The Moroccan Solar Plan -

A comparative analysis of CSP and PV utilization until 2020

by

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The present master thesis conducts technical and economic simulations of large-scale Photovoltaic (PV) and Concentrated Solar Power (CSP) plants for the Moroccan Solar Plan. It provides a database of performance indicators such as energy yields, capacity factors, typical efficiencies and losses of technical components, LCOE, and difference costs (DC: LCOE minus avoided costs of the conventional power system) for fixed tilted, 1-axis horizontal, 1-axis vertical and 2-axis tracking PV and CSP with no, 6, 12 and 18 full load hours of thermal storage. HelioClim irradiation data of 2005 for the sites in Ouarzazate, Ain Ben Mathar, Boujdour, Laayoune and Tarfaya is used ranging between 1,927 - 2,428 kWh/m²/y (DNI) and 1,968 - 2,154 kWh/m²/y (GHI).

In the base scenario minimum LCOE are 9.6 - 5.4 EURct/kWh for PV (2012 – 2020) varying between 0.90 - 1.55 EURct/kWh among sites and technologies. CSP reaches 12.8 - 9.2 EURct/kWh and a bandwidth of 2.3 - 1.6 EURct/kWh. Average DC are lowest for horizontal 1-axis tracking (0.4 and -7.7 EURct/kWh for plants built in 2012 and 2020 respectively) and CSP with 6 hours of storage (1.3 and -3.5 EURct/kWh). PV is cheaper for all sites and technologies due to higher learning curves and less initial investment, but cannot contribute to coverage of the daily evening peak in Morocco.

Four different MSP-scenarios with 2000 MW of solar energy require total investments of 3.7 - 7.5 billion EUR and yield 7.9% - 12.8% of the electricity demand in 2020 (given a growth 7%/y) depending on the ratio of PV and CSP utilization. The average LCOE are 8.3 - 11.7 EURct/kWh and the total discounted DC (10%/y) are -254 - 391 million EUR. Thus, solar energy is partly less expensive than a business-as-usual scenario.

An extensive sensitivity analysis for WACC and price escalation of conventional energy shows that for only PV and only CSP scenarios in 55 and 22 out of 72 cases the DC are negative - although no environmental costs for conventional generation are internalized. The weighted average extra costs of a feed-in tariff for the analyzed scenarios range between 0.4% - 8.1% of today’s electricity price until break-even with conventional energy.
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ABBREVIATIONS

ac = alternating current
Capex = capital expenditures
CSP = Concentrated Solar Power
dc = direct current
DC = difference costs
DLR = Deutsches Zentrum für Luft- und Raumfahrt = German Aerospace Center
DNI = direct normal irradiation
GIZ = Deutsche Gesellschaft für International Zusammenarbeit = German Society for International Cooperation
GHI = global horizontal irradiation
HDKR = Hay-Davies-Klucher-Reindl (model)
HTF = heat transfer fluid
HV = high voltage
IAM = Incidence Angle Modifier
IWES = Fraunhofer Institute for Wind Energy and Energy System Technology (IWES) in Kassel
LV = low voltage
LCOE = Levelized Cost of Electricity
MAD = Moroccan Dirham
MASEN = Moroccan Agency for Solar Energy
MENA = Mediterranean and North Africa
MSP = Moroccan Solar Plan
MV = medium voltage
NREL = National Renewable Energy Laboratory
ONE = Office National de l’Electricité = National Electricity Company
Opex = operational expenditures
PB = power block
PPA = power purchase agreement
PV = photovoltaic
RCREEE = Regional Center for Renewable Energy and Energy Efficiency
RE = renewable energy
SAM = System Advisory Model
SANDIA = SANDIA National Laboratories
SF = solar field
SM = solar multiple
STC = standard testing conditions
TES = thermal energy storage
TSO = transmission system operator
WACC = weighted-average of capital costs
NOMENCLATURE

\[ A_i = \text{anisotropy index} \]
\[ A = \text{area} \]
\[ a = \text{empirical coefficient SANDIA module model} \]
\[ b = \text{empirical coefficient SANDIA module model} \]
\[ C = \text{concentration ratio} \]
\[ c = \text{empirical coefficient} \]
\[ ^\circ C = \text{degree Celsius} \]
\[ \text{CO}_2 = \text{carbon dioxide} \]
\[ \cos \theta = \text{cosine loss coefficient} \]
\[ c_{pw} = \text{heat capacity of water} \]
\[ crf = \text{annuity factor} \]
\[ C_v = \text{ventilator constant} \]
\[ D_C = \text{width of collector} \]
\[ d = \text{diameter} \]
\[ dT = \text{temperature difference between module back cell} \]
\[ E = \text{share of equity} \]
\[ E_{net} = \text{net electricity generation} \]
\[ ET = \text{equation of time} \]
\[ E_{th,fth} = \text{thermal energy required for full load hour} \]
\[ E_{th,max} = \text{maximum storage capacity} \]
\[ E_{th,pb} = \text{thermal energy available for power block} \]
\[ E_{th,stored} = \text{thermal energy in storage} \]
\[ D = \text{share of debt} \]
\[ f = \text{focal length of collector} \]
\[ f_m = \text{modulating factor of HDKR-model} \]
\[ f_w = \text{wind speed loss coefficient} \]
\[ f_1(AM_d) = \text{solar spectral influence on} I_{sc} \text{due to air mass variation} \]
\[ f_2(\theta) = \text{optical influence on} I_{sc} \text{due to solar angle of incidence} \]
\[ f_d = \text{fraction of diffused irradiation} \]
\[ F_{TC} = \text{Temperature correction factor} \]
\[ G = \text{irradiance (W/m}^2\text{)} \]
\[ GR_t = \text{growth rate of specific year} \]
\[ g = \text{gravitation constant} \]
\[ H = \text{daily irradiation (J/m}^2\text{)} \]
\[ H_{ST} = \text{hour of the day (sun time)} \]
\[ h = \text{enthalpy} \]
\[ I = \text{hourly irradiation (J/m}^2\text{)} \]
\[ IAM_c = \text{incidence angle modifier loss coefficient} \]
\[ I_e = \text{effective irradiance} \]
\[ I_{dc,max} = \text{maximum dc input current of inverter} \]
\[ I_{mp} = \text{maximum power point current} \]
\[ I_{ref} = \text{irradiation at STC} \]
\[ I_{sc} = \text{short circuit current} \]
\[ I_{sco} = \text{short circuit current under STC} \]
\[ k_e = \text{return on investment of equity} \]
\[ k_d = \text{return on investment of debt} \]
\[ k_{ins} = \text{annual insurance costs} \]
\[ km = \text{kilometer} \]
\[ kWh = \text{kilowatt hour} \]
\[ kWh/m_2/y = \text{kilowatt hour per meter square per year} \]
\[ L = \text{length} \]
\[ L_C = \text{length of collector row} \]
\[ L_{loc} = \text{longitude (local)} \]
\[ L_p = \text{parasitic load} \]
\[ L_{st} = \text{standard meridian for the local time zone} \]
\[ M_{string} = \text{number of modules in string} \]
\[ MW = \text{Megawatt [W = J/s]} \]
\[ m = \text{mass flow} \]
\[ N = \text{plant lifetime} \]
\( N_s \) = number of cells in series per string
\( n \) = diode factor of module
\( O_3 \) = ozone
\( P_{\text{gross}} \) = gross power output
\( P_{\text{net}} \) = net power output
\( P_n \) = night power consumption of inverter
\( P_{\text{so}} \) = minimum dc power inverter power
\( P_{x,0} \) = production historically cumulated output level \( x \), initial output level \( 0 \), in year \( t \)
\( p \) = pressure
\( q \) = heat flow
\( q_c \) = convection heat losses
\( q_e \) = elementary charge
\( q_{\text{in}} \) = total heat used in power block
\( q_r \) = radiation heat losses
\( q_{\text{SF to PB}} \) = heat from solar field to power block
\( q_{\text{TES,loss}} \) = storage heat loss
\( q_{\text{TES to PB}} \) = heat from storage to power block
\( R \) = Distance of collector rows
\( R_B \) = geometric factor of HDKR model
\( R_C \) = row end loss coefficient
\( S_C \) = Shading loss coefficient
\( SFO_{DP} \) = solar field output in design
\( S_{\text{parallel}} \) = Strings in parallel
\( T \) = temperature
\( U \) = heat loss coefficient [W/m²K]
\( V_{dc,\text{max}} \) = maximum dc input voltage of inverter
\( V_{\text{aco}} \) = nominal dc input voltage of inverter
\( V_{\text{mpo}} \) = maximum power point voltage of module
\( W \) = Watt
\( W/m^2 \) = Watt per meter square
\( w \) = velocity of cooling water
\( \vartheta \) = maximum power temp. coefficient of module
\( \Omega \) = latitude
\( \omega \) = hour angle
\( \Delta z \) = difference in altitude
\( PBO_{DP} \) = power block output in design point
\( P_{\text{aco}} \) = nominal dc power output of inverter

**Greek letters**

\( \alpha \) = solar elevation angle
\( \alpha_{\text{lsc}} \) = normalized temperature coefficient for \( I_{sc} \)
\( \alpha_{\text{imp}} \) = normalized temperature coefficient
\( \beta \) = tilt angle
\( \beta_{\text{mp}} \) = temperature coefficient of maximum power voltage
\( \gamma \) = surface azimuth angle
\( \gamma_s \) = solar azimuth angle
\( \delta \) = Sun declination angle
\( \delta(T_c) \) = thermal voltage
\( \varepsilon_r \) = reflection coefficient of mirror
\( \varepsilon \) = emissivity of absorption pipe
\( \theta \) = angle of incidence
\( \theta_z \) = zenith angle
\( \eta_{\text{cycle}} \) = cycle efficiency
\( \eta_C \) = generator efficiency
\( \eta_{PB} \) = power block efficiency
\( \eta_{SF} \) = solar field efficiency
\( \eta_{SF,\text{geo}} \) = geometrical efficiency of solar field
\( \eta_{SF,\text{opt}} \) = optical efficiency of solar field
\( \eta_{SF,\text{th}} \) = thermal efficiency of solar field
\( \eta_{SP} \) = efficiency of cooling pump
\( \eta_V \) = efficiency of ventilator
\( \mu \) = transmission coefficient of mirrors
\( \vartheta \) = dirt coefficient of mirrors
\( \nu_W \) = wind speed
\( \pi \) = pi
\( \rho \) = density
\( p_g \) = ground albedo
\( \rho_m \) = quality coefficient of mirrors
\( \sigma \) = Stefan-Boltzmann-constant
\[ \sigma_T = \text{transmission coefficient of cover} \]
\[ \tau = \text{absorption coefficient of absorber pipe} \]

**Symbols**

\[ \Xi = \text{loss coefficient for pump} \]
\[ \Upsilon = \text{pipe roughness} \]
\[ \Psi = \text{field loss coefficient} \]

**Subscripts**

\[ a = \text{ambient} \]
\[ b = \text{beam} \]
\[ d = \text{diffuse} \]
\[ g = \text{global} \]
\[ n = \text{normal} \]
\[ o = \text{extraterrestrial} \]
\[ r = \text{reflected} \]
\[ t = \text{tilted (surface)} \]
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The present master thesis has been conducted between 15\textsuperscript{th} of August, 2011 and 15\textsuperscript{th} of February 2012. The author visited and worked in different institutions in Egypt, Morocco and Germany gaining helpful insight for the own research, assistance and guiding to conduct the present work.

