Efficiency and costs of different concentrated solar power plant configurations for sites in Gauteng and the Northern Cape, South Africa

Thomas Telsnig
Institute of Energy Economics and the Rational Use of Energy (IER), University of Stuttgart

Ludger Eltrop
Institute of Energy Economics and the Rational Use of Energy (IER), University of Stuttgart

Hartmut Winkler
Department of Physics, University of Johannesburg

Ulrich Fahl
Institute of Energy Economics and the Rational Use of Energy (IER), University of Stuttgart

Abstract
Concentrated solar power (CSP) plants can play a major role in the future South African electricity mix. Today the Independent Power Producer (IPP) Procurement Programme aims to facilitate renewable energy projects to access the South African energy market. In spite of this incentive programme, the future role of CSP plants in South Africa has yet to be defined. Using hourly irradiance data, we present a new method to calculate the expected yield of different parabolic trough plant configurations at a site in each of Gauteng and the Northern Cape, South Africa. We also provide cost estimates of the main plant components and an economic assessment that can be used to demonstrate the feasibility of solar thermal power projects at different sites. We show that the technical configurations, as well as the resulting cost of electricity, are heavily dependent on the location of the plant and how the electricity so generated satisfies demand. Today, levelised electricity costs for a CSP plant without storage were found to be between 101 and 1.52 ZAR_{2010}/kWh_{el}, assuming a flexible electricity demand structure. A CSP configuration with Limited Storage produces electricity at costs between 1.39 and 1.90 ZAR_{2010}/kWh_{el}, whereas that with Extended Storage costs between 1.86 and 2.27 ZAR_{2010}/kWh_{el}. We found that until 2040 a decrease in investment costs results in generating costs between 0.73 ZAR_{2010}/kWh_{el} for a CSP plant without storage in Upington and 1.16 ZAR_{2010}/kWh_{el} for a configuration with Extended Storage in Pretoria. These costs cannot compete, however, with the actual costs of the traditional South African electricity mix. Nevertheless, a more sustainable energy system will require dispatchable power which can be offered by CSP including storage. Our results show that the choice of plant configuration and the electricity demand structure have a significant effect on costs. These results can help policymakers and utilities to benchmark plant performance as a basis for planning.

Keywords: solar thermal power plants, performance model, cost analysis, location

1. Introduction

Technologies to generate electricity from the sun can be broadly divided into photovoltaic systems and concentrated solar thermal systems. Whereas, photovoltaic systems are able to convert diffuse, indirect sunlight into electricity, concentrated solar thermal power (CSP) plants rely on the direct normal irradiance (DNI) of the sun to concentrate its rays onto a receiver, heating up a thermal fluid. The production of thermal energy can be seen as the main advantage of CSP, allowing it either to generate electricity in a conventional power block directly or to feed a thermal storage assembly, thereby enlarging the availability of the power plant.

Owing to the high insolation in South Africa and a growing demand for base-load power, concentrating solar thermal power plants can play a prominent role in the country's future energy mix. Commercial-scale solar thermal power plants have been built in other parts of the world, for example, in Spain and the USA. Despite the excellent climate conditions, the deployment of this technology is lagging behind in South Africa. One of the reasons is the low cost of electricity generated mainly from coal.

Several schemes of Renewable Energy Feed-In Tariffs (REFIT) have been implemented in South Africa with the aim of supporting the deployment of renewable energy projects. In 2009, the National Energy Regulator of South Africa (NERSA) calculated REFIT on the basis of the levelised cost of electricity to support renewable energy technologies in the country. In March 2011, the tariff scheme was reviewed, resulting in the following tariffs for CSP plants: 1.836 ZAR_{2011}/kWh for a parabolic trough with 6 hours storage, 1.938 ZAR_{2011}/kWh for a parabolic trough without storage, and 1.399 ZAR_{2011}/kWh for a solar tower with 6 hours storage (NERSA, 2011). Currently, Eskom (the national energy utility) plans to build a 100 MW solar tower near Upington in the Northern Cape Province, which will be commissioned in 2016 (AFDB, 2012).

In June 2011, the Department of Energy (DoE) initiated the Renewable Energy IPP Procurement Programme to encourage independent power producers to access the South African energy market. In the first round, 28 preferred renewable energy projects were selected in a bidding process, which represent a capacity of 1416 MW (DoE, 2011a). Moreover, the prices of the electricity generated have been capped for each renewable energy-generating technology. In the case of CSP, a relatively high value of 2.850 ZAR_{2010}/kWh was set (Creamer, 2011). Two CSP projects were chosen to be built, the Khi Solar One 50 MW solar tower with storage at Upington, Northern Cape, and the KaXu Solar One 100 MW parabolic trough plant at Paulputs, also in the Northern Cape. Construction of both systems, by Abener Energía, S.A., will start in the second half of 2012 (ABENER, 2012).

The increased competition for the projected power plant capacity forces the manufacturer to calculate the project costs accurately. The installation of a CSP plant therefore requires a detailed knowledge on the direct normal irradiance at a proposed site and an accurate estimation of the expected yield. Moreover, the electricity generated is heavily influenced by the configuration chosen for the CSP plant. The application of thermal storage systems offers, in particular, the possibility of delivering dispatchable power to the grid.

In this paper, we present a methodology to calculate the electricity yield of different parabolic trough plant configurations. Our findings indicate that, today, all case studies investigated generate electricity at costs below the defined price cap of the IPP Procurement Programme. More importantly, we analysed the costs of the different power plant components and we conducted a cost optimisation exercise for different power plant configurations. This paper provides information on the optimal storage capacity for different solar field sizes to satisfy a flexible or a constant demand structure. Moreover, variations in solar irradiation are taken into account by calculating an upper and lower limit of generating costs using data on the maximum and minimum insolation at the two locations investigated.

All costs quoted in this work are given in South African rands (1 ZAR corresponds to 9.70 □ in our calculations) in real terms for a base year of 2010, as ZAR_{2010}.

2. Theoretical background

2.1 Capacity development

The principle of converting the direct normal irradiance (DNI) of the sun into electricity on a commercial power plant scale has been applied since the 1980s, when the first unit of the Solar Electric Generating Station (SEGS) went into operation in California (Duffie and Beckman, 2006). The SEGS assembly uses parabolic trough technology with a supplementary natural-gas-fired boiler, which operates during peak hours in summer and at times of reduced insolation (NEXTera Energy, 2012). Between 1991 and 2005, no additional CSP capacity on a commercial scale was installed. In 2006, however, with the construction of the Saguaro power plant (1.16 MW) and Nevada Solar One (75 MW) in the USA, and the completion of Andasol 1 and Andasol 2 (each 50 MW) in 2008 in Spain, the deployment of CSP plants took off again.

