cash flow (in €), (c) after tax NPV (net present value: the value of all future cash flows, discounted at the discount rate, in today's currency), (d) after tax IRR (internal rate of return: the discount rate that causes the NPV of the project to be zero and is calculated using the after tax cash flows. Note that the IRR is undefined in certain cases, notably if the project yields immediate positive cash flow in year zero) and (e) after tax PBP (payback period: the number of years it takes for the cash flow, excluding debt payments, to equal the total investment which is equal to the sum of the debt and equity) [14].

In order to identify the optimum MACC system size for each of the 17 configurations (A to Q), input data were provided for sizes ranging from 200 to 1600 modules in steps of 200 modules for each MACC system configuration. In addition, since the MACC system would be integrated as the main cooling system in a 50 MWe CSP parabolic trough plant, an annual DNI factor of 2000 kWh/m^2 is used for the analysis. Throughout the simulations, a typical discount rate of 6% is assumed. In order to calculate the after-tax cash flows and after-tax financial indicators a single 10% income tax rate is assumed that is constant throughout the project life and applied to net income. Also, the economic life of the CSP plant is assumed at 20 years. The simulations do not consider any feed-in tariff or other subsidy scheme or any income from the Emission Trading Scheme (ETS) trading.

3. Results and discussion

The results concerning the MACC system fan energy consumption are shown in Figure 2. Clearly, as the size of each MACC system configuration increases, the fan consumption decreases reflecting the increased heat rejection due to the larger heat transfer area of the MACC.

In order to identify the gross output power and the associated condenser heat rejection requirements of a typical 50 MWe steam power plant, the Thermoflow 21 software package was used and specifi-

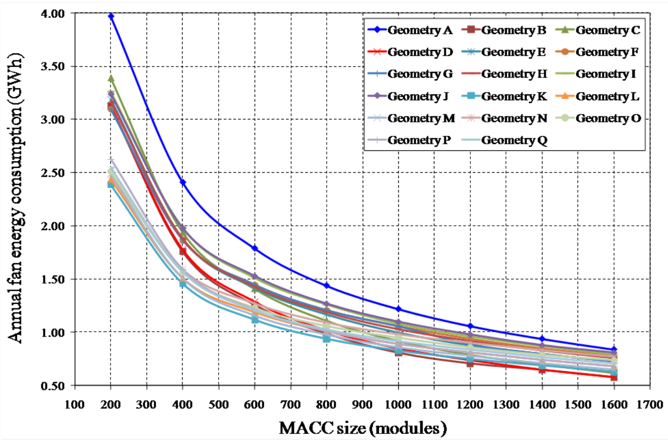

Figure 2: Annual fan energy consumption

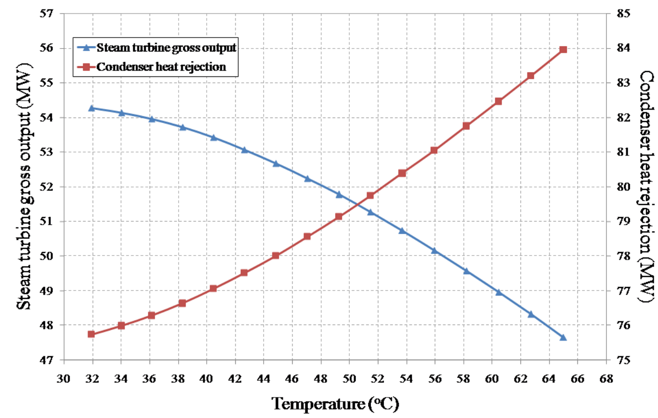

Figure 3: 50 MWe turbine gross output and heat rejection versus steam outlet temperature

cally the Steam Pro 21 and the Steam Master 21 software. In order to provide a comprehensive analysis of the variability of turbine gross output power and condenser heat rejection requirements as a function of turbine outlet steam temperature, and therefore as a function of ambient temperature levels, the turbine outlet steam temperature was varied in 16 steps, across a temperature range of 33°C between 32°C and 65°C [12]. The results of the analysis are shown in Figure 3. The annual gross energy production of the CSP plant was estimated based on the results of the above thermodynamic analysis, by considering the number of expected hours of operation of a CSP plant and the respective DNI levels at each temperature level across these operating hours.

The estimated annual gross energy production of the CSP plant is shown in Figure 4 and the estimated annual net energy production is illustrated in Figure 5.