From 15\textsuperscript{th} of August to end of September the author conducted a field trip in Morocco. He worked for some weeks at the office of the “Deutsche Gesellschaft für internationale Zusammenarbeit” (GIZ) in Rabat, conducting his research on the Moroccan Energy System and meetings with different interview partners in Morocco.

Interview partners have been found in several important institutions in the Moroccan energy landscape such as: The “Office National de l´Electricité” (ONE), the “Agence Nationale pour le Développement des Energies Renouvelables et l’Efficacité Energétique” (ADEREE), the Moroccan Agency for Solar Energy (MASEN), the NAREVA Holding and the GIZ.\textsuperscript{1}

After the field research in Morocco the technical part of this thesis was prepared during an internship in September 2011 at the Fraunhofer Institute for Wind Energy and Energy System Technology (IWES) in Kassel, Germany. The author was able to finalize his thesis and discuss results at the same institution in January and February 2012. During November and December the author worked in cooperation with the Regional Center for Renewable Energy and Energy Efficiency in Cairo (RCREEE), Egypt.

The author would like to thank all institutions and engaged people for helpful insight and discussion.

\textsuperscript{1} Please find a list of conducted interviews, partners and institutions in appendix A.
1 Introduction

1.1 Motivation and Aims

The resources and potentials for renewable energies (RE) in the Middle Eastern and North African (MENA) countries are vast. Numerous studies have analyzed the possible contribution from RE in all MENA-countries. Indicatory studies such as the MED-CSP, AQUA-CSP and TRANS-CSP claim that RE are capable of coping with the region’s growing energy demand presenting “... the least cost option for energy [and] ... the key for socio-economic development and sustainable wealth in MENA... “.² They hint at the possibility to combine power generation and sea water desalination exporting substantial amounts of electricity from MENA to the European Union (DLR, 2005; DLR, 2007; DLR, 2006). Further studies indicate the RE-potential in MENA and Morocco and underline the low additional costs compared to upcoming climate problems and resource scarcity (Czisch, 2006; DF, 2011).

However, challenges faced by the integration of RE in MENA energy systems are well known: High initial investments, Levelized Cost of Electricity (LCOE) well above national end-consumer prices, political uncertainty and lacking regulatory frameworks. For Morocco lacking access to sufficient financing, a low-level of infrastructure and high taxes compared to European standards may represent further barriers according to (Werenfels/Westphal, 2010). The energy demand in Morocco is expected to increase continuously between 5 - 7 % p.a. until 2020 - just as it did in the last decade. Being highly dependent on energy imports, Morocco will face huge energy costs if prices continue to increase and therefore, needs to diversify its energy sources (MEMEE, 2009a; Cherkaoui, 2010).

Because of these challenges RE attract increasing interest from countries in MENA. The majority developed RE targets for the future. Morocco has launched the most ambitious strategy in the MENA-region demanding that 42% of the installed capacity for electricity generation is from RE (RCREEE, 2010). Within this strategy the Moroccan Solar Plan (MSP) takes a vital role. Until 2020 the installment of 2000 MW of solar power generation capacity is foreseen - from either Photovoltaic (PV) or Concentrated Solar Power (CSP). Five locations with high annual solar irradiation were selected to host between 100 - 500 MW of solar power capacity - Ouarzazate, Boujdour, Ain Ben Mathar, Tarfaya and Laayoune.

This work analyzes and compares the energy contribution, costs and performance of the employment of single CSP and PV plants in all of these locations. It thereafter develops four scenarios

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to assess the potential national contribution of the MSP to the Moroccan energy supply in 2020 comparing associated costs.

This work aims at achieving three objectives:

1. To technically and economically model different PV and CSP systems with sufficient accuracy to display hourly, daily and seasonal production patterns realistically.
2. To derive a knowledgeable data base for technical and economic performance indicators for the utilization of PV and CSP in all sites of the MSP.
3. To model different MSP-scenarios assessing their costs and impacts, highlighting advantages and disadvantages of CSP and PV and ideally determining the optimum ratio of employment of both technologies.

1.2 Methodology

The analysis is based on modeling in Microsoft EXCEL delivering a joint approach including technical, economic and energy system aspects in one model. The developed tool models hourly power output of variably sizable CSP and PV systems in all five locations of the MSP comparing the following technologies: On the one hand parabolic trough CSP with no, 6, 12 and 18 hours of thermal energy storage (abbreviated SM 1, SM 2, SM 3 and SM 4 respectively, SM = solar multiple), on the other hand fixed tilted, horizontal and vertical continuous 1-axis tracking as well as continuous 2-axis tracking (abbreviated 1, 2, 3, 4 respectively). Based on these results, annual performance characteristics of all plants in all sites are deduced such as capacity factors, energy yield and hourly dispatch.

The economic analysis is represented by two different approaches: The first approach is to calculate the LCOE. The second represents the difference costs (DC) approach which compares between costs of conventional electricity generation (based on indications given by ONE and escalating over time) and the LCOE of solar power (constant over time) from a plant lifetime perspective. The model finally allows varying the use of technology for the 2000 MW of solar power.

The analysis is conducted in several steps:

- Chapter 2 outlines fundamental characteristics of the Moroccan electricity market and the MSP
- Chapter 3 comes up with an comparative analysis of the direct normal irradiation (DNI) and global horizontal irradiation (GHI) from different data sources for all sites of the MSP
- Chapter 4 describes the model used for the technical power plant simulations which are derived from the collector model of the German Aerospace Center (DLR) for CSP parabolic trough and the SANDIA National Laboratories (SANDIA) PV module and inverter model
Chapter 5 introduces the economic models calculating the LCOE and DC which are based on the results of the technical analysis.

Chapter 6 discusses exemplarily the model results for a 50 MW reference plant in Ouarzazate for SM 1 - 4 (CSP) and 1 - 4 (PV): firstly, the technical characteristics are described and then validated by the System Advisor Model (SAM) of the National Renewable Energy Laboratory (NREL); secondly, a sensitivity analysis is conducted.

Chapter 7 briefly summarizes the results of all sites and discusses the differences between the assessed technologies and sites; it also introduces into relevant system related advantages and disadvantages of CSP and PV.

Chapter 8 derives four scenarios of the MSP analyzing investment costs, LCOE, break even with conventional generation costs, power production, residual load characteristics in 2020 and saved CO₂ emissions; additionally it proposes a national-feed-in tariff to ensure sufficient financing for the MSP.

Chapter 9 summarizes the previous findings and concludes recommendations for decision makers and stakeholders.

All calculations for this model are realized in seven different Excel-sheets. There is one containing the input data used for all plant simulations and economical assessments. It comprises especially financial and economic variables such as interest rates or loan terms. As core of the work, one Excel-sheet is developed for the plant simulation of PV and CSP. The technical model details are outlined in section 4.1 for CSP and 4.2 for PV. The economic modeling is very similar for both plants and jointly

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**Figure 1: Overview of developed Excel-sheets**

Source: own elaboration
described in chapter 5. Due to the already big file size of the spreadsheet it is more convenient to have five separate spreadsheets - each covering the calculations for one location. Separate calculation is necessary to enable all calculations to run with different site specific solar and weather data. The results of all site-specific simulations are summarized in a seventh spreadsheet where all MSP-scenarios are derived. The general methodology of the modeling approach is sketched in Figure 1.
2 Electricity in Morocco

2.1 Supply and Demand

Installed capacity

For the analysis in this work it is crucial to know about the most important characteristics of the Moroccan electricity market. So first of all, let’s have a glance at the supply side. The Moroccan electricity generation capacity and production are relatively small. In 2010 the installed capacity was 6,328 MW in total. Figure 1 shows the past development of the installed capacities for each technology from 2002 - 2010. Additionally, three different development scenarios for the future have been plotted in the same figure (MEMEE, 2009a; MEMEE, 2009). In summary, the graph underlines the following facts and trends:

- Bulk installed capacity is represented by fossil fuel-fired (68.5%) and hydro power plants (28%) while gas turbines and combined cycle plants represent most of the recently added capacity
- In most of the past years (especially 2002 - 2004 and 2006 - 2008) installed capacity has not or only insignificantly developed
- Future expansion needs to accelerate: a recent governmental scenario (MEMEE, 2009a) expects growth rates of 8.7% p.a. resulting in 14580 MW capacities until 2020 while older estimates (MEMEE, 2009) assume only growth rates of 3.0% and 4.7% p.a.

![Installed capacity in Morocco 2002 - 2020](image)

In detail for 2010: 2,385 MW of steam turbines (37.7%), 915 MW of gas turbines (14.5%), 186 MW of diesel generators (2.9%), 850 MW of combined cycle (13.4%), 1,770 MW of hydro power (28.0%, of which 464 MW is pump storage) and 222 MW of wind power capacity was installed (3.5%).

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3 In detail for 2010: 2,385 MW of steam turbines (37.7%), 915 MW of gas turbines (14.5%), 186 MW of diesel generators (2.9%), 850 MW of combined cycle (13.4%), 1,770 MW of hydro power (28.0%, of which 464 MW is pump storage) and 222 MW of wind power capacity was installed (3.5%).
- Wind power employment is low with only 2.5% share of capacity and solar energy exists only in very small scale in rural electrification

**Electricity consumption**

In the last years the electricity consumption grew strongly imposing challenges on the Moroccan energy sector. In 2010 26,602 GWh of electricity has been generated - almost entirely by conventional electricity generation. The major share originates from fossil fuel-fired plants (69.2%) and hydro power (13.6%). Interestingly, a significant share of 14.7% has been imported and wind power provided only 2.5% of electricity (ONE, 2011).

Figure 3 shows the past generation structure, capacity factors for 2010 according to plant type and the past development of the electricity demand. It also displays the future electricity demand from 2011 until 2020 according to two scenarios. Both were adopted from projections published by the Moroccan government (MEMEE, 2009) which expects growth rates of 6.9% - 8.7% p.a. (scenario “base” and “disruptif” respectively). Accordingly, electricity demand will increase by a factor of 2.0 or 2.3 within the next 10 years - jumping from 26,602 GWh in 2010 to 52,000 - 61,000 GWh in 2020. In the last 8 years electricity demand has increased by a factor of 1.7 showing very high growth rates in the years 2003 - 2006 (8.0%, 6.6%, 11.5%, 9.4%) and more moderate rates between 2007 - 2010 (5.8%, 5.4%, 4.5%, 3.7%).

The following facts about the electricity production are also remarkable:

- Between 2002 and 2010 a bulky part of base load generation was provided by steam turbines running mainly on coal (78% - 89% of production) and partly on heavy fuel oil (22% - 11% of production)
- Hydro power generation is highly variable from year to year: in 2008, 2009, 2010 power production was 1,360 GWh, 2,952 GWh and 3,631 GWh respectively although installed capacity only increased by 2.4% from 2008 - 2010
- Since 2002 imports tend to increase drastically and peaked in 2009 providing a share of 18.9% of electricity generation; the transmission lines to Spain operate with a capacity factor of 64% thus, they are about to provide base to medium load
- Combined cycle plants in 2010 operated with 40% and gas turbines only with 7% capacity factor which indicates that production is costly if on the other hand electricity is imported

---

4 In detail: 14,451 GWh were produced by steam turbines (54.3%), 522 GWh by gas turbines (2.0%), 437 GWh by diesel generators (1.6%), roughly a 3000 GWh by combined cycle (11.3%), 3,631 GWh from hydro power (13.6%) and 659 GWh from wind power (2.5%).

5 All figures representing national electricity demand above and in Figure 3, are the sum of national net electricity production and imports.