Figure 1 shows the growth in global capacity since 1985. The two periods 2005–2010 and 2010–2012 saw a sharp increase in new plant capacity. From 2005 to 2010, 470 MW was deployed whereas in the last two years the capacity increased by a further 726 MW. Today, approximately 95% of the collective worldwide CSP capacity uses parabolic trough technology; 4% is based on solar towers. The Linear Fresnel reflector is a relatively new power plant technology concept on the way to commercial availability, which has been introduced in hybrid power plants in combination with a conventional power plant. Dish Stirling systems have become of minor relevance; the Maricopa Solar Project, with a capacity of 1.5 MW, is the only large scale Dish Stirling power plant currently in operation (NREL, 2011).

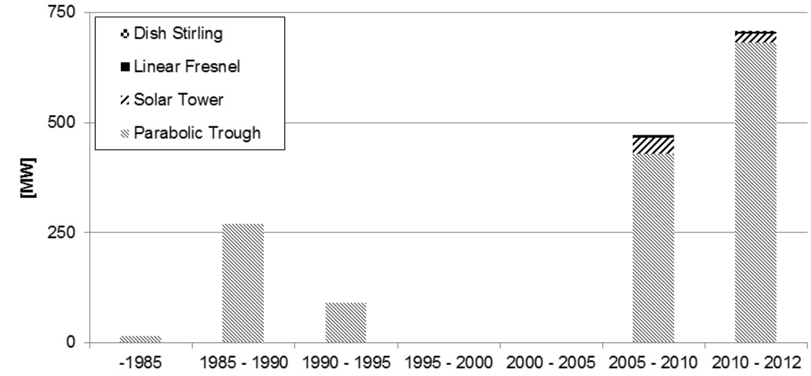

Figure 1: The growth in global CSP capacity between 1985 and 2012

2.2 The role of storage

Depending on the targeted supply duty of a CSP plant, its configuration can vary markedly. Today, CSP plants in the US generally supply the increased peak demand during hot summer days and therefore storage options are not considered. Most power plants built in Spain, by contrast, show high capacity factors provided by sensible-heat, two-tank molten salt storage systems. In that case, excess energy from the collector is converted into thermal storage during solar peak hours and discharged afterwards during periods of reduced insolation and at night. Beside this commercial-scale storage technology, different other storage systems are currently under development to reduce investment costs. These prototype storage systems include sensible-heat storage in solid media (concrete storage), latent heat storage using phase change materials (PCM), and thermochemical storage systems (Laing *et al.,* 2012; Bayón *et al.,* 2010; Felderhoff and Bogdanovic, 2009).

In October 2011, the Gemasolar power plant in Spain started operation, and was the first base-load CSP plant capable of delivering 15 equivalent hours per day of turbine capacity from thermal storage (Torresol Energy, 2011). Although solar tower projects are expected to play a prominent role in the future South African CSP market, this paper focuses on the economic and technical assessment of a parabolic trough power plant with and without storage at the two locations considered in this study.

2.3 Cost of power plant components

The investment costs of a solar thermal power plant are dependent on its configuration. A high capacity factor, and thus a high availability, can be achieved only by the use of an adequate storage system and a collector field big enough to provide sufficient thermal heat to feed the storage. To find the minimal generation costs for a given collector field size (see section 4), the first step is to determine the specific investment costs for each plant component and the operating and maintenance costs. The study reported here follows the approach of Trieb *et al.* (2009) by separating the power plant into three main components: the solar field, the storage system and the power block (Trieb *et al.,* 2009). The following assessment is based on cost data from different case studies of actual power plants and published projections of future cost data.

Sargent & Lundy (2003) (S&L) looked at the different components of the solar field and used the SEGS plants as a reference case. The cost projection includes improvements in the technology used for the collector structure, heat collecting elements and mirrors as well as up-scaling effects based on an increased production volume by using a learning curve approach. The storage costs projections have been excluded for this investigation because at the time of the S&L publication there were only prototype storage options available (Sargent & Lundy LLC Consulting Group, 2003; Neij, 2008).

The cost projections of Trieb *et al.* (2009) are based on a learning curve approach and assume a progress ratio of 90% for the solar field, 92% for the storage option and 98% for the power block with a cumulative CSP capacity of 500 GW by 2050 (Trieb *et al.,* 2009). These assumptions have been updated in a cost projection of CSP plants for the MENA (Middle East and North Africa) region, which investigated the costs of the import of solar thermal electricity to the European grid (BMU, 2010).

The projections of Turchi *et al*. (2010) are made up of 5 different cases until 2020, including technology improvements and up-scaling in the average capacity. For future solar field costs, Turchi *et al.* (2010) identified a progressive cost reduction for the structure itself and especially by changing the heat transfer fluid from the current synthetic oil to a molten salt heat transfer fluid. The storage option develops from the current two-tank molten salt storage to a thermocline direct storage. For the calculation of future costs for parabolic trough plants for the US market the Solar Advisor Model (SAM) has been applied (Turchi *et al.,* 2010). By using this cost performance model, Hinkley *et al.* (2011) give an estimate of the different cost components for a parabolic trough plant in Queensland, Australia