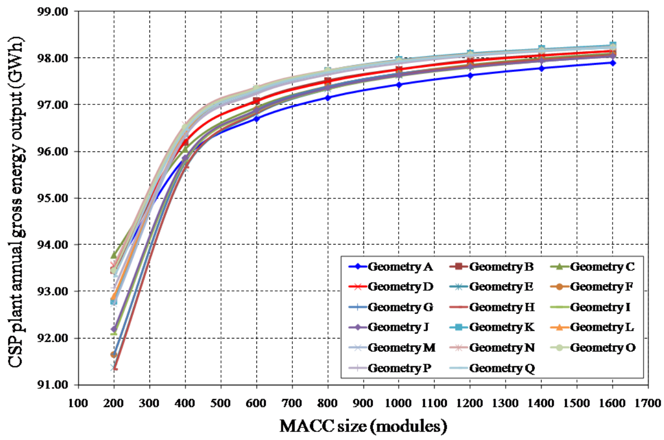

Figure 4: Annual CSP plant gross energy output

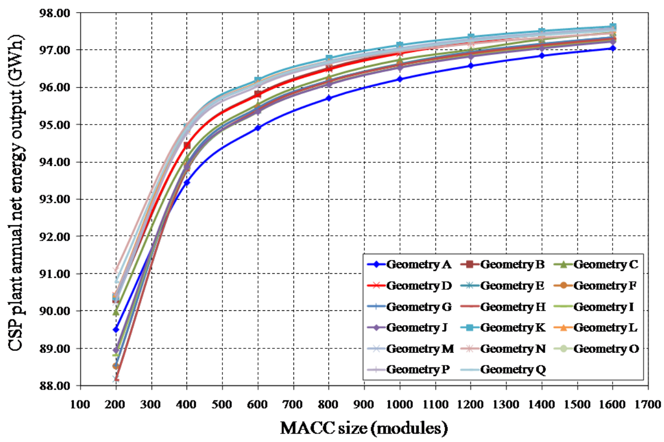

Figure 5: Annual CSP plant net energy output

The results of the analysis concerning the electricity unit cost of the CSP plant as a function of MACC system (configurations A to Q) size are shown in Figure 6. Clearly, as the size of the MACC system increases, the cost of electricity of the plant decreases to reflect the increases in net electricity generation by the CSP plant.

However, after a specific MACC size is reached, which is considered to be the optimum size, the electricity unit cost begins to rise reflecting the fact that the gains achieved in net electricity generation are now offset by the increases in MACC system capital cost. The optimum MACC system size is the size where the electricity unit cost of the CSP plant is at the minimum [12, 15].

Comparing across most MACC system sizes, configurations B and D seem to exhibit the lowest elec-

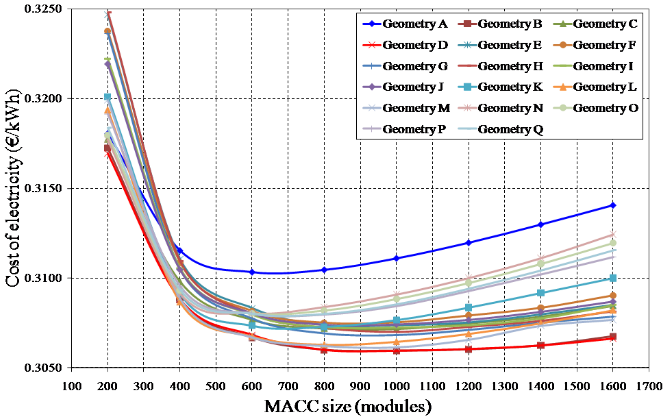

Figure 6: Overall comparison of CSP plant cost of electricity for different MACC sizes

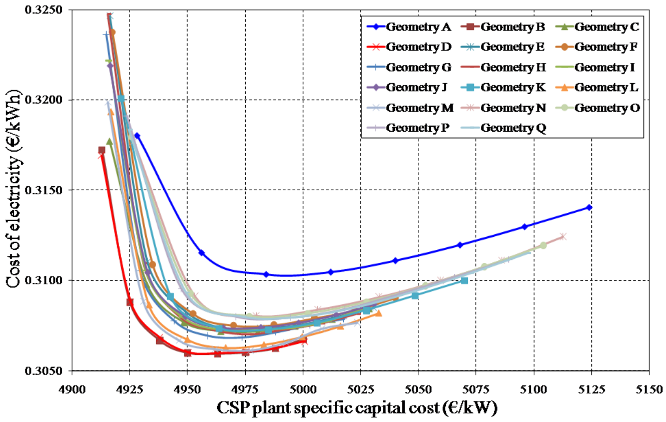

Figure 7: Overall comparison of CSP plant cost of electricity using different MACC geometries as a function of CSP plant specific capital cost

tricity unit costs, while configuration A the highest. In fact, the larger the MACC system size, the bigger the difference is between the CSP plant electricity unit cost achieved with MACC system configuration A and with configurations B or D.