6 See (COMELEC, 2003; Comelec, 2004; Comelec, 2005; Comelec, 2006; Comelec, 2007; Comelec, 2009).

7 These figures are somewhat surprising, but stated as mentioned in (ONE, 2011; ONE, 2009).
- Wind power generation is realized in excellent sites reaching an average capacity factor of 34% in 2010

![Figure 3: Key trends of electricity generation & import in Morocco 2002 - 2020](source)

**Load Curve**

The load curve plays a major role in structuring the energy supply in Morocco. As supply and demand of electricity must be equal at any moment of time, the load curve determines the requirements for the supply side. So let’s have a glance at characteristic load curves for the year 2010. Figure 4 shows the load curve in hourly resolution from day 1 to the last day of the year (grey area - upper x-axis). Additionally, characteristic days for each season and the average hourly values of the load for all 365 days are plotted in the same chart (lower x-axis).

![Figure 4: Characteristic load curves for Morocco in 2010](source)

---

9 All gas turbines operate on heavy fuel oil resulting in high fuel costs. It has not been investigated if technical problems may have caused such low capacity factors. However, no information has been found supporting this case.

9 The hourly load data for 2010 has been received by the author after a personal interview with Mohamed Mouchtakiri, head of the dispatch center of the TSO ONE in Morocco, Casablanca, on 9/9/2010 (Mouchtakiri, 2011).
The plots show the following main characteristics: All daily load profiles show low values during night hours (3:00 - 8:00), before the load drastically increases between 8:00 to 11:00. The mid-day peaking period lasts until 17:30 in winter and until 21:00 in summer. From this point the load usually increases again reaching the daily (absolute) evening peak depending on the season between 18:30 in winter and 21:30 in summer. The highest magnitudes for negative power gradients for the displayed days are ranging between -295 MW/h and -543 MW/h; the highest positive gradients between 507 MW/h and 675 MW/h. In general the load tends to increase in summer months.

All in all, electricity supply in Morocco is strongly dominated by conventional electricity generation and imports from Spain gain major importance to cover the demand successfully. The electricity consumption grew substantially in the last decade, while the expansion of installed capacity was at the edge to keep pace. Very ambitious expansion scenarios for the power generation capacity have to be considered so that peak demand and a desirable security margin can be guaranteed by domestic resources until 2020. The two daily peaking periods during mid-day and evening are apparent throughout the whole year and represent a significant characteristic of the Moroccan load curve. It becomes clear in later chapters that both peaks have great influence in the decision whether PV or CSP should be employed within the MSP.

2.2 Market Structure

In the following, the three sectors production, transmission and distribution are characterized. In Morocco the liberalization of the electricity sector is just about to start. The market is still dominated by monopolistic structures. The dominating actor in all sectors is the ONE founded in 1963. The ONE closely works together with the Ministry of Energy, Mines, Water and Environment (MEMEE). Since the 90’s and usually in order to bridge upcoming supply gaps, new actors entered into the production and distribution sector enabled by concessions and power purchase agreements (PPA) with ONE. The transmission sector remains a single buyer market until today. In the present work the sector descriptions remain very brief (see also Figure 5 for the most important facts). For a good overview and a more lengthy discussion of all sectors see (Jäger, 2009).

Production: Electricity is produced by either ONE, independent producers, auto producers or imports. In 2009 the four sectors accounted for 33.7%, 53.5%, 0.2% and 19.3% of the total electricity respectively.

ONE produces coal power, hydropower and electricity from fuel oil and diesel generators all over Morocco. Due to shortages of supply and the need for quick capacity addition independent (private) producers entered the market in 1997, 1998 and 2005, operating a 1360 MW thermal power plant, a
50 MW wind farm and a 380 MW combined cycle.\textsuperscript{10} The electricity produced by independent companies is sold under the rule of PPAs to ONE with long-term contracts covering 15 - 30 years.

Auto production is an option for the industry to generate its own electricity. For non-renewable auto producers access to the grid and purchase of excess energy by the transmission operator (TSO) are not guaranteed. In contrary, for renewable energy auto production grid access must be granted. For injected energy the TSO charges a transportation fee\textsuperscript{11}. Excess energy in this case can be sold to the TSO for the normal time-based high voltage (HV) grid price and a surplus of 20\% on top.\textsuperscript{12} This incentive package for renewable energy auto production is also called EnergiePro Scheme. The fourth source of electricity is import from Spain or Algeria (MEMEE, 2009a; RCREEE, 2010a).

**Transmission:** The transmission sector is a monopolistic market. The only company responsible and working as TSO is ONE. It operates as single buyer, purchasing all electricity from the producing sector and selling it to concessionary distribution companies or distributes the energy itself (MEMEE, 2009a).

**Distribution:** ONE is originally also responsible for the distribution of electricity. However, ONE can delegate this task to private companies (Opérateurs Privés) or to communal organizations (Regiés Communaux) by awarding them concessions in defined, usually urban regions. In total there are 11

\begin{itemize}
  \item They are operated by Jorf Lasfar Energy Company, JLEC, Compagnie Eolienne du Detroit, CED and a consortium of Endesa, Siemens and ONE respectively.
  \item This fee is fixed at 0.534 EURct/kWh for plants operating before 2011 and at 0.712 EURct/kWh after that, exchange rate: 11.2 MAD = 1 EUR, 11/1/2011.
  \item (RCREEE, 2010a) claims the resulting weighted average tariff results in 3.66 EURct/kWh, based on day, peak and off-peak tariffs for HV consumers of 3.0, 4.0 and 1.6 EURct/kWh respectively (exchange rate: 11.2 MAD = 1 EUR, 11/1/2011).
\end{itemize}
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distributing companies beside ONE. The latter is serving all remaining and rural areas of Morocco. Clients connected to the HV grid are only served by ONE. In total ONE distributes about 55% of the electricity. For a complete list of companies and market shares view (ONE, 2009).

2.3 Production Costs

Electricity prices in Morocco are high in comparison to other MENA countries. However, they are still well below LCOE for RE ranging between 5 - 13 EURct/kWh. The absence of a feed-in-tariff and low price guarantees for electricity from RE within the EnergiePRO scheme are further reasons for low employment of green energy.

In the context of this work end-consumer electricity prices are of minor importance. More relevant are production costs of existing conventional power plants, because all calculations for the DC in chapter 5 are based upon them. Data for the estimation of the production costs of the conventional generation system was provided by (Mouchtakiri, 2011)\(^{13}\) indicating 10 different cost levels in dependence of the national load. The load levels range from 1800 MW to 4800 MW and are divided in 300 MW steps. The corresponding indications are summarized in Table 1. Based on these assumptions, production costs can be calculated for each hour of 2010 by linear interpolation between two values.

<table>
<thead>
<tr>
<th>Load (MW)</th>
<th>2100</th>
<th>2400</th>
<th>2700</th>
<th>3000</th>
<th>3300</th>
<th>3600</th>
<th>3900</th>
<th>4200</th>
<th>4500</th>
<th>4800</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Cost (EURct/kWh)</td>
<td>4.0</td>
<td>4.4</td>
<td>5.6</td>
<td>6.0</td>
<td>6.0</td>
<td>6.8</td>
<td>8.0</td>
<td>8.0</td>
<td>9.6</td>
<td>9.6</td>
</tr>
</tbody>
</table>

Table 1: Production costs of electricity in Morocco in dependence of national load level
Source: own elaboration based on (Mouchtakiri, 2011)

The indications show that production costs are low, for low values of the load. That is because cheaper power plants (hydropower, coal) are sufficient to cover demand. Given a higher load more expensive gas and fuel oil fired power plants are used. Especially during peak periods in summer average costs reach up to 9.5 EURct/kWh due to the use of expensive power plants. The average electricity price is

Validation

For comparison of the given data the publication of (Trieb/Müller-Steinhagen/Kern, 2010) is useful. In this paper the authors calculate LCOE of peak, medium and base load power plants for a reference MENA country with a similar system size of Morocco (fired by coal, coal/fuel oil mix and fuel oil/diesel mix respectively). They calculate LCOE of 16.8 EURct/kWh for peak, 10.5 EURct/kWh for medium and 6.7 EURct/kWh for base load power plants. If these prices are adopted for an hour with

\(^{13}\) The data was provided by Mohamed Mouchtakiri during a personal interview with the author. Mouchtakiri is the head of the dispatch center in Morocco at ONE in Casablanca.
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4500 MW load in Morocco which is for instance covered by using 2147 MW of coal fired plants, 765 MW of combined cycle (regarded as medium load), 400 MW of hydro power, 400 MW of import and 800 MW of fuel oil fired power plants, the weighted average electricity price yields 8.8 EURct/kWh.¹⁴ This value is of similar magnitude as the corresponding indication of 9.6 EURct/kWh given by (Mouchtakiri, 2011) (see Table 1).

Furthermore the production costs determined by this method can be compared with end consumer prices in the market which are fixed by decree of the Moroccan Prime Minister. Figure 6 shows the production costs for the 1ˢᵗ of December 2010 according to the applied method increased by 30% for transmission and distribution and by 14% sales tax. For comparison end-consumer prices for high voltage, medium voltage (MV) and low voltage (LV) clients are depicted.

The tariffs for LV clients are constant throughout the day, but vary according to the category of consumer (household, agriculture, industry, rural consumer). Tariffs also vary according to the consumption rate; i.e. as in the case of private households. In Figure 6 only the lower and upper boundary of tariffs for LV clients - ranging from 7 - 13 EURct/kWh - are displayed¹⁵. The tariffs for MV and HV clients are divided in a night, day and peak time tariff approximately varying between 5 - 12 EURct/kWh according to the time of use. Figure 6 shows that a possible sales price calculated with the applied method and including 30% for transmission and distribution and 14% sales tax may be higher or lower than end-consumer prices depending on the load level and the specific tariff. If the method reflects real production costs, private end-consumers subsidize HV and MV clients which

¹⁴ The power plant capacities in the example represent 90% of installed capacity for coal and combined cycle in Morocco, 50% of transmission capacity (import), 30% of installed hydro power capacity in Morocco and 73% of installed fuel oil and diesel generation capacity. Production costs of hydro power and imports are assumed with 4 EURct/kWh and 5 EURct/kWh respectively; thus: \[2147 \times 6.7 + 765 \times 10.5 + 400 \times 4 + 400 \times 5 + 800 \times 16.8 / 4500 = 8.8.\]

¹⁵ For detailed listings of all available tariffs see (Jäger, 2009).
often have to pay less than the calculated sales price. Thus, the margin realized by ONE depends on the average tariff realized and the ratio of expensive to cheap tariffs.\textsuperscript{16}

All in all the presented approach seems to be a good guess for real production costs. Due to the lack of better data it provides the best source of information.

2.4 The Moroccan Solar Plan

Context of national strategy

In 2008 the Moroccan Government issued a first national strategy which comprehensively analyzed the development of the electricity sector and addressed the necessary effort to meet the growing demand in the short-term until 2015 (MEMEE, 2009a). Within this document all new power plants planned until the end of the year 2015 are listed. If realized they would increase the installed capacity to 12 GW in total at the end of 2015.

The new plants are listed in Table 2 sorted according to fuel type. At the end of 2011 all conventional projects scheduled until this date have been built. However, about 600 MW of planned wind farms are delayed or have not been installed at all. Further remaining big projects of conventional capacity are the extension of the Jorf Lasfar coal power plant and 2.6 GW additional coal power plants to be built between 2013 and 2015.