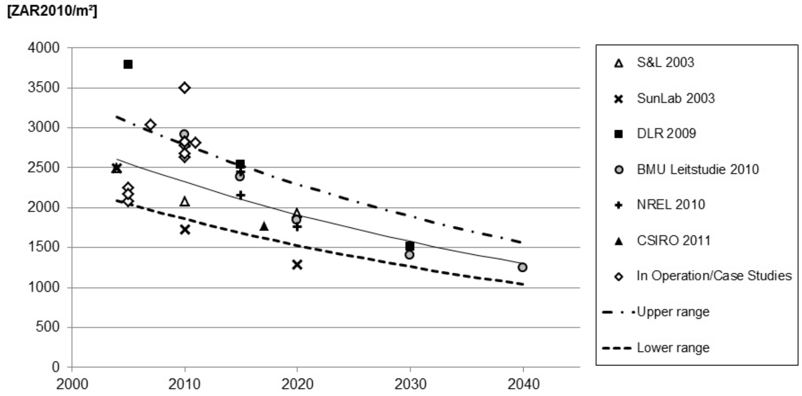

Figure 2: Cost development of the solar collector field until 2040

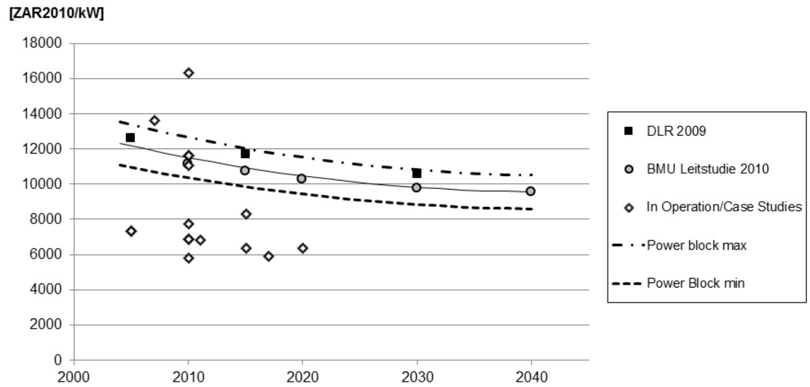

Figure 3: Cost development of the power block up to 2040

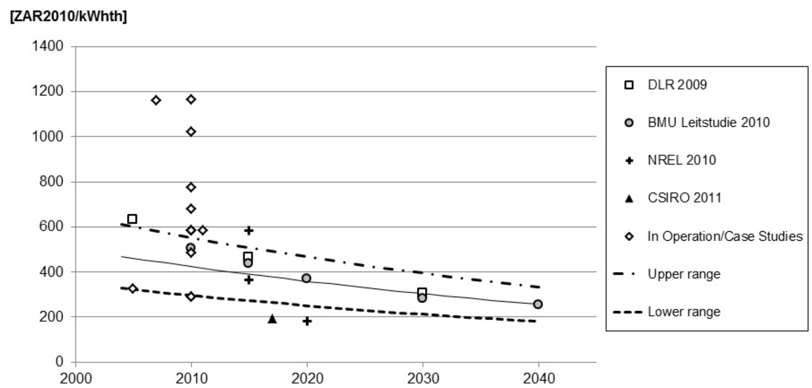

Figure 4: Cost development of the storage option up to 2040

(Hinkley *et al.,* 2011). Figures 2–4 show the projections for the three main cost components.

The costs of the first component (the solar field) include collecting elements, mirrors, heat transfer fluid, receiver tubes and field piping. Moreover, specific investment costs for the storage option covers tanks, heat exchangers and pumps, whereas the cost of the power block consists of the steam turbine, steam generator and the balance of the plant. It can be seen that specific solar field costs in 2010 were between 2000 ZAR_{2010}/m^2 and 2800 ZAR_{2010}/m^2. The specific investment costs for the storage option is heavily dependent on the storage technology. Considering current two-tank molten salt storage costs of 500 ZAR_{2010}/kWh_{th} to 600 ZAR_{2010}/kWh_{th} can be found. In the case of specific power block costs the cost data presented differ significantly because of different power plant concepts; such data were found to range between 7000 ZAR_{2010}/kW and 12000 ZAR_{2010}/kW.

2.4 Cost development

A regression analysis of the different cost projections was conducted to derive possible future trends of the specific investment costs of each component. In a second step, actual cost data of current case studies and actual power plants (see Figure 2 – 4: diamonds) were added and compared with the cost projections.

It can be seen that the projections of future investment costs decrease for all plant components, most significantly for the solar field and the storage system. Minor cost reductions are expected for the power block system because conventional technology is already in use in this regard. The varying uncertainty in investment costs over time is indicated in terms of a band around the regression line defining an upper and lower limit in investment costs of the different cost projections. The assumed uncertainty range in specific investment costs which covers most of the collected data points is 20% for the solar field, 30 % for the storage option and 10% for the power block.

Figures 2–4 show all investment cost projections, cost data obtained from actual case studies and operational power plants as well as the defined band with upper and lower limits around the regression line. It can be seen that the investment cost of the power block reported in the literature varies widely, because different power plant concepts were considered. Therefore, only the DLR study (Trieb *et al.,* 2009) and the Leitfaden study (BMU, 2010), which investigated the costs of CSP plants including storage devices, have been considered in our calculation of the cost trajectory of the power block. To define an upper bound when calculating the levelised electricity costs, the upper range of the specific investment costs of each component (dot-dashed line in Figures 2–4) was taken.

Table 1 shows the specific costs for each power plant component and its reference unit for the years 2010 and 2040.

The labour cost can be divided into two groups: staff assigned to the maintenance of the solar field, and personnel for maintenance, operation and administration of the rest of the plant (Maier, 2009). Without solar field maintenance, the power plant requires manpower of 28 people. Labour costs vary between 445,700 ZAR_{2010}/a for the plant manager and 124 300 ZAR_{2010}/a for an unskilled employee (OSEC, 2009). Maintenance of the solar field requires 0.03 employees per 1000 m^2 of aperture area.

Fossil fuel (diesel) is used in a supplementary heater when the demand cannot be satisfied by the collector or the storage option. For all configurations, a diesel-fired heat transfer fluid (HTF) boiler is considered with a diesel price of 1.75 ZAR_{2010}/GJ in 2010 and 2.35 ZAR_{2010}/GJ in 2040 (Tomaschek *et al.,* 2012). The daily co-firing ratio is capped at 12% of solar electricity production, which is equal to the co-firing ratio in the Spanish CSP plants. Moreover, the connection to the grid is taken into account by calculating the grid connection costs at 17.3 $MZAR_{2010}$/km of transmission line (Arlt *et al*., 2011; Eskom, 2010). The lifetime of the CSP plant is assumed to be 20 years. To calculate the levelised electricity costs, we assume an interest rate of 8% and insurance costs of 0.5%/a of the investment costs.

Based on this data, the later described performance model defines the optimal configuration for a given collector field area.

3. Methodology

In this section, we introduce the basic assumptions and the methodology to calculate the optimal configuration of a parabolic trough power plant under different demand conditions. To show the interactions between solar irradiance, demand structure, power plant components and resulting costs, we investigated two different sites, namely, Pretoria and Upington. Upington in the Northern Cape, can experience the highest irradiance levels in the country and was chosen as a preferred destination for CSP projects (AFDB, 2012; Torresol Energy, 2011). Pretoria, as one of the main economic hubs of South Africa, receives less irradiation but is close to one of the main centres of electricity consumption; to a dense transmission grid network; and demon-

Table 1: Specific investment costs (upper limit) of parabolic trough power plant components and O&M costs for 2010 and 2040

Component	*Unit cost*	*Reference unit*	*2010*	*2040*
Investment costs				
Solar field	ZAR_{2010}/m^2	aperture area (m^2)	2 785	1 560
Power block	ZAR_{2010}/kW	capacity (kW)	12 664	10 515
Storage	ZAR_{2010}/kWhth	storage capacity (kWhth)	552	335
O&M costs				
Plant manager	ZAR_{2010}/a		445 700	
Unskilled worker	ZAR_{2010}/a		124 300	
Solar field maintenance	employees/1000m^2	aperture area (m^2)	0.03	
Co-firing costs (Diesel)	ZAR_{2010}/GJ		1.75	2.35
Insurance costs	%/Inv.a	annual investment (Inv.a)	0.5%	

strates increased demand for electricity during peak hours in winter, which corresponds to high insolation at that time of the year, all of which make CSP an interesting option in this part of the country. To factor in the connection to the existing transmission grid, we assumed distances of 10 km from the Pretoria plant site and 20 km from the corresponding site in Upington to the grid substation.

3.1 Site-specific assumptions and solar measurements

Only the direct component of the solar irradiance can be used in CSP technologies. This component can be calculated by measuring both the global and diffuse radiation. Data sets of the two sites, Pretoria and Upington, were used with measurements of hourly global and diffuse radiation using thermopile pyranometers. The evaluation of the solar irradiation measurements is fully described in an accompanying paper (Winkler *et al.,* in press).