The results of the analysis concerning the cost of electricity of the CSP plant as a function of CSP plant specific capital cost, in €/kW, are shown in Figure 7. The results are similar to the results above. Specifically, as the CSP plant specific capital cost increases, reflecting an increase in the size of the MACC system, the cost of electricity of the plant decreases to reflect the increases in net electricity generation by the CSP plant. After a specific CSP plant capital cost is reached, which is considered to be corresponding to the optimum size, the electricity unit cost begins to rise reflecting the fact that the gains achieved in net electricity generation are now offset by the increases in MACC system specific capital cost. Clearly, configurations B and D on the one hand and configuration A on the other hand set the lower and higher electricity unit cost value boundaries respectively. In fact, comparing across the whole range of CSP plant specific capital costs, configurations B and D seem to consistently exhibit the lowest electricity unit costs across all 17 configurations, while configuration A the highest [12, 15].

Table 1: Candidate technologies technical parameters

MACC Geometry	Optimum MACC size, modules	Minimum CSP plant cost of electricity, €/kWh
A	645	0.310297
N	585	0.308023
O	625	0.308001
Q	663	0.307955
P	689	0.307937
F	919	0.307449
J	949	0.307324
K	697	0.307249
E	981	0.307230
I	969	0.307198
C	884	0.307155
H	971	0.307024
G	955	0.306797
L	884	0.306294
M	945	0.306107
B	964	0.305929
D	976	0.305873

An overall comparison of the minimum CSP plant electricity unit cost and MACC system optimum size, for each of the MACC system configurations, is tabulated in Table 1. It is clear that the MACC system configuration that can achieve the minimum CSP plant electricity unit cost is configuration D, with a minimum electricity unit cost of 30.587 €c/kWh at a MACC size of 976 modules, followed by configuration B with a minimum electricity unit cost of 30.593 €c/kWh at a MACC size of 964 modules. Other configurations that can achieve lower minimum electricity unit costs are geometries M and L.

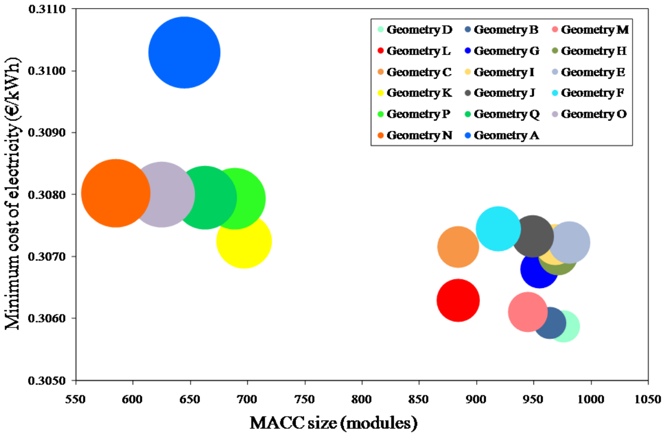

Figure 8: Overall comparison (bubble size reflects capital cost per module in €)

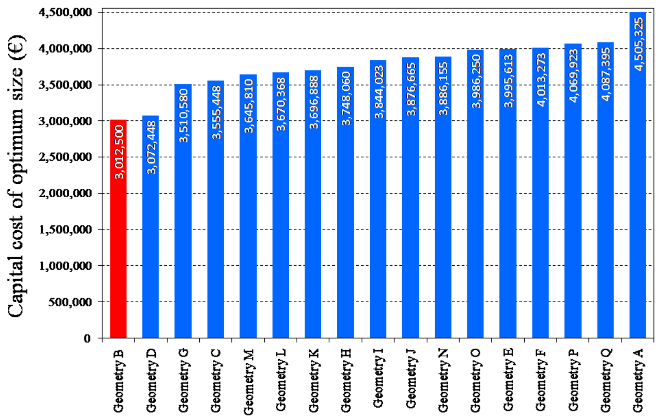

Figure 9: Capital cost for manufacturing the optimum size of each geometry

The minimum electricity unit cost achieved by prototype configuration A is by far the highest: 31.030 €c/kWh at a size of 645 modules.

Finally, in the bubble chart depicted in Figure 8 a comparison of each configuration in terms of its (a) identified minimum CSP plant electricity unit cost (y-axis), (b) corresponding optimum MACC system size (x-axis) and (c) capital cost per module (indicated by the bubble size), is shown. It is clear that the configurations which can achieve lower minimum CSP plant electricity unit costs do so at larger optimum MACC system sizes ranging from 900–1000, as for example configurations D and B.