<table>
<thead>
<tr>
<th>Type of fuel</th>
<th>Scheduled year</th>
<th>Capacity (MW)</th>
<th>Location</th>
<th>Realized?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>2012</td>
<td>660</td>
<td>Jorf Lasfar (extension) Not specified</td>
<td>Not yet</td>
</tr>
<tr>
<td></td>
<td>2013 - 2015</td>
<td>2,600</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas</td>
<td>2009 / 2010</td>
<td>472</td>
<td>Ain Ben Mathar</td>
<td>Yes</td>
</tr>
<tr>
<td>Fuel Oil</td>
<td>2009</td>
<td>116 / 300</td>
<td>Agadir / Kenitra</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>2010</td>
<td>80</td>
<td>Agadir</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>2011</td>
<td>300</td>
<td>Kenitra</td>
<td>Yes</td>
</tr>
<tr>
<td>Hydro</td>
<td>2009</td>
<td>40</td>
<td>Tanafnit</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>2012</td>
<td>412 / 34</td>
<td>Abdelmoumen / Tillouguit</td>
<td>Not yet</td>
</tr>
<tr>
<td>Wind</td>
<td>2009</td>
<td>140</td>
<td>Tanger</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td>2010</td>
<td>200</td>
<td>Tarfaya</td>
<td>Yes (delayed)</td>
</tr>
<tr>
<td></td>
<td>2010 / 2011 / 2012</td>
<td>200 / 400 / 400</td>
<td>Not specified</td>
<td>No / No / Not yet</td>
</tr>
</tbody>
</table>

Table 2: National capacity addition until 2015 - strategy of 2008
Source: own elaboration based on (MEMEE, 2009a)

During the 2\textsuperscript{nd} national energy convention in 2010 the Minister of Energy, Mines, Water and Environment announced an updated energy strategy. The overall aims of this strategy are the “...”

\textsuperscript{16} The fact that production costs are high compared to end-consumer prices (low margin for ONE) is supported by the fact that ONE received financial help of 209 million EUR from the Moroccan Government in 2009 in order to remain liquid. This indicates that the actual electricity costs are higher than the revenues achieved (Jäger, 2009; Zingerle, 2010).
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security of supply in various types of energy; [and] their availability as well as their accessibility at fair, affordable prices ...”17. The strategy strongly relates to findings and approaches of the 2008 strategy. However, the stronger focus on exploitation of RE is new. On the one hand, the major milestone for wind energy is to achieve 2000 MW of capacity until 202018. On the other hand, the Moroccan Solar Plan was announced envisaging the employment of 2000 MW of solar energy until 2020.

Aims and Locations

The major strategic aims of the MSP are (Benkhadra, 2010):

- Diversification of energy supply
- Preservation of environment
- Exploitation of domestic renewable energy resources
- Reduction of energy dependency19

The plan proposes the use of the “...most up-to-date technologies currently available in the field of solar thermodynamic and photovoltaic...”20. The solar technology is supposed to be employed in five different sites in Morocco: Ouarzazate (500 MW), Ain Ben Mathar (400 MW), Boujdour (100 MW), Tarfaya (500 MW) and Laayoune (500 MW) (MASEN, 2010a). For better orientation all location are depicted in a map in Figure 7.

---

18 The target for wind power was accordingly increased from 1440 MW to 2000 MW installed capacity compared to the 2008 strategy. The Integrated Moroccan Wind Program foresees wind farms in Tarfaya (300 MW), Akhfenir (200 MW), Laayoune (50 MW), Haouma (50 MW), Tetouan (120 MW), Taza (150 MW), Koudia El Baida (300 MW), Tiskrad (300 MW) and Boujdour (100 MW) (Benkhadra, 2010).
19 The dependency on foreign energy supply in Morocco is high: 97.5% of the primary energy is imported (MEMEE, 2009). This dependency renders Morocco highly vulnerable to international market prices. In 2008 the subsidies for petroleum products increased for example to 2.05 billion EUR.
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Table 3 briefly describes the location, grid connection and water availability of each site and displays the approximate coordinates. The coordinates are used for the determination of the solar irradiation in chapter 3.

<table>
<thead>
<tr>
<th>Site</th>
<th>Location</th>
<th>Coordinates (lat. / long.) and elevation</th>
<th>Grid connection</th>
<th>Water availability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ouarzazate</td>
<td>7 kilometers to the northeast of Ouarzazate, on road P32</td>
<td>30.999 / -6.900 1187 m</td>
<td>225/60 kV</td>
<td>Mansour Eddahbi dam in 4 kilometers distance</td>
</tr>
<tr>
<td>Ain Ben Mathar</td>
<td>84 kilometers to the south of the city of Oujda</td>
<td>34.000 / -2.020 924 m</td>
<td>400/225 kV</td>
<td>aquifer allows to cover water needs</td>
</tr>
<tr>
<td>Boujdour</td>
<td>4 Kilometers (2.5 miles) to the north of Boujdour</td>
<td>26.100 / -14.470 55m</td>
<td>225/60 kV</td>
<td>3 kilometers to the sea</td>
</tr>
<tr>
<td>Tarfaya</td>
<td>south of the city of Tarfaya</td>
<td>27.150 / -13.200 69 m</td>
<td>225 kV, future 400 kV</td>
<td>11 kilometers (6.88 miles) to the ocean</td>
</tr>
<tr>
<td>Laayoune</td>
<td>south of Foum El Oued</td>
<td>27.930 / -12.930 7 m</td>
<td>225/60 kV, future 400 kV</td>
<td>2 to 3 Kilometers to the ocean</td>
</tr>
</tbody>
</table>

Table 3: Description of sites for solar power plants within the MSP
Source: own elaboration according to (MASEN, 2010a; HelioClim, 2011)

Organization and Procedures

The Moroccan Agency for Solar Energy (MASEN) is responsible for the fulfillment of the MSP and works in cooperation with ONE and MEMEE. It is in charge of tendering the single stages of site development, of financing the projects and is responsible for the development of the strategic orientation of the MSP (technology choice, time schedule etc.). MASEN will contract national or international consortia of companies delegating the construction of the power plants. In the final bidding process each applying consortium offers a price per kWh at which the electricity can be produced (PPA price). The best offer wins the bid. The electricity production will be sold by MASEN for a fixed tariff to ONE - also in form of a PPA. The difference between the PPA prices will be financed by MASEN with the financial help of MEMEE, the Hassan Fund II and private and international donors (i.e. soft loan / private loans). Whether, the end consumer is to be taxed by the Moroccan Government in order to contribute in covering the DC remains a possible, but so far not seriously discussed option. A summary of the relation between different actors within the MSP is sketched in Figure 8.

---

21 The coordinates have been selected according to the project location described by MASEN and may not represent the exact, but approximate site locations. Elevation data was taken from the automatic georeferencing model of HelioClim which is provided together with the irradiation data (HelioClim, 2011).
Actual Status

The exact construction dates for the single plants are not yet defined. The only fixed dates are the construction of the first and last stage in Ouarzazate which are in 2014 and 2015 respectively and the finalization of the whole project in 2020. Single project sizes are likely to range between 100 - 200 MW of capacity. Therefore, three development stages per site seem to be realistic. So far the first stage of 125 - 160 MW in Ouarzazate is in the final bidding process. Four consortia have been pre-qualified for designing, constructing, operating and maintaining the first CSP parabolic trough power plant in Ouarzazate (MASEN, 2010). The final offer is still being evaluated and the selection of one consortium is delayed, but can be expected for the first half of 2012. For the first phase in Ouarzazate only CSP parabolic trough has been considered as technology. However, future bidding processes will be open to other technologies such as PV or CSP tower technology.

So far MASEN received some financial support from different institutions: in November 2012 a loan of 200 million dollar was granted from the International Bank for Reconstruction and Development and a 97 million dollar loan from the Clean Technology Fund of the World Bank. Additional 15 million EUR is provided by the German Bank of Development (KfW) under the framework of the Climate Protection Initiative of the German Government.

22 The following companies are in the four consortia: 1. Abeinsa ICI, Abengoa Solar, Mitsui and Abu Dahbi NEC; 2. ENEL and ACS SCE; 3. International Company for Water and Power (ACWA), Aries IS and TSK EE; 4. Orascom CI Solar Millenium and Evonik Steag.

23 In beginning of 2012 it was announced that Solar Millenium is bankrupt. The company is member of one of the consortia and its financial problem might delay decision-making at MASEN.
3 Solar Resource in Sites of the MSP

3.1 Radiation Basics

This master thesis simulates solar power plants. Therefore, the most important variable in the equation of power production is the solar irradiation coming from the sun and received by the CSP-collectors and PV-panels. This section defines some terms which are used in the further analysis of the solar resource in the locations of the MSP. Some basic definitions - partly adopted from (Duffie/Beckmann, 1991) - are depicted in Table 4.

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
<th>Symbol ; Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Irradiance</td>
<td>The rate at which radiant energy is incident on a surface, per unit area of surface.</td>
<td>$G$ ; W/m²</td>
</tr>
<tr>
<td>Irradiation</td>
<td>The incident energy per unit area on a surface over a specified time (i.e. one hour, day).</td>
<td>$I$ ; l/m²</td>
</tr>
<tr>
<td></td>
<td>- On the horizontal</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- On a tilted surface</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Normal to a surface</td>
<td></td>
</tr>
<tr>
<td>Beam Radiation</td>
<td>Solar irradiation received by sun without scattering by i.e. clouds.</td>
<td>$b$ (subscript)</td>
</tr>
<tr>
<td>Diffuse Radiation</td>
<td>Solar irradiation received by sun after scattering (and change of direction) by the atmosphere.</td>
<td>$d$ (subscript)</td>
</tr>
<tr>
<td>Global Solar Radiation</td>
<td>Sum of beam and diffuse radiation.</td>
<td>$g$ (subscript)</td>
</tr>
<tr>
<td>Direct Normal Irradiation (DNI)</td>
<td>Beam irradiation perpendicular to a surface.</td>
<td>$I_{b,n}$ ; W/m²</td>
</tr>
<tr>
<td>Global Horizontal Irradiation (GHI)</td>
<td>Global irradiation on a horizontal surface.</td>
<td>$I_{g,h}$ ; W/m²</td>
</tr>
</tbody>
</table>

Table 4: Basic terms of solar radiation

Source: own elaboration partly adopted from (Duffie/Beckmann, 1991)

The earth receives an irradiance of 1367 W/m² from the sun. Variation of this irradiance occurs due to sunspot activities and changes of the earth-sun distance during the year. However, for engineering purposes energy emission from the sun is usually assumed to be constant (Duffie/Beckmann, 1991). Irradiation received by the earth’s surface which can be used for power generation in solar plants varies more significantly due to two main factors (Duffie/Beckmann, 1991):

1) Atmospheric scattering: The interaction of radiation with particles in the atmosphere such as air molecules, dust and water (vapor or droplets). The degree of scattering depends on the number of particles and its size relative to the wavelength of the radiation. The bigger the air mass to be traveled the more particles cause scattering. The higher the scattering, the lower is the radiation received on the earth’s surface and the lower is the transmittance of

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24 Air mass = mass of atmosphere through which the radiation actually passes given a certain sun elevation over the mass to be passed if the sun would be at its zenith (Duffie/Beckmann, 1991).
the atmosphere. The scattered sunlight is called diffused radiation as it changed its’ direction in contrary to the beam radiation.

2) **Atmospheric absorption**: Is mainly caused by ozone (O₃), water vapor (H₂O) and carbon dioxide (CO₂). These molecules absorb radiation of different wavelength defining the actual spectral distribution of the irradiation on the earth’s surface. The energy absorbed from the sunlight is used to excite the absorbing molecule and is lost for usage on the earth’s surface.

Both factors are highly dependent on local weather and atmospheric conditions. On cloudy days for example there is more scattering and absorption due to a high number of particles in the air leading to more diffused and less beam radiation compared to clear sky conditions.