The solar irradiance measurements were originally collected by the South African Weather Bureau (now referred to as South African Weather Service), and have been analysed and reported on by Eberhard (1990), Power and Willmott (2001) and Tsubo and Walker (2003). The data set for Pretoria covers the years 1957 to 1997, and for Upington the period from 1964 to 1992 (Eberhard, 1990; Tsubo and Walker, 2003; Power and Willmott, 2001). An hourly time resolution of the irradiation data is necessary when considering the behaviour of the different power plant components. Moreover, the latitude of the installation site influences the incident angle of radiation and thus affects the geometric loss factors. The losses which are caused before (geometric losses) and after (thermal losses) the irradiance reaches the receiver, were calculated using the method described in Trieb *et al.* (2004) in order to obtain the resulting heat that can be used at the power plant (Trieb *et al*., 2004).

3.2 Performance model parbolic trough

The electricity generated by a solar thermal power plant is influenced by several factors. First, it has to be specified what role in the electricity supply system is envisaged for the power plant. This could be the supply of peak demand during daytime or the transfer of base-load power into the grid. The availability of different CSP configurations (with and without storage) can be determined by several methods using a differing depth of solar irradiation data. Trieb *et al*. (2009) outlined an equation to calculate the full load hours as a function of the average yearly irradiance and the Solar Multiple of the plant, which was derived from hourly time series of different power plants exposed to different irradiance levels. The Solar Multiple is the ratio of heat collected by the solar field and the nameplate thermal power of the turbine (Trieb *et al.,* 2009). The use of energy storage, or co-firing, during periods of reduced insolation requires a higher resolution of irradiance data, otherwise an accurate prediction of the energy generated would be impossible. Moreover, the size of each plant component, such as the storage capacity, can be obtained only by using long time series of hourly data of the DNI at a specific location.

Several system performance models have been developed to calculate the expected energy yield from hourly irradiance data. Generally, these performance models can be divided into two groups: first, system those based on existing empirical values and, second, performance models which use a bottom-up approach by calculating the energy balances on the basis of the physical and geometric properties of the system investigated (Wagner and Gilman, 2011). The following performance models, as well as the model presented in this study, do so using the second approach.

Stine and Geyer (2001) describe a solar energy system model (SIMPLESYS) with a control logic that determines the appropriate mode of operation for every time step. To satisfy the demand, the model distinguishes between seven different modes of operation and is composed of a collector field, a thermal storage option and an auxiliary heater (Stine and Geyer, 2001). Wagner and Gilman (2011) developed the so-called Physical Trough model, which is used in the NREL Solar Advisor Model. They provide a more complex control logic, which chooses between four operating modes. These modes indicate if the operation of the turbine can be ensured and determine the defocusing parameter of the solar field. Moreover, the model considers part load behaviour when energy is below the design power point (Wagner and Gilman, 2011).

The control logic presented in this study is based on Stine´s model and expands on his basic control logic, with additional decision nodes that regulate the contribution of co-firing for the plant. Other additional features of the control logic presented are given by the introduction termination conditions in the case that a storage option is not available, and in the consideration of additional transition modes. The transition modes ensure that within a time step more than one mode meets the demand required. This can be the case at night, for instance, if the storage unit runs out of thermal energy and additional energy is supplied by the heat transfer fluid heater.

Figure 5 illustrates the control logic used in this study and the main parameters that define the appropriate mode of operation.

Heat flows can be expressed using the following equation:

$$Q_{COLL} + Q_{AUX} = Q_{LOAD} + Q_{DUMPED} \pm {}_{QSTOR} \quad (1)$$

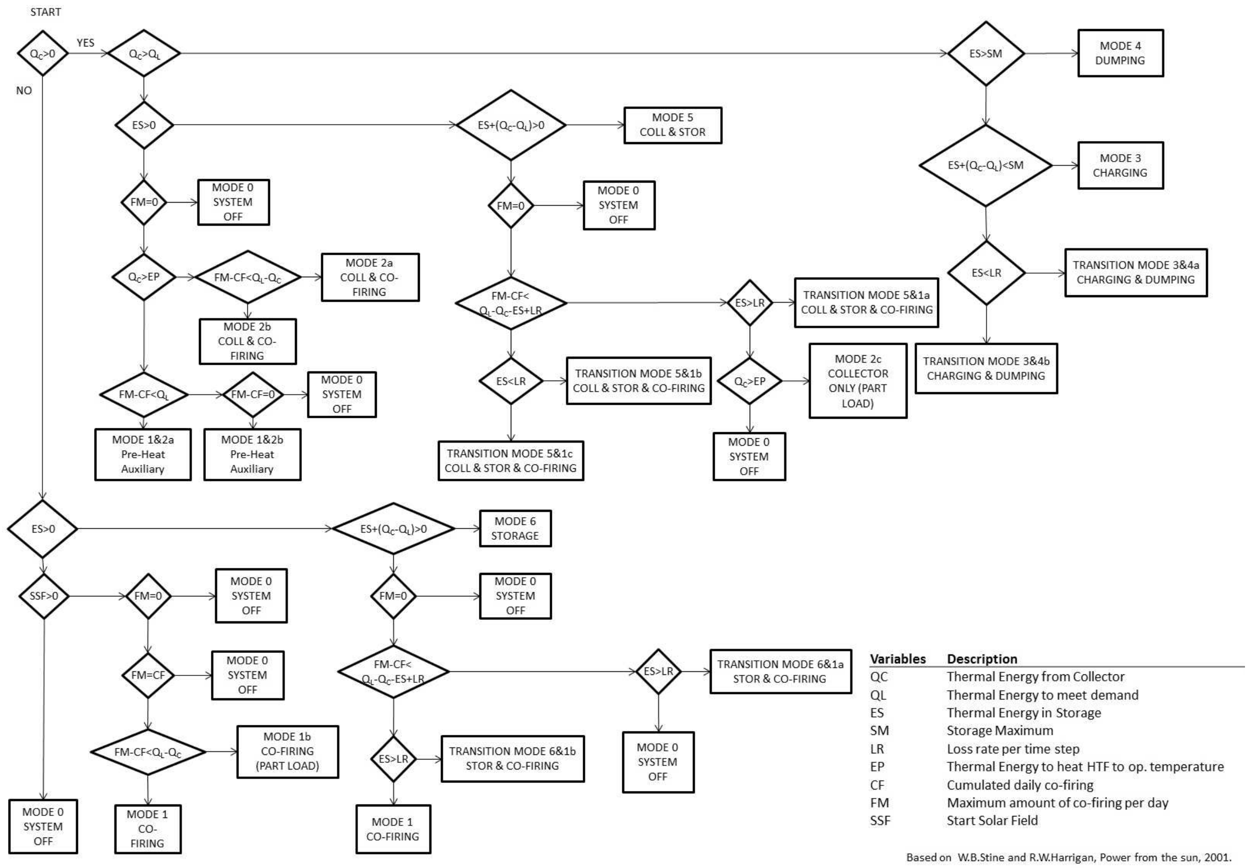

Figure 5: Control logic of CSP performance model

where Q_{COLL} is the thermal energy of the collector field, Q_{AUX} is the heat from the auxiliary boiler, Q_{LOAD} is the heat load at the steam generator that should be satisfied by the system, Q_{DUMPED} is the thermal energy that has to be dumped because it exceeds the actual load, and the storage capacity $_{QSTOR}$ is the heat which is fed into or from storage. For the power plant system as a whole, the heat flow equation (Equation 1) is solved every hour. The main heat fluxes depend on diverse input parameters that determine the capacity of the different components:

- Maximum storage size
- Actual thermal energy in storage
- Storage loss rate (per time step)
- Thermal energy to heat HTF to operational temperature
- Cumulated daily co-firing (per time step)
- Maximum amount of co-firing per day

These input parameters limit the time of operation of the respective components each day. The energy collected from the solar field Q_{COLL} is influenced mainly by the size of the collector and by the incident radiation at the collector field. To derive a realistic band for the electricity generated by the model power plants, the maximum and minimum years of irradiance are taken from the two data sets. The co-firing of the auxiliary boiler is ensured by using diesel; the amount of co-firing is capped at 12% of the electricity generated daily.

Defining the demand is necessary to derive the appropriate configuration of the power plant, and therefore heat load Q_{LOAD} the system should fulfil. In this investigation two different demand structures are considered. First, it is assumed that all electricity generated can be fed into the grid even if it exceeds or falls below the demand (flexible demand); and second, it is assumed that the demand to be satisfied is constant (constant demand). Finally, three different types of power plant configurations are defined: The first configuration (Solar Only) has a collector field aperture area of 600 000 m^2, which is comparable in size to actual CSP projects and operates without a storage option. In this case, it is assumed that the power plant should satisfy the flexible demand structure. For the Solar only option, a simplifying assumption is made. It is assumed that the steam turbine is able to follow the wide fluctuations in insolation during the day. The second configuration (Limited Storage) has the same collector field size but includes a storage option, which enables the system to generate electricity at times of low insolation and at night. The third configuration (Extended Storage) consists of an increased aperture area of 1 800,000 m^2 capable of feeding a large storage unit. Both configurations including a storage option are used to satisfy constant electricity demand. Table 2

Table 2: The power plant configurations investigated

Configuration	*Aperture area (m^2)*	*Storage*	*Demand structure (capacity)*	*Location*	*Irradiation data*	
					Best year	*Worst year*
Solar only	600 000	No	Flexible (50MW)	Pretoria	1997	1990
				Upington	1981	1974
Limited storage	600 000	Yes	Constant (50MW)	Pretoria	1997	1990
				Upington	1981	1974
Extended storage	1 800 000	Yes	Constant (50MW)	Pretoria	1997	1990
				Upington	1981	1974

summarizes the configurations investigated and the corresponding assumptions.

To find the appropriate storage size for the last two configurations, a cost optimisation was conducted based on the cost data determined. This was done by running the performance model for a given collector field size and varying storage sizes. For each model run the levelised electricity costs were calculated so that the storage size corresponding to minimum cost was derived.

4. Results: Generating costs and optimal storage sizes of CSP

Figure 6 shows the costs of electricity for the different plant configurations investigated for Upington, calculated with low irradiation data. It can be seen that by calculating the levelised electricity costs of the two configurations which include a storage option, a cost minimum was found. The dotted line indicates the price cap of 2.85 ZAR_{2010}/kWh_{el}, which was set for CSP projects in the Renewable Energy IPP Procurement Programme (DoE, 2011b). It is assumed that a periodic adjustment of the actual tariff scheme to take account of inflation will result in a constant compensation rate in real terms during the lifetime of the model power plants (Standard Bank, 2011).

The minimal costs were calculated for each of the power plant configurations investigated at the two locations. Moreover, the maximum and minimum years of solar irradiation data at the site were used. A range of storage sizes and plant levelised electricity costs were thereby obtained.

Figure 7 shows the range of levelised electricity costs for the different power plant configurations at the two locations. It can be deduced that although the site at Upington has generally lower costs of electricity, the best and worst year of irradiance of the data set influences the spread of costs drastically. Substantial differences were found in the availability of electricity generated by the power plants, owing to their varying storage capacities. When comparing these results, it has to be noted that the different availability as well as the assumed demand structure have a strong effect on energy system security. Whereas, the Extended Storage configuration has the ability to provide base-load power, the fluctuating electricity generation of the Solar Only option affects the energy system because it cannot provide reliable capacity at night and at times of low insolation.

The Solar Only option leads to the lowest levelised electricity costs, corresponding to 1.24–1.52 ZAR_{2010}/kWh_{el} at Pretoria and 1.01–1.35 $ZAR_{2010}/$

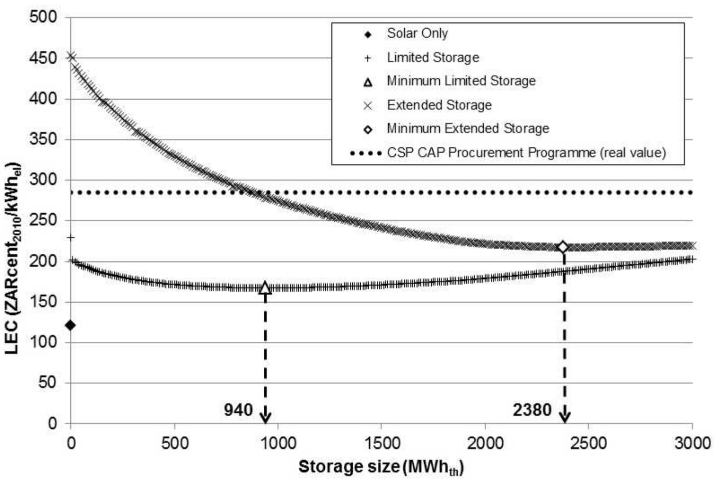

Figure 6: Levelised electricity costs and optimal storage size of different plant configurations at Upington in a low-irradiation year

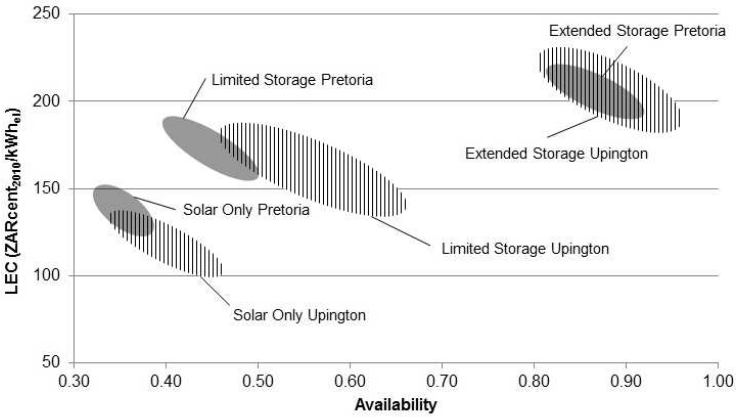

Figure 7: Range of levelised electricity costs and the corresponding availability of power for the different plant configurations in 2010

kWh_{el} at Upington. The Limited Storage configuration shows increased costs of 1.59–1.90 ZAR_{2010}/kWh_{el} at Pretoria and 1.39–1.84 ZAR_{2010}/kWh_{el} at Upington. The main reasons for these cost differences are the storage option implemented and the respective demand structures to be satisfied. In the case of the Extended Storage option, the highest costs correspond to 1.93–2.19 ZAR_{2010}/kWh_{el} at Pretoria and 1.86–2.27 ZAR_{2010}/kWh_{el} at Upington. The optimal storage capacities calculated for the last two configurations are given in Table 3. It can be seen that the storage capacity for the Extended Storage configuration has the same magnitude in both cases and that it declines at the higher irradiance level. This decrease in storage capacity occurs because of two factors. First, a relatively high and more uniformly distributed insolation regime reduces the need for storage operation. Second, in contrast to the Limited Storage option, storage capacity cannot be enlarged any further because it already covers the nocturnal hours and an increase in storage capacity would increase the levelised costs of electricity.