In addition, these configurations have typically lower capital costs per module, illustrated by their smaller bubble size, compared to the configurations that have smaller optimum MACC system sizes. In fact, configurations D and B not only provide the lowest minimum CSP plant electricity unit costs but, as shown in Figure 9, which presents the optimum size capital cost for each configuration, need the lowest capital costs to manufacture at their optimum system size.

4. Conclusions

In this work, a parametric optimization analysis was carried out using the IPP v2.1 software package for the identification of the optimum configuration and size of a MACC system to be integrated in a 50 MWe CSP parabolic trough plant. A total of 17 different configurations and a total of 8 MACC sizes/scenarios per configuration were investigated in order to determine the optimum MACC system, which would essentially provide the lowest electricity unit cost for the CSP plant. Based on the input data and assumptions made, the optimization analysis shows that the CSP plant electricity unit cost decreases with increasing MACC system size, up to the optimum size, where the electricity unit cost reaches its minimum value. Beyond this size, the electricity unit cost starts to increase reflecting the increases in MACC system capital cost. An overall comparison of the minimum CSP plant electricity unit cost and MACC system optimum size, for each of the 17 MACC system configurations, shows that the MACC system configuration that can achieve the minimum CSP plant electricity unit cost is configuration D, with a minimum electricity unit cost of 30.587 €c/kWh at a size of 976 modules, followed by configuration B with a minimum electricity unit cost of 30.593 €c/kWh at a size of 964 modules. The minimum electricity unit cost achieved by prototype configuration A is by far the highest: 31.030 €/kWh at a size of 645 modules. Finally, the analysis shows that configurations D and B not only provide the lowest minimum CSP plant electricity unit costs but, need the lowest capital costs to manufacture at their optimum system size.

Acknowledgments

This work was supported in part by the Seventh Framework Program of Research and Development of the European Union, Contract No: FP7-ENERGY-2010-1/256797.

References

[1] A. Poullikkas, G. Kourtis, I. Hadjipaschalis, An overview of csp cooling systems, in: Proceedings of the 3rd International Conference on Renewable Energy Sources & Energy Effciency, Nicosia, Cyprus, 2011.

[2] B. Kelly, Nexant parabolic trough solar power plant systems analysis, Tech. Rep. NREL/SR-550-40163, National Renewable Energy Laboratory (2006).

[3] P. Liu, Z. H. Duan, Numerical investigation of hot air recirculation of air-cooled condensers at a large power plant, Applied Thermal Engineering 29 (2009) 1927–1934.

[4] W. Micheletti, J. Burns, Emerging issues and needs in power plant cooling systems, in: Proceedings of Water issues in Fossil Energy Workshop, 2002.

[5] Concentrating solar power commercial application study: Reducing water consumption of concentrating solar power electricity generation, Report to congress, U.S Department of Energy (2009).

[6] M. A. Valencia, Solar power scale-up in the mena: Resolving the associated water use challenges, The Environment and the Middle East 1 (2011) 13–19.

[7] The development and verification of a novel modular air cooled condenser for enhanced concentrated solar power generation-maccsol ec contract no. 256797.
URL `www.drycooledcsp.eu`

[8] F. Trieb, Trans-csp trans-mediterranean interconnection for concentrating solar power, Tech. rep., Technical report for the German Ministry of Environment, Nature Conservation and Nuclear Safety (2006).

[9] P. Viebahn, Y. Lechon, F. Trieb, The potential of concentrated solar power (csp) in africa and europe – a dynamic assessment of technology development, cost development and life cycle inventories until 2050, Energy Policy 39 (8) (2011) 4420–4430.

[10] The mediterranean solar plan.
URL `www.enpi-info.eu`

[11] A. Poullikkas, I. Hadjipaschalis, G. Kourtis, The cost of integration of parabolic trough csp plants in isolated mediterranean power systems, Renewable and sustainable energy reviews 14 (2010) 1469–1476.

[12] A. Poullikkas, R. Grimes, E. Walsh, I. Hadjipaschalis, G. Kourtis, Optimization analysis of innovative modular air-cooled condensers for csp plants, in: Proceedings of the 8th Mediterranean Conference on Power generation, transmission, distribution and energy conversion (MED-POWER), Cagliari, Italy, 2012.

[13] A. Poullikkas, Economic analysis of power generation from parabolic trough solar thermal plants for the mediterranean region – a case study for the island of cyprus, Renewable and Sustainable Energy Reviews 13 (2009) 2474–2484.

[14] A. Poullikkas, A decouple optimization method for power technology selection in competitive markets, Energy Sources 4 (2009) 199–211.

[15] A. Poullikkas, I. Hadjipaschalis, G. Kourtis, Comparative assessment of an innovative dry-cooled csp system, in: Proceedings of the Power Options for the Eastern Mediterranean Region (POEM) conference, Limassol, Cyprus, 2012.