For the purpose of modeling solar radiation on the earth’s surface different “Clear-Sky” models have been developed. This way the diffused and beam radiation can be approximated for a certain location. Time periods can be characterized by a clearness index which indicates the ratio of beam and extraterrestrial and implicitly the diffused fraction of radiation (Duffie/Beckmann, 1991). Both concepts are used in the determination of irradiation by satellite data which is described in the next section.

### 3.2 Data Sources

There are generally three different methods to estimate the solar resource in a specific location: The first one is to conduct ground measurements, the second is to conclude radiation based on satellite observations and the third one is stochastic modeling based on measured average values.

For this master thesis only sources providing the solar data free of charge and at least in hourly resolution have been consulted. Ground measurements are not yet available for the sites of the MSP. Therefore, only two sources have been used providing satellite data and stochastic modeling results:

- **HelioClim**: provided by the Solar Radiation Data service (HelioClim, 2011)
- **METEONORM**: software licensed for University of Kassel (Meteonorm, 2011)

To understand the methodology of the derived data the two methods are described briefly:

**HelioClim**: For the model calculations in this work HelioClim 3 (HC 3) data is used being freely available in hourly resolution for the year 2005. For comparison in this chapter also long-term HelioClim 1 (HC 1) data has been analyzed (freely available from 1985 - 2004 in monthly values). The difference of both data is the spatial and temporal resolution of images (20 km range and daily images for HC 1; 3 km and 15 minute images for HC 3; see (HelioClim, 2011)).

The HelioClim databases are estimated from the Meteosat Second Generation images. For estimation of radiation values the HelioSat-2 method developed by the Center for Energy and
Processes (MINES ParisTech / ARMINES) is used. The satellite images are taken from the orbit and each pixel on the picture is compared with the observation over that same pixel under clear-sky conditions. Basically the ground albedo under clear-sky is compared to the actual albedo deriving a cloud index. Clouds increase the apparent albedo and lower the transmittance of the atmosphere. The cloud-index relates to a value for the clear sky-index from which the actual irradiation can be derived if the irradiation under clear-sky conditions is known (Rigollier/Wald, 1998).

The validation shows that deviation of satellite data from ground measurements may be significant. However, as no measurement data is available for the sites of the MSP, HelioClim Data is taken for the later calculations.

Meteonorm: Data for every combination of longitude and latitude can be obtained by the program in different temporal resolutions. For this study hourly data has been generated.

The software uses measured data from meteorological stations. For locations outside a radius of 50 km around the closest weather station the program interpolates between two available stations. Meteonorm only stores interpolated monthly mean values from long-term measurements (usually period from 1981 - 2000). In order to obtain hourly time series of radiation stochastic models are used. These models generate data with similar statistical properties as the measured data (average values, variance or characteristic sequence). To obtain the hourly data an average daily profile of radiation is generated which depends on daily clear-sky index values and sun altitude. Meteonorm optionally delivers wind speed and temperature data with every data set of radiation (Meteonorm, 2011).

3.3 Solar Resource in Sites of the MSP

For each location of the MSP three data sets are obtained: One set of long-term monthly data indicating long-term variability of the solar resource, one set with hourly data of 2005 (both HelioClim), and one set of hourly values derived from long-term monthly averages by Meteonorm (reference period 1981 - 2000). The data sets are described in Table 5.

The data obtained contains DNI for CSP and extraterrestrial, beam and diffused irradiation on a horizontal plane for the simulation of PV. Hourly wind speed and ambient temperature (summarized in appendix B) is taken from Meteonorm as HelioClim does not provide this data.

---

25 Validation of hourly results with measurement data from 35 meteorological stations yields a Root Mean Square Error of 18% - 45%. Errors for daily irradiation or its monthly mean are lower ranging between 10% - 20% and 5% - 24% respectively for the same data (Rigollier, 2004).

26 The accuracy of this interpolation process is within the range of 9% - 14% Root Mean Square Error for monthly, global irradiation depending on the method used. For Morocco only measurement data of two meteorological stations are available in the Meteonorm database. Both are far from sites of the MSP.
Solar Resource in Sites of the MSP

<table>
<thead>
<tr>
<th>Source</th>
<th>Spatial resolution</th>
<th>Temporal resolution</th>
<th>Time period covered</th>
<th>Method and data set</th>
<th>Type of irradiation</th>
<th>Use in this study</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>HelioClim - hourly</strong></td>
<td>3 km</td>
<td>hourly</td>
<td>1/1/2005 - 31/12/2005</td>
<td>HelioSat-2, HC-3</td>
<td>Diffused, beam and extraterrestrial on horizontal, DNI ($I_{bh}, I_{dh}, I_{oh}$)</td>
<td>For all simulations of power plants</td>
</tr>
<tr>
<td><strong>HelioClim - long term average</strong></td>
<td>20 km</td>
<td>annual averages</td>
<td>1985 - 2004</td>
<td>HelioSat-2, HC-1</td>
<td></td>
<td>Comparison only in this chapter</td>
</tr>
<tr>
<td><strong>Meteonorm</strong></td>
<td>-</td>
<td>hourly</td>
<td>one exemplary year</td>
<td>Stochastic models</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 5: Obtained datasets of solar radiation for sites of the MSP
Source: own elaboration based on (Rigollier, 2004)

DNI

Long-term average yearly DNI (years 1985 - 2004) is taken from HelioClim for Ouarzazate, Ain Ben Mathar, Boujdour, Tarfaya and Laayoune ranges from 2,155 - 2,475 kWh/m²/y. For modeling purposes the annual sum of hourly irradiation should be close to the long-term average in order to deliver representative model results neither referring to years of very high nor very low annual irradiation. Unfortunately all obtained hourly data differs from the long-term HelioClim averages. HelioClim data for 2005 ranges for all sites between 1,927 and 2,428 kWh/m²/y. Data for Ouarzazate, Boujdour and Tarfaya deviates between +10.2 and -11.6% from the long-term data. For Ain Ben Mathar and Laayoune the irradiation in 2005 matches the long-term average very well (only +3.86% and +1.57% deviation respectively; see Table 6).

The data from Meteonorm deviates even stronger from the long-term averages of HelioClim (between -23.0% and +22.6%). Additionally, the Meteonorm data shows greater differences between the sites than HelioClim data: Ouarzazate for example has a DNI of 2,701 kWh/m²/y and Tarfaya only 1,677 kWh/m²/y (see Table 6). This spread has not confirmed to be true, neither from governmental information estimating irradiation at 2,635 kWh/m²/y in Ouarzazate and 2,140 kWh/m²/y in Tarfaya, nor from available irradiation maps (DLR, 2005; MEMEE, 2009). Therefore, for the present study the HelioClim data of 2005 are used as they seem to be more reliable.

![Table 6: DNI for sites of the MSP according to HelioClim and Meteonorm](source)
Source: own elaboration, data from (HelioClim, 2011; Meteonorm, 2011)
GHI

The long-term averages of GHI from HelioClim vary between 1,968 kWh/m²/y and 2,154 kWh/m²/y for the different sites of the MSP. Table 7 shows all gathered data at a glance. Apparently there is a better match between the long-term data and the hourly data of HelioClim for 2005 (deviation between -1.5% and +8.6%) and Meteonorm (deviation between -5.7% and 11.1%) compared to DNI. Very good matches occur for Boujdour, Tarfaya and Laayoune (-1.5% - 3.1%). Despite improved matching of Meteonorm data, HelioClim 2005 GHI is used for the modeling to have the same source of data for CSP and PV.

<table>
<thead>
<tr>
<th>Site</th>
<th>(1) HelioClim long-term average</th>
<th>(2) HelioClim 2005</th>
<th>(3) Meteonorm</th>
<th>(2) compared to (1)</th>
<th>(3) compared to (1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ouarzazate</td>
<td>1968</td>
<td>2136</td>
<td>2186</td>
<td>8.6%</td>
<td>11.1%</td>
</tr>
<tr>
<td>Ain Ben Mathar</td>
<td>1929</td>
<td>2028</td>
<td>1970</td>
<td>5.1%</td>
<td>2.2%</td>
</tr>
<tr>
<td>Boujdour</td>
<td>2154</td>
<td>2122</td>
<td>2030</td>
<td>-1.5%</td>
<td>-5.7%</td>
</tr>
<tr>
<td>Tarfaya</td>
<td>2038</td>
<td>2101</td>
<td>1935</td>
<td>3.1%</td>
<td>-5.1%</td>
</tr>
<tr>
<td>Laayoune</td>
<td>1959</td>
<td>1955</td>
<td>1898</td>
<td>-0.2%</td>
<td>-3.1%</td>
</tr>
</tbody>
</table>

Table 7: GHI for sites of the MSP according to HelioClim and Meteonorm
Source: own elaboration, data from (HelioClim, 2011; Meteonorm, 2011)

To conclude the solar resource analysis Figure 9 shows the annual variability and the monthly mean of DNI and GHI exemplarily for Ouarzazate. In general GHI shows lower variability than DNI. The highest daily averages occur during April for 2005 DNI and one to two month later for GHI.

Figure 9: Yearly irradiation (left) and monthly mean of daily irradiation (right) in Ouarzazate
Source: own elaboration, data from (HelioClim, 2011)
4 Technical Model

4.1 CSP: Solar Multiple 1-4

In this chapter the technical modeling of the parabolic trough CSP plant is described. Parabolic trough technology has been selected among other CSP technologies (i.e. Fresnel, Stirling Dish, Tower), because it is the most advanced technology in terms of market maturity and bankability. There is already around 350 MW installed parabolic trough capacity in the USA and about thirty 50 MW plants are operating or under construction in Spain. Fresnel and tower technology are less commonly employed and if so, in much smaller plant size. A higher technological risk and costs can be expected for up-scaling the plants compared to parabolic trough (Trieb, 2011).

MASEN also investigates the possibility of employing tower technology and is actually searching for technical assistance on this issue. Thus, future CSP plants within the MSP might also represent tower technology. However, a large number of plants will most likely employ parabolic trough technology. Thermal energy storage (TES) will definitely play a crucial role within the MSP (Amrane, 2011).

![Figure 10: Outline of the CSP thesis model](Source: own elaboration)

The modeling of a 50 MW reference CSP plant is based on a simplified approach (see Figure 10 for an energy flow diagram and an overview of the methodology). The complete simulation is described in the following three subsections. Firstly, the solar field (SF) is modeled: Geometrical, optical, thermal...
and field losses are subtracted from the hourly solar irradiation. The remaining energy per m² is then multiplied by the SF aperture area which depends on the SM of the plant. The result is a value for the total solar thermal output of the SF for each hour. Secondly, the TES for SM 2 - 4 is described. It is charged, if excess energy from the SF is available and discharged in case the SF cannot satisfy the load requirements of the power block (PB) for full load operation. Thirdly, the PB-model is set up by defining the rankine cycle and generator efficiency. Finally, parasitics depending on the type of cooling are subtracted to reach at the net power output.

The model uses different simplifying assumptions in order to keep the model as simple as possible and as detailed as necessary for this work. The model is strongly based on a CSP-model developed by the DLR and presented in (Trieb, 2004). Most formulas used are taken from this source.

4.1.1 Solar Field

Geometrical losses occur due to COS-losses, incidence angle modifier (IAM) losses, shading losses and row end losses. All losses are calculated on an hourly basis.