The performance model presented here allows us to analyse at what time the different components are in operation. The system performance of the cost-optimised configuration at a particular site can be observed. The model gives information about the system behaviour during different seasons and the capacity factor can be calculated by summarizing the different modes of operation occurring in the course of a year.

The different operation modes for each configu-

Table 3: Storage capacity of different plant configurations

Site	*Irradiance*	*Limited storage (MWh_{th})*	*Extended storage (MWh_{th})*
Pretoria	low	560	2 370
	high	780	2 360
Upington	low	940	2 380
	high	1 250	2 360

Table 4: Duration of operational modes and capacity factors in 2010

Configurations	*Location*	*Irradiance*	*Operation modes (h/a)*				*Capacity factor*
			Collector	*Storage*	*Auxiliary*	*Off*	
Solar only	Pretoria	low	2 422	0	427	5 911	0.33
		high	2 846	0	538	5 376	0.39
	Upington	low	2 480	0	508	5 772	0.34
		high	3 325	0	730	4 706	0.46
Limited storage	Pretoria	low	2 455	687	321	5 297	0.40
		high	2 886	1 097	406	4 372	0.50
	Upington	low	2 500	1 167	357	4 736	0.46
		high	3 356	1 923	525	2 956	0.66
Extended storage	Pretoria	low	2 805	4 114	218	1 623	0.81
		high	3 250	4 596	196	719	0.92
	Upington	low	2 751	4 047	239	1 722	0.80
		high	3 602	4 754	89	315	0.96

ration have been analysed on an hourly basis to find the time each component is in operation. At times when two or more modes are working simultaneously, the respective share is assigned to each operational mode. The Extended Storage option is characterised by a larger storage operation than the Limited Storage alternative, which results in a reduced demand for co-firing. Moreover, the co-firing periods for the Solar Only configuration are greater owing to the flexible demand that was assumed for this configuration. The capacity factor of each configuration is calculated in a second step (see Table 4).

When apportioning the levelised electricity costs into major cost components, significant differences between the configurations can be found. For example, component costs of the Solar Only configuration are generally relatively low, which can be explained by the flexible demand structure initially assumed. For this case, the solar field costs account for 47–52% of the plant's total generation costs whereas the Limited Storage and Extended Storage options account for 41–48% and 63–64% of these costs, respectively. The share of power block costs decreases from 18–20% for Solar Only and 16–18% for Limited Storage to 8% for the Extended Storage option.

As previously shown storage capacity plays a significant role in total generation costs. The Limited Storage option accounts for 12–17% whereas Extended Storage for both plant locations corresponds to 17% of total electricity generation costs. The fixed operation and maintenance costs (FOM) remain constant for all configurations at 7%. The costs for co-firing depend greatly on the storage size of the plant. The cost share of the Solar Only option ranges between 16–19% and 11–12% for the Limited Storage configuration. The Extended Storage option shows a low share of co-firing costs with 1–2% of the generation costs as a consequence of the high capacity factor of this configuration. The different sites require connection to the grid to be considered separately. For this reason the calculation of grid connection costs was added to the electricity generation costs of the power plant. The proportion of grid connection costs decreases from 5–10% for the Solar Only and 5–9% for the Limited Storage configurations to 2–4% for the Extended Storage alternative (see Figure 8).

5. Future costs of CSP at the two investigated sites

We examined the future performance of CSP plants by enlarging the collector field size of each configuration, which led to an upscaling of the overall capacity of each plant (see Table 5). An average plant capacity of 200 MW is assumed in 2040, in view of optimistic projections of future CSP plant concepts (Viebahn *et al.*, 2008). For this purpose, a fourfold increase in the collector field area was assumed and again costs were optimised by running the performance model using cost data for the year 2040 (see section 2.4).

The increased capacity of the power plants modelled requires an adequate enlargement of the storage facility. The calculated optimal storage capacities are between 4000 MWh_{th} and 4790 MWh_{th} for the Limited Storage configuration at Pretoria and Upington, respectively. The Extended Storage configuration presents different results. The additional collector field area, which allows the power plant operation to be extended, results in an optimal storage capacity of 9600 MWh_{th} at Pretoria, whereas the corresponding capacity at Upington was calculated to be 9010 MWh_{th}. The reason for this difference in storage capacity between the two configurations is the amount of energy that has to be dumped at high

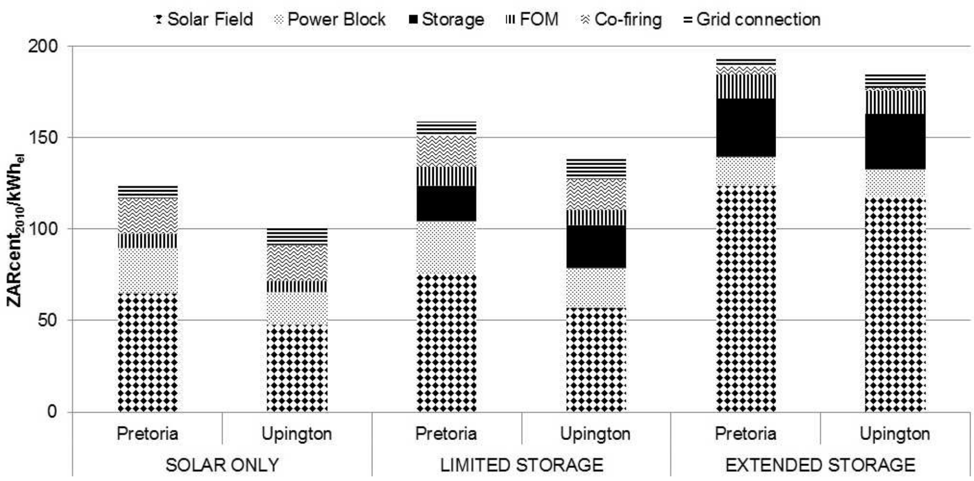

Figure 8: Schematic representation of major cost components of different plant configurations in 2010 (a high-irradiance year)

Table 5: The power plant configurations corresponding to 2040

Configuration	*Aperture area (m^2)*	*Storage*	*Demand structure (capacity)*	*Location*	*Irradiation data Best year*	*Worst year*
Solar only	2 400 000	No	Flexible (200MW)	Pretoria	1997	1990
				Upington	1981	1974
Limited storage	2 400 000	Yes	Constant (200MW)	Pretoria	1997	1990
				Upington	1981	1974
Extended storage	7 200 000	Yes	Constant (200MW)	Pretoria	1997	1990
				Upington	1981	1974

capacity factors. The Extended Storage configuration at Upington has to dump the energy collected more often during the year because of the more constant irradiance. In contrast, the marked differences in insolation between summer and winter in Pretoria require a much higher storage capacity to deliver base-load power.