1. COS-Losses occur if the sun rays are not perpendicular to the aperture area of the collector. To calculate the angle of incidence (= the angle between the normal of the aperture area and the incident sun rays) the position of the sun must be known at all times. The cosine of the incidence angle equals the COS-loss coefficient. The formula used to calculate the COS-loss coefficient (cos\(\theta\)) yields (Duffie/Beckmann, 1991):

\[
\cos \theta = \cos \theta_z \cos \beta + \sin \theta_z \sin \beta \cos(|\gamma_S - \gamma|) \tag{4.1}
\]

Where, \(\theta\) = incidence angle, \(\theta_z\) = zenith angle, \(\beta\) = tilt angle, \(\gamma_S\) = solar azimuth angle, \(\gamma\) = surface azimuth angle. The formulas used to apply the involved solar geometry to find the incidence angle are listed in appendix C.

2. The IAM accounts for additional losses. If the incidence angle is greater than zero the sun image reflected on the absorber tube changes from being perfectly circular to an ellipse. As the tube is optimized to match a certain size (maximizing intercepted radiation and minimizing the area opposed to heat losses) not all of the radiation can be absorbed. This effect is greater for higher incidence angles. The definition and the formula for the IAM-loss coefficient (IAM\(_C\)) are taken from (Trieb, 2004). The latter yields:

\[
IAM_C = \cos \theta \left(1 + \sin^3 \theta\right) \tag{4.2}
\]

3. Shading losses occur usually in morning and evening hours when sun elevation is low and sun rays are coming from east and west. Then, one row of collectors may shade another row.
During dawn or dusk these losses can account for 100%. However, as distance between collector rows in this model is large, shading only occurs in few hours\(^{27}\). The shading loss coefficient \(S_C\) according to (Hoyer, 1998) are approximated by:

\[
S_C = 1 - \left(1 - \frac{R}{H(\cos \beta + \frac{\cos(\gamma_s - \gamma)}{\tan(\theta_s - \theta_s') \sin \beta})} \right) \left(1 - \frac{H \sin \beta \frac{\cos(\gamma_s - \gamma)}{\tan(\theta_s - \theta_s') \sin \beta} R}{L_C} \right)
\]

Where, \(R = \text{Distance of collector rows} = 17.6\) m, \(H = \text{Height of collector rows} = 5.76\) m, \(L_C = \text{Length of collector row} = 99\) m; for angles related to solar geometry see appendix C.

4) The last part of simulated geometrical losses represents the row end losses. They occur if the sunrays are not vertically on the aperture area. Then, on one side of the row the reflected radiation cannot hit the absorber pipe and on the other side, a part of the absorber pipe does not receive any radiation at all. Losses are high if sunrays are in parallel with absorber pipe direction and sun elevation is low (Trieb, 2004). According to (Hoyer, 1998) the row end loss coefficient \(R_C\) can be derived from:

\[
R_C = 1 - \frac{|f \tan \theta \sin |\gamma_s - \gamma| |}{L_C}
\]

Where, \(f = \text{focal length of the collector} = 2.12\), \(L_C = \text{Length of collector row} = 99\) m; angles related to solar geometry see appendix C.

To get the overall geometrical efficiency \(\eta_{SF,geo}\) of the SF:

\[
\eta_{SF,geo} = \cos \theta IAMC S_C R_C
\]

Optical losses occur i.e. due to imperfect reflection, transmission and absorption of the collectors. For the sake of simplicity of the model all optical losses are approximated by constant coefficients. They remain constant throughout the whole simulation and are assumed to be constant throughout the whole plant lifetime. In reality values may vary: reflection of mirrors for example changes due to varying dirt on the surface or due to aging. All coefficients and average values assumed for the simulation are summarized and described briefly in Table 8. They have been taken from (Trieb, 2004). As all coefficients are constant, the optical efficiency of collectors in the SF is assumed to be:

\[
\eta_{SF,opt} = \varepsilon_T \theta \mu \rho m \sigma \tau = 0.7329
\]

\(^{27}\) The arrangement of mirrors in the solar field is from north to south with a distance between the collector rows of 17.6 m. For the simulation LS-2 collectors are chosen with a height of 5.76 m and 99 m length (see (Trieb, 2004)).
Where, the coefficients stand for: \( \varepsilon_T = \) reflection of mirrors = 0.93, \( \vartheta = \) dirt on mirrors = 0.98, \( \mu = \) transmission of mirrors = 0.99, \( \rho_m = \) quality of mirrors = 0.9, \( \sigma_T = \) transmission of cover = 0.95, \( \tau = \) absorption of absorber pipe = 0.95.

<table>
<thead>
<tr>
<th>Symbol/Value</th>
<th>Name of coefficient</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \varepsilon_T = 0.93 )</td>
<td>Reflection of mirrors</td>
<td>Average reflection coefficient of mirrors. Not all radiation can be reflected by the mirrors, thus, losses occur.</td>
</tr>
<tr>
<td>( \vartheta = 0.98 )</td>
<td>Dirt on mirrors</td>
<td>Dirt on the mirror surface reduces reflection. Despite of frequent washing an average loss of 2% can be assumed.</td>
</tr>
<tr>
<td>( \mu = 0.99 )</td>
<td>Transmission of mirrors</td>
<td>The glass cover of the reflective silver layer of the mirror absorbs a part of the radiation which is then lost for use.</td>
</tr>
<tr>
<td>( \rho_m = 0.90 )</td>
<td>Quality of mirrors</td>
<td>Manufacturing errors affect mirrors so that reflections do not form a precise focal point, thus radiation misses the absorber pipe.</td>
</tr>
<tr>
<td>( \sigma_T = 0.95 )</td>
<td>Transmission of cover</td>
<td>To reduce heat losses the absorber pipe is sheltered by a glass cover which is not able to transmit all radiation.</td>
</tr>
<tr>
<td>( \tau = 0.95 )</td>
<td>Absorption of absorber pipe</td>
<td>Also the absorber pipe does not absorb all, but reflects some radiation which leads to further losses.</td>
</tr>
</tbody>
</table>

Table 8: Optical loss coefficients of collectors
Source: own elaboration based on (Trieb, 2004)

The heated transfer fluid in the absorber pipe is subject to thermal losses by radiation and convection. Conduction losses only play a minor role and are neglected.\(^{28}\)

(1) Radiation losses occur if a body has a higher temperature than a surrounding body. Energy radiates from the source with higher temperature \( (T_1) \) to the colder body \( (T_2) \). Assuming that the latter behaves like a black body the heat flow \( (q) \) can be approximated by the following formula (Trieb, 2004):

\[
q = \sigma \varepsilon A \left( T_1^4 - T_2^4 \right)
\]

Where, \( \sigma \) represents the Stefan-Boltzmann-constant \( (\sigma = 5.67 \times 10^{-8} \text{ W/m}^2\text{K}^4) \). The amount of energy transferred depends on the area of the radiating body \( (A) \) and the emissivity of the material \( (\varepsilon) \). In the case of absorber pipes in parabolic trough collectors a ceramic-metal coating can be used with an emission coefficient of \( \varepsilon = 0.08 \) (assumed to be constant, see (Trieb, 2004)).

To get a number for the thermal losses the absorber area needs to be known. It can be derived by the following equation given the geometrical concentration ratio \( (C, \text{ ratio between aperture area of collector and the area of the sun image on the absorber}) \) and assuming an absorber with the same size as the sun image:

\(^{28}\) For a more detailed simulation of heat transfer losses at absorber pipes see (Bekhit, 2011).
\[ C = \frac{Dc \cdot Lc}{d_{Abs} \cdot Lc} \] 4.8

Where: \( Lc \) = length of collector, \( Dc \) = the height of collector and \( d_{Abs} \) = diameter of the absorber.

Given the concentration ratio (here, \( C = 71 \)) and being aware that \( A_{Abs} = \pi \cdot d_{Abs} \cdot L_{abs} \), rearranging and replacing delivers the absorber area \( (A_{abs}) \):

\[ A_{abs} = \pi \cdot Dc \cdot \frac{L_{abs}}{C} \] 4.9

Where, \( L_{abs} \) = temperature of the absorber.

Furthermore, it is assumed that there is no temperature difference between absorber and heat transfer fluid (HTF), the absorber cover behaves like a black body with a 37° higher temperature \( (T_{cover}) \) than the ambience \( (T_a) \) and that convection from cover to ambient air occurs without losses \( (T_{cover} = T_a + 37 ^\circ C) \).

The radiation losses \( (q_R) \) can then be approximated by the following equation (Trieb, 2004):

\[ q_R = \pi \cdot \frac{1}{C} \cdot (T^4 - T_{Cover}^4) \] 4.10

Where, \( T = \frac{T_{in} + T_{out}}{2} \) is the average temperature of the HTF with \( T_{in} = 298 ^\circ C \) and \( T_{out} = 390 ^\circ C \).

Additionally, it is assumed that \( T \) is constant during plant simulation and that fluctuation of available heat from the SF (normally altering the HTF temperature) are balanced by changing the mass flow of HTF through the absorber pipe.

Convection losses represent an average value for absorber unit and other piping losses. Convection only occurs at small absorber pipe areas without coverage. As the cover is evacuated convection in these areas is negligible. Natural convection\(^{29}\) depends on loss the coefficient of the absorber and piping \( (U = 2 \cdot \frac{W}{m^2 \cdot K}) \) and the temperature difference to the ambience \( (T_{abs} - T_a) \). The used formula yields:

\[ q_c = \frac{U \cdot \pi}{C} \cdot (T_{abs} - T_a) \] 4.11

The radiation and convection losses are calculated in absolute terms (in W). To get a value for the thermal efficiency, the hourly sum of both losses is divided by the hourly DNI \( (I_{b,n}) \) and subtracted from unity. Thermal efficiency \( (\eta_{SF,th}) \) thus, yields:

\(^{29}\) At this place forced convection (i.e. by wind) is neglected, but is considered within the field loss coefficient later on.
Finally, the field loss coefficient accounts for additional convective heat losses given strong winds (forced convection), availability of collectors (assumed to be 99.5%) and losses in connections and piping (assumed to be 99%). The losses due to high wind speed are expressed by the following empirical relation: 
\[ f_w = 1.125 - 0.0083 \nu_W \]
where, \( \nu_W \) = wind speed. The field loss coefficient (\( \varpi \)) is then (Trieb, 2004):
\[ \varpi = 0.98505 f_w \]

The overall SF efficiency is finally comprised of geometrical efficiency, optical efficiency, thermal efficiency and field loss coefficient. It is an important parameter to judge the efficiency of the SF throughout the year. In the simulation it is calculated on an hourly base. The formula for the SF efficiency (\( \eta_{SF} \)) is:
\[ \eta_{SF} = \eta_{SF,geo} \eta_{SF,opt} \eta_{SF,th} \varpi \]

### 4.1.2 Solar Multiple

The total heat supplied by the SF depends on the SM of the simulated power plant. The higher the SM the greater is the aperture area of mirrors in the SF. The simulated plant with SM 1 is serving as a reference for the basic field size. For the plants with SM 2, SM 3 and SM 4 the basic field size is simply multiplied by the factors 2, 3 and 4 respectively. The following description explains how the basic field size is derived.

In the context of this study it is assumed that the PB runs at nominal turbine load at a design point of 800 W/m\(^2\) of irradiance. The required SF size can be calculated if the SF output at the design point (\( SF_{DP} \)) is known. It is calculated for optimal conditions (no geometrical losses and no field losses, but optical and thermal losses) as follows:
\[ SF_{DP} = 800 \frac{W}{m^2} \eta_{SF,opt} \eta_{SF,th} = 524.6 \frac{W}{m^2} \]

Where, \( \eta_{SF,opt} = \) optical efficiency of SF = 0.7329, \( \eta_{SF,th} = \) thermal efficiency of SF = 0.8947\(^{30}\).

\(^{30}\) The value for the thermal efficiency is taken as reference for all locations under optimal conditions (no geometrical losses). The efficiency has been calculated within the validation model “El Paso” (see section 6.2) at hour 516 with approximately 800 W/m\(^2\) irradiance and thermal losses of 84.2 W/m\(^2\).
The thermal gross efficiency of the PB under full load operation is calculated in section 4.1.4. It is 36.5 % for dry cooling and 38.9 % for wet cooling plants. Thus, the PB output per m² of aperture area \((PBO_{DP})\) at the design point is:

- For dry cooling:
  \[
PBO_{DP,dry} = 524.6 \frac{W}{m^2} \times 36.5\% = 191.6 \frac{W}{m^2}
\]
- For wet cooling:
  \[
PBO_{DP,wet} = 524.6 \frac{W}{m^2} \times 38.9\% = 204.1 \frac{W}{m^2}
\]

The required aperture area for full load operation of the solar plant is then the nominal gross power output divided by the corresponding \(PBO_{DP}\) multiplied by the factor for the SM (1,2,3 or 4). All field sizes for a 50 MW reference plant are summarized in Table 9.

<table>
<thead>
<tr>
<th>Solar field size (m²)</th>
<th>Dry cooling</th>
<th>Wet cooling</th>
</tr>
</thead>
<tbody>
<tr>
<td>SM 1</td>
<td>260,998</td>
<td>245,030</td>
</tr>
<tr>
<td>SM 2</td>
<td>521,997</td>
<td>490,060</td>
</tr>
<tr>
<td>SM 3</td>
<td>782,995</td>
<td>735,090</td>
</tr>
<tr>
<td>SM 4</td>
<td>1,043,994</td>
<td>980,120</td>
</tr>
</tbody>
</table>

Table 9: Solar field size for all SM, 50 MW reference plant, 800 W/m² design point
Source: own elaboration

The thermal energy available \((q_{th, SF})\) from the SF for dispatch to the PB or to the TES of the plant is calculated as follows:

\[
q_{th, SF} = I_{b,n} \eta_{SF} A_{SF}
\]

Where, \(I_{b,n}\) = hourly DNI, \(\eta_{SF}\) = SF efficiency, \(A_{SF}\) = aperture area of SF.

4.1.3 Dispatch of Thermal Energy

In the case of SM 1 all the thermal energy from the SF directly goes to the PB. In hours with solar irradiation above the design point the SF produces excess energy. In times with low irradiation the plant runs on part load.

In the case of SM 2, 3 and 4 a TES with a capacity of 6, 12 and 18 full load hours is assumed. The required thermal energy for one full load hour \((q_{th, fth})\) is given by the gross electric output of the plant at full load divided by the PB efficiency. For a 50 MW reference plant it yields:
For dry cooling:

\[ q_{th, fh} = \frac{50 \, MW}{0.365} = 136.9 \, MW \]  

For wet cooling:

\[ q_{th, fh} = \frac{50 \, MW}{0.389} = 128.5 \, MW \]  

The required energy for one full load hour times the storage duration in full load hours is the assumed TES capacity which is displayed in Table 10 for all SMs over all sites.

<table>
<thead>
<tr>
<th>Thermal energy storage capacity (MWh)</th>
<th>SM 2</th>
<th>SM 3</th>
<th>SM 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry cooling</td>
<td>1,027</td>
<td>2,053</td>
<td>3,080</td>
</tr>
<tr>
<td>Wet cooling</td>
<td>964</td>
<td>1,928</td>
<td>2,892</td>
</tr>
</tbody>
</table>

Table 10: TES capacity of CSP plants
Source: own elaboration and calculation

The TES is based on a control mechanism to keep up certain dispatch conditions:

1. **"Must-run" order:** First of all, the basic requirement for the power plants with storage is to run during hours of peak load demand. The model allows for entering the last hour of the day in which energy should be produced by the plant. To make sure the peak load of the day is covered, power plants run until 23:00 throughout the year. As there is only a certain irradiation budget per day the total available irradiation is divided by the requirement of thermal energy for full load operation. Then the start time of plant operation is calculated by subtracting the result from the last “must-run” hour (23:00). If the result is smaller than the hour of the day, all energy goes into the TES for this hour. Otherwise the energy is generally available for the use in the PB.

2. The thermal energy available from the SF \( q_{th, SF} \) can either be completely or partly dispatched to the TES. The conditions for dispatch are as follows:

   a. **Thermal energy directly to the PB:**
      
      If
      \[ q_{th, SF} \leq q_{th, fh} \]
      , then
      \[ q_{th, SF} = q_{SF to PB} \]
      otherwise
      \[ q_{th, fh} = q_{SF to PB} \to PB \]
      
      Condition:
      \[ q_{th, SF} + q_{TES,out} \geq 25\% \times q_{th, fh} \]

   b. **Thermal energy to storage:**
      
      If
      \[ q_{th, SF} + q_{TES,out} < 25\% \times q_{th, fh} \]
      then
      \[ q_{th, SF} \to TES, \text{ and} \]
      
      if
      \[ q_{th, SF} - q_{th, fh} > 0 \]
      , then
      \[ q_{th, SF} - q_{th, fh} \to TES. \]
c. **Thermal Energy from storage to PB:**

If \( q_{th,filh} > q_{th, SF} \), then \( q_{TES,out} = q_{th,filh} - q_{th, SF} \) to PB.

**Condition:** \( q_{TES,stored} > q_{th,filh} - q_{th, SF} \), otherwise \( q_{TES,stored} = q_{TES,out} \) to PB.

Where, \( q_{th, SF} \) = thermal energy available from SF, \( q_{th,filh} \) = thermal energy required for full load operation of PB, \( q_{TES,out} \) = thermal energy from TES to PB, \( q_{TES,stored} \) = accumulated thermal energy in storage, \( q_{SF \rightarrow PB} \) = thermal energy from SF to PB.

The conditions guarantee that the energy from the SF and output from TES are greater than the minimum required thermal energy to operate the PB\(^{31}\) (condition in a). If the available energy and TES output are less than the minimum required, all energy is stored. Excess energy (more thermal energy available then needed for full load operation of the PB) also goes to the TES (condition in b). If the thermal power provided by the SF is less than required to operate in full load, available energy from TES is used to fill the gap (condition in c).

All energy which goes at any point into the TES is reduced by the storage efficiency which should account for energy losses occurring in the heat exchangers. Each heat exchange induces thermal energy losses in the order of 5% each, so that the total storage efficiency is 10%. Thermal energy which remains in the TES is also opposed to heat losses which are approximated similarly as in (SAM, 2011): The surface tank area \( A_{tank,s} \)^{32} times the heat loss coefficient \( h_{loss} = 0.4 \) \( W/m^2K \) of the tank material times the temperature difference between ambient air \( (T_a) \) and stored molten salt medium \( (T_{salt}) \) delivers the heat loss. It is weighed with the filling height of the tank represented by the ratio of stored thermal energy \( (q_{TES,stored}) \) to maximum storage capacity \( (q_{TES,max}) \). The formula yields:

\[
q_{TES,loss} = h_{loss} A_{tank,s} (T_a - T_{salt}) \left( \frac{q_{TES,stored}}{q_{TES,stored}} \right)
\]

(4.21)

The hourly sum of the thermal energy which goes directly from the SF to the PB \( (q_{SF \rightarrow PB}) \) and from TES to the PB \( (q_{TES,out}) \) is the total available heat into the PB \( (q_{in}) \):

\[
q_{in} = q_{SF \rightarrow PB} + q_{TES,out}
\]

(4.22)

\(^{31}\) For the simulations in this work, 25% of the required energy for one full load hour is considered to be the minimal, necessary energy to operate the power plant. However, the value can be changed in the model input data sheet.

\(^{32}\) Surface area has been adopted from (SAM, 2011) for a thermal storage of 6h, 12h and 18h for SM 2, SM 3 and SM 3 respectively.
The total available heat for the PB is used to run the thermodynamic cycle which is described in the next section.

4.1.4 Power Block

The modeling of the PB is also adopted from (Trieb, 2004). It does not model any processes in detail, but rather calculates the most important parameters in the PB in a simplified manner. The parameters taken into account are: Thermodynamic cycle efficiency (constant value), generator efficiency (part and full load behavior) and parasitics.

**Thermodynamic efficiency**

The model is based on an ideal Clausius-Rankine cycle assuming a constant thermodynamic efficiency. The cycle consists of four process steps and four different states of the working medium (Crastan, 2004):

1. 1-2: isentropic compression (increasing pressure to operating pressure)
2. 2-3: isobaric heat addition (heating, evaporation and superheating of working medium)
3. 3-4: isentropic expansion (creation of mechanical energy)
4. 4-1: isobaric heat removal (condensation of steam)

To assume an ideal cycle and a constant efficiency simplifies the analysis significantly. The suitability of these assumptions for approximate modeling purposes is shown in (Trieb, 2004) where the validation of the plant model shows good consistency with the real behavior of CSP-plants. However, regarding the two assumptions mentioned above, more explanation is needed:

1. **Ideal Clausius-Rankine cycle:**
   In reality the thermodynamic cycle of a CSP plant is not ideal. The changes of states of the working medium are irreversible (increase of entropy after turbine and pump, pressure loss in condenser and evaporator). Compared to the ideal cycle the thermal efficiency in reality is about 10 - 15% lower. However, in modern processes re- and pre-heating is used to increase cycle efficiency. (Trieb, 2004) claims that a typical process with simple pre-heating and double re-heating achieves 10 - 15% better efficiency than normal processes. Thus, an ideal simple Rankine cycle (with turbine, boiler, pump and condenser) yields similar efficiency values then a modern process, but is much easier to model.

2. **Constant cycle efficiency:** The efficiency of a cycle depends on the pressure and temperature achieved during the process. They usually vary and therefore the cycle efficiency varies. For this work it has been assumed that the efficiency is constant (thus, all operating pressures

---

33 State 1 is after condenser (isobaric heat removal), state 2 after pump (isentropic compression), state 3 after evaporator (isobaric heat addition) and state 4 after turbine (isentropic expansion).
and temperatures are constant). This implies the following assumptions: Firstly, instead of having varying steam temperatures due to varying input from SF and TES, the mass flow of the HTF is regulated. For example if few thermal energy from SF and TES is available, a lower mass flow of HTF is used to reach a constant temperature of the HTF at the inlet to the evaporator. Secondly, the mass flow of steam is also regulated as to have constant values for states in the cycle under varying power output. Thirdly, condensation temperature is assumed to be constant and independent from ambient temperatures.

To reach at the thermodynamic cycle efficiency all states of the cycles must be known. At the inlet to the evaporator the HTF is assumed to have a temperature of 390°. Assuming that the evaporator reaches a steam temperature of $T_1 = 371^\circ$C and a pump operating pressure of $p_2 = p_3 = 100$ bar state 3 is defined. From the T-s-diagram for steam given constant entropy $T_4 = T_1$ and $p_4 = p_3$. The condensation temperature depends on the used type of cooling system and is assumed to be $T_{\text{cond,dry}} = 53^\circ$C for dry cooling. For wet cooling it is $T_{\text{cond,wet}} = 35^\circ$C.\(^{34}\)

Given the condensation temperature and the pressure, state 4 is defined. Thus, all states are known and the corresponding specific enthalpies in all steps can be taken from a steam table. All state properties for wet (black values) and dry cooling (grey values) used in the model are summarized in Table 11.

<table>
<thead>
<tr>
<th>State</th>
<th>1 (after condenser)</th>
<th>2 (after pump)</th>
<th>3 (after evaporator)</th>
<th>4 (after turbine)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure (bar)</td>
<td>0.07</td>
<td>100</td>
<td>100</td>
<td>0.07</td>
</tr>
<tr>
<td></td>
<td>0.143</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature (°C)</td>
<td>35</td>
<td>35.3</td>
<td>371</td>
<td>35</td>
</tr>
<tr>
<td></td>
<td>53</td>
<td>53.4</td>
<td>371</td>
<td>53</td>
</tr>
<tr>
<td>Heat capacity (kJ/kgK)</td>
<td>4.179</td>
<td>4.154</td>
<td>3.499</td>
<td>4.179</td>
</tr>
<tr>
<td></td>
<td>4.180</td>
<td>4.158</td>
<td>3.499</td>
<td>4.18</td>
</tr>
<tr>
<td>Density (kg/m(^3))</td>
<td>994.0</td>
<td>998.3</td>
<td>41.3</td>
<td>0.1</td>
</tr>
<tr>
<td></td>
<td>986.6</td>
<td>990.7</td>
<td>41.3</td>
<td></td>
</tr>
<tr>
<td>Specific enthalpy (kJ/kg)</td>
<td>147</td>
<td>157</td>
<td>3002</td>
<td>1861</td>
</tr>
<tr>
<td></td>
<td>222</td>
<td>232</td>
<td>3002</td>
<td>1959</td>
</tr>
<tr>
<td>Specific volume (m(^3)/kg)</td>
<td>0.001</td>
<td>0.001</td>
<td>0.024</td>
<td>17.876</td>
</tr>
<tr>
<td></td>
<td>0.001</td>
<td>0.001</td>
<td>0.024</td>
<td>7.662</td>
</tr>
<tr>
<td>Specific entropy (kJ/kgK)</td>
<td>0.505</td>
<td>0.505</td>
<td>6.070</td>
<td>6.070</td>
</tr>
<tr>
<td></td>
<td>0.742</td>
<td>0.742</td>
<td>6.070</td>
<td></td>
</tr>
</tbody>
</table>

Table 11: Properties of the working fluid for wet (black) and dry cooling cycle (grey)
Source: own elaboration based on (Trieb, 2004)

To calculate the power output of the PB several calculation steps are necessary: Total heat added to the process ($q_{\text{in}}$) is determined by the output of the SF and TES system. To fulfill the full load

\(^{34}\) For details of derivation see (Trieb, 2004).
requirement of the plant a certain thermal load is required (shown for a 50 MW reference plant in section 4.1.3). Given this value the required mass flow of working fluid can be calculated as follows:

\[ m_{\text{steam}} = \frac{q_{\text{in}}}{(h_3 - h_2)} \]  

4.23

Where, \( h_3 \) = specific enthalpy in state 3 and \( h_2 \) = specific enthalpy in state 2.

Given the value for the mass flow of steam (\( m_{\text{steam}} \)) the actual power of the turbine (\( P_{\text{th}} \)) is:

\[ P_{\text{th}} = m_{\text{steam}}(h_3 - h_4) \]  

4.24

Where, \( h_4 \) = specific enthalpy in state 4.

The thermal efficiency of the cycle (\( \eta_{\text{cycle}} \)) is defined as ratio of turbine power and thermal energy input (Crastan, 2004):

\[ \eta_{\text{cycle}} = \frac{P_{\text{th}}}{q_{\text{in}}} = \frac{h_3 - h_4}{h_3 - h_2} \]  

4.25

The results for the thermal efficiencies used in this work are \( \eta_{\text{cycle}} = 36.52\% \) for dry cooling and \( \eta_{\text{cycle}} = 38.9\% \) for wet cooling (with values for the enthalpies taken from Table 11 for wet and dry cooling correspondingly). The difference in efficiency is due to the higher condensation temperature in the case of dry cooling.

**Generator efficiency**

The (part-load) generator efficiency (\( \eta_{\text{cycle}} \)) is approximated as follows (Trieb, 2004):

\[ \eta_{\text{G}} = \frac{P_{\text{th}}}{P_{\text{th,nom}}} - (1 - \eta_{\text{G,nom}}) \frac{P_{\text{th}}}{P_{\text{th,nom}}} \]  

4.26

Where, \( \eta_{\text{G,nom}} \) = generator efficiency at nominal load = 0.97.

The overall PB efficiency (\( \eta_{\text{PB}} \)) is then:

\[ \eta_{\text{PB}} = \eta_{\text{cycle}} \eta_{\text{G}} \]  

4.27

**Parasitics**

Every CSP plant has its own electrical power needs for example to run pumps, compressors or tracking systems. Within this work the parasitics of the SF and the PB have been modeled according to (Trieb, 2004). Procedure and formulas are listed in appendix D in order to shorten this section. In
general, parasitics depend on location, type of cooling and especially the SM of the plant. It varies roughly between 4% and 13% of nominal gross power output of the plant. Detailed results for all plants are summarized in appendix E.

Parasitics in this model include modeling the electricity consumption of:

- **General**: HTF pump (SF), tracking (SF) and stand-by of plant
- **Only for wet cooling**: Feed water pump (cooling circuit) and supply pump (transport of cooling water from source to plant)
- **Only for dry cooling**: Ventilation

### Gross and net power plant output

The gross power output ($P_{\text{gross}}$) of the simulated CSP plant is calculated given the thermal energy delivered from SF and TES ($q_{\text{in}}$) on an hourly basis as follows:

$$P_{\text{gross}} = q_{\text{in}} \eta_{PB} \tag{4.28}$$

The net power output ($P_{\text{net}}$) is the gross power output minus the parasitic load ($L_p$):

$$P_{\text{net}} = P_{\text{gross}} - L_p \tag{4.29}$$

### 4.2 PV: Fixed Tilted, Horizontal, Vertical and 2-axis Tracking

This chapter describes the modeling of the PV systems in this thesis. For the sake of comparison four different PV systems are modeled:

1. **Fixed tilted**: PV modules are orientated towards south with a tilt angle equal to the latitude.
2. **1-axis continuous horizontal tracking**: PV modules are tracked on a horizontal north-south axis with continuous adjustment for this axis.
3. **1-axis continuous vertical tracking**: PV modules are deployed with a tilt angle equal to the latitude and are tracked around the tilted, vertical axis by varying the surface azimuth angle.
4. **2-axis continuous tracking**: PV modules are tracked along their east-west and north-south axis so that the beam irradiation is at all times perpendicular to the module.

Each system (1, 2, 3 or 4) receives a different solar irradiation on the module due to the different orientation of the module. Based on the SANDIA module model (King, 2004) the annual PV-module efficiency and the temperature correction factor determine the power output of an array of the PV plant. The SANDIA inverter model is used to model the ac gross power output. An overview of the
main components of the PV module and an energy flow model is displayed in Figure 11. The calculation of the irradiation on the module and the SANDIA module and inverter models are explained in the next three sections.

4.2.1 Irradiation on the Module Plane

The aim in tracking PV system is to minimize the incidence angle of the sun rays on the module plane. For the exact positioning of the tracking system the slope and the surface azimuth angle must be known. They indicate the movement along the vertical and horizontal axis respectively. For each system the formulas to minimize the incidence angle and to calculate the slope and the surface azimuth angle are taken from (Duffie/Beckmann, 1991) and are listed in Table 12.

<table>
<thead>
<tr>
<th>System</th>
<th>Incidence Angle</th>
<th>Tilt angle</th>
<th>Surface azimuth angle</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>( \cos\theta = \cos\theta_z \cos\beta + \sin\theta_z \sin\beta \cos(\gamma_s - \gamma) )</td>
<td>( \beta = \text{constant} )</td>
<td>( \gamma = 0^\circ )</td>
</tr>
<tr>
<td>2</td>
<td>( \cos\theta = (\cos^2\theta_z \cos^2\delta \sin^2\omega)^{1/2} )</td>
<td>( \tan\beta = \tan\theta_z</td>
<td>\cos\gamma - \gamma_s</td>
</tr>
<tr>
<td>3</td>
<td>( \cos\theta = \cos\theta_z \cos\beta + \sin\theta_z \sin\beta )</td>
<td>( \beta = \text{constant} )</td>
<td>( \gamma = \gamma_s )</td>
</tr>
<tr>
<td>4</td>
<td>( \cos\theta = 1 )</td>
<td>( \beta = \alpha )</td>
<td>( \gamma = \gamma_s )</td>
</tr>
</tbody>
</table>

Table 12: Incidence, tilt and surface azimuth angle for all tracking systems

Source: own elaboration, formulas from (Duffie/Beckmann, 1991)
The data provided by HelioClim is DNI and beam and diffused irradiation on the horizontal. To calculate the direct beam irradiation on a sloped surface \((I_{b,t})\) the hourly COS-loss \((\cos \theta)\) coefficient of each system is multiplied by the DNI \((I_{b,n})\):

\[
I_{b,t} = I_{b,n} \cos \theta
\]

To get the diffused and reflected irradiation on a sloped surface, the anisotropic sky-model of Hay-Davis-Klucher-Reindl is used (HDKR-model). For diffused sky and horizon irradiation it yields (Duffie/Beckmann, 1991):

\[
I_{d,t} = I_{d,h}(1 - A_i)\left(\frac{1 + \cos \beta}{2}\right)(1 + f \sin^2(\frac{\beta}{2}))
\]

Where, \(A_i = \frac{I_{b,h}}{I_o}\) is an anisotropy index with \(I_o = \) extraterrestrial irradiation, \(f = \frac{I_{b,h}}{I_{g,h}}\) is a the modulating factor accounting for cloudiness (root of the ratio of direct beam irradiation and global irradiation on horizontal). The HDKR-model also accounts for circumsolar diffused irradiation \((I_{d,\text{circumsolar}})\):

\[
I_{d,\text{circumsolar}} = I_{d,h}A_iR_b
\]

Where, \(R_b = \frac{\cos \theta}{\cos \beta_2}\) accounting for geometric relation between sun and module surface.

For the reflected irradiation given the ground albedo \((p_g)\):

\[
I_{r,t} = I_{g,h}p_g\left(\frac{1 - \cos \beta}{2}\right)
\]

Thus, the total irradiation on the module is:

\[
I_{\text{total},t} = I_{b,t} + I_{d,t} + I_{d,\text{circumsolar}} + I_{r,t}
\]

### 4.2.2 DC Output - Array

The used SANDIA array performance model determines the PV-module array output. Firstly, it determines the maximum power point current and voltage of the module in dependence of the incident irradiation. Secondly, the resulting power for a complete array given a certain number of modules is calculated and corrected by a temperature correction factor. All equations in this section representing the PV model are taken from (King, 2004). For this study the PV module Yingli Solar
YL230-29b is used for the power plant simulation. The corresponding parameters needed for the SAMDIA performance model and the temperature correction factor are summarized in appendix E.\(^{35}\)

**Maximum power point**

To calculate the maximum power point current \((I_{mp})\) the following equation is used:

\[
I_{mp} = I_{mp0}(C_0 I_e + C_1 I_e^2)(1 + \alpha_{mp}(T_c - T_o))
\]  \(4.35\)

Where, the normalized temperature coefficient \((\alpha_{mp})\) corrects for deviation of actual cell temperature \((T_c)\) from temperature \((T_o)\) at standard testing conditions (STC)\(^{36}\). \(C_0\) and \(C_1\) are empirically determined coefficients relating the maximum power point current to effective irradiance \((I_e)\) which is determined by:

\[
I_e = I_{sc}/(I_{sc0}(1 + \alpha_{sc}(T_c - T_o)))
\]  \(4.36\)

Where, \(I_{sc0}\) is the short circuit current under STC and