All investigated power plant configurations modelled in this study demonstrate significant cost reduction potential. The Solar Only option shows a decrease in costs of 25% and 26% for Pretoria and Upington, respectively, compared with levelised electricity costs in 2010. Figures for both configurations including a storage option indicate a further cost reduction potential of 29%–31% and 40%–41% for the Limited Storage and the Extended Storage options, respectively (see Figure 9).

6. Discussion and conclusion

Rising energy demand and mainly coal-based electricity generation make South Africa one of the greatest emitters of greenhouse gases in the world. With its agreement to adopt CO_2 mitigation policies within the United Nations Framework Convention on Climate Change (UNFCCC), the country has taken an important step in combating climate change (Winkler, 2007). In the electricity-generating sector, renewable energy technologies are an alternative to the existing coal-fired power plants. One of the main challenges that renewable technologies have to cope with is that the electricity they generate fluctuates widely. The installation of CSP plants with storage, which are able to provide a constant supply of electricity, could overcome irregular supply.

Depending on the amount of renewable energy in the South African grid, the future role of CSP will either consist of supplying only additional electricity during the day, or be used as base-load power plants to compensate for the fluctuations in output of other renewable energy technologies by using an appropriate storage option. The location of the installation and electricity demand structure affect the capacity of the optimal storage required, which is one of the main cost drivers of a plant. Moreover, the Extended Storage configuration demonstrates a reduced demand for fossil fuel co-firing because of its high capacity factor. Our results are comparable with the costs of existing installations and cost projections. Hinkley *et al.* (2011) calculated the costs of a 100 MW CSP plant with 6 hours of storage

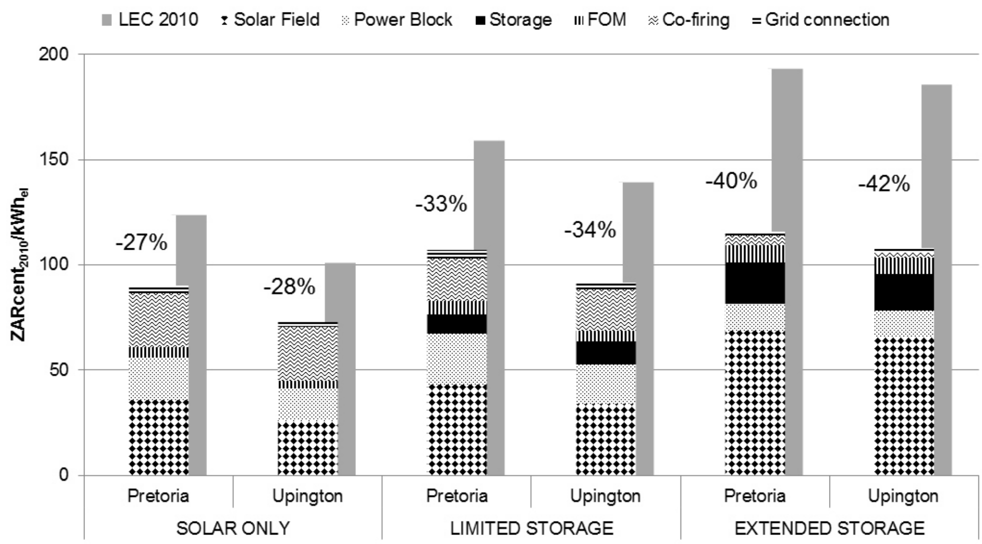

Figure 9: Levelised electricity costs in 2040 of the three case studies investigated, and cost reduction potential compared with costs in 2010 (a high irradiance year)

capacity to be 1.50 ZAR_{2010}/kWh_{el} (Hinkley *et al*., 2011). Turchi *et al.* (2010) investigated different current and future power plant configurations for cost reduction and derived levelised electricity costs of between 0.72 and 1.31 ZAR_{2010}/kWh_{el} (Turchi *et al.,* 2010).

Compared with other renewable electricity generating technologies for Gauteng and elsewhere in southern Africa, CSP competes especially well with photovoltaics and wind power. Telsnig *et al*. (2012) investigated different renewable electricity-generating technologies at locations in Gauteng and the Northern Cape and found costs for photovoltaics of between 1.45 and 1.63 ZAR_{2010}/kWh_{el} and for wind power plants of between 0.49 and 1.09 ZAR_{2010}/kWh_{el} (Telsnig *et al.,* 2012). The costs of photovoltaics are comparable with those for CSP, whereas wind energy is considerably cheaper. However, only concentrated solar power offers the possibility of storing the electricity generated and to deliver a constant electricity supply. The importance of CSP base-load power will therefore increase, to the benefit of a more uniform and stable national electricity supply, if the electricity sector adopts a more sustainable technology mix.

Acknowledgements

This research is part of the Megacity Research Project, EnerKey, which is a German-South African collaboration to develop an integrated energy and climate change concept for Gauteng Province in South Africa. It is funded by the German Federal Ministry of Education and Research through Grant Number 01LG0503A1 to the University of Stuttgart/IBP/IZT/TÜV Rheinland, the South African National Research Foundation through Grant Number FA2006022800010 to Harold Annegarn (University of Johannesburg), the South African National Energy Development Institute (SANEDI) through Grant Number OTH-0607-043, and the University of Johannesburg Quick Wins EnerKey programme. The solar irradiation data was compiled by the South African Weather Bureau (now the South African Weather Service). The authors appreciate the efforts of Graham Baker and Harold Annegarn for critical review.

References

Abener, (2012). Abener Solar plants. www.abener.es/colab/web/en/negocio/solar/solares/, accessed 19 January 2012.

AFDB, (2012). Eskom Renewable Energy Invest. Project. African Development Bank Group-Website. www.afdb.org/en/projects-and-operations/project-portfolio/project/p-za-f00-002/, accessed 3 February 2012.

Arlt, D., Novitzkij, A., Westermann, D., and Wolling, J., (2011). Metastudie über Merkmale von Freileitungen und Erdkabelleitungen. Ilmenau: Technische Universität Ilmenau, Institut für Energie-, Antriebs- und Umwelttechnik.

Bayón, R., Rojasa, E., Valenzuelab, L., Zarzab, E., and Leónb, J., (2010). Analysis of the experimental behaviour of a 100 kWth latent heat storage system for direct steam generation in solar thermal power plants. *Applied Thermal Engineering,* 30 (17-18): 2643-2651.

Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU), 2010. Leitstudie 2010 – Langfristszenarien und Strategien für den Ausbau der erneuerbaren Energien in Deutschland bei Berücksichtigung der Entwicklung in Europa und global. BMU.

Creamer, T., (2011). SA unveils the names of first 28 preferred renewables bidders. Engineering News Online. www.engineeringnews.co.za/article/sa-unveils-the-names-of-first-28-preferred-renewables-bidders-2011-12-07, accessed 15 December 2011.

Department of Energy South Africa (DoE), (2011a). Department of Energy – List of IPP Preferred Bidder. www.energy.gov.za/files/events_frame.html, accessed 30 January 2012.

Department of Energy South Africa (DoE), (2011b). Request for qualification and proposals for new generation – Part A: General requirements, rules and provisions. www.ipprenewables.co.za/page/post/view/id/169#page/post/view/id/213, accessed 15 August 2012.

Duffie, J. and Beckman, W., (2006). Solar Engineering of Thermal Processes. 3rd edition. New Jersey: Jon Wiley and Sons.

Eberhard, A., (1990). A Solar Radiation Handbook for Southern Africa. Cape Town: Elan Press.

Eskom, (2010). Transmission Development Plan 2010-2019 – Revision I. Johannesburg: Eskom Transmission Division.

Felderhoff, M. and Bogdanovic, B., (2009). High Temperature Metal Hydrides as Heat Storage Materials for Solar and Related Applications. *International Journal of Molecular Sciences,* 10 (1): 325-344.

Hinkley, J., Curtin, B., Hayward, J., Wonhas, A., Boyd, R., Grima, C., Tadros, A., Hall, R., Naicker, K., and Mikhail, A., 2011. Concentrating solar power – drivers and opportunities for cost competitive electricity. www.garnautreview.org.au/update-2011/commissioned-work/concentrating-solar-power-drivers-opportunities-cost-competitive-electricity.pdf, accessed 20 January 2012.

Laing, D., Bahl, C., Bauer, T., Fiss, M., Breidenbach, N. and Hempel, M., (2012). High-Temperature Solid Media Thermal Energy Storage for Solar Thermal Power Plants. *Proceedings of the IEEE,* 100 (2): 516- 524.

Maier, G., (2009). Concentrated Solar Power (CSP) – facts and opportunities. Präsentation IEA – Netzwerktreffen 24. November 2009.

National Renewable Energy Laboratory (NREL), 2011. Solarpaces – Concentrating Solar Power Projects. NREL SOLARPACES. www.nrel.gov/csp/solarpaces/project_detail.cfm/projectID=58, accessed 16 January 2012.

Neij, L., (2008). Cost development of future technolo-

gies for power generation — a study based on experience curves and complementary bottom-up assessments. *Energy Policy*, 36 (6): 2200–2211.
National Energy Regulator of South Africa (NERSA), (2011). NERSA Consultation Paper Review of Renewable Energy Feed – In Tariffs. www.nersa.org.za/, accessed 15 January 2012.
NEXTera Energy, (2012). Factsheet Solar electric Generating Systems. Nextera energy resources, www.nexteraenergyresources.com/pdf_redesign/segs.pdf, accessed 15 January 2012.
OSEC Business Network Switzerland, (2009). Personalkosten Südafrika. www.osec.ch/internet/osec/de/home/ipssa/destination/rm/location_factors/costs/human.html, accessed 1 March 2011.
Power, H.C. and Willmott, C.J., (2001). Seasonal and interannual variability in atmospheric turbidity over South Africa. *International Journal of Climatology*, 21 (5): 579–591.
Sargent & Lundy LLC Consulting Group, (2003). Assessment of Parabolic Trough and Power Tower Solar Technology Forecasts. www.*nrel.gov/docs/fy04osti/34440.pdf,* accessed 14 February 2012.
Standard Bank, (2011). The IPPPP RFP – Debate: Renewable Energy in South Africa. http://greencape.co.za/upload/IRPStandardBankPresentationAugust2011.pdf, accessed 15 August 2012.
Stine, W. and Geyer, M., (2001). Power from the Sun. Power from the Sun. www.powerfromthesun.net, accessed 1 June 2011.
Telsnig, T., Özdemir, E.D., Tomaschek, J., and Eltrop, L., (2012). EnerKey Technology Handbook – A guide of technologies to mitigate greenhouse gases towards 2040 in South Africa. Stuttgart: Institute for Energy Economics and the Rational Use of Energy (IER), University of Stuttgart.
Tomaschek, J., Özdemir, E.D., Fahl, U., and Eltrop, L., (2012). Greenhouse gas emissions and abatement costs of biofuel production in South Africa. *GCB Bioenergy*, doi: 10.1111/j.1757-1707.2011.01154.x: 1-12.
Torresol Energy, (2011). Gemasolar – Connected to the sun. www.torresolenergy.com/EPORTAL_DOCS/GENERAL/SENERV2/DOC-cw4e88b3bb57c8f/folleto-gemasolar.pdf, accessed 16 February 2012.
Trieb, F., Kronshage, S., Quaschning, V., Dersch, J. Lerchenmüller, H., Morin, G., and Häberle, A., (2004). SOKRATES-Projekt – Solarthermsiche Kraftwerkstechnologie für den Schutz des Erdklimas.
Trieb, F., O´Sullivan, M., Pregger, T., Schillings, C., and Krewitt, W., (2009). Characterisation of Solar Electricity Import Corridors from MENA to Europe – Potential, Infrastructure and Costs. Stuttgart: German Aerospace Center (DLR), Institute of Technical Thermodynamics.
Tsubo, M. and Walker, S., (2003). Relationships between diffuse and global solar radiation in southern Africa. *South African Journal of Science,* 99 (7/8): 360.
Turchi, C., Mehos, M., Ho, C.K., and Kolb, G.J., (2010). Current and Future Costs for Parbolic Trough and Power Tower Systems in the US Market. www.nrel.gov/docs/fy11osti/49303.pdf, accessed 25 January 2012.
Viebahn, P., Kronshage, S., Trieb, F., and Lechon, Y., (2008). Final report on technical data, costs, and life cycle inventories of solar thermal power plants. www.needs-project.org/index.php?option=com_content&task=view&id=42&Itemid=66, accessed 6 June 2012.
Wagner, M.J. and Gilman, P., (2011). Technical Manual for the SAM Physical Trough Model. Golden: NREL.
Winkler, H., (2007). Long Term Mitigation Scenarios: Technical Summary. Department of Environment Affairs and Tourism. www.environment.gov.za/hotissues/2009/LTMS2/LTMSTechnicalSummary.pdf, accessed 9 May 2012.
Winkler, H., Telsnig, T., and Eltrop, L., (in press). Comparing long-term solar data sets from South Africa´s Gauteng industrial heartland and the Upington designated solar energy generation hub – implications for solar energy generation strategies. Submitted to *Renewable Energy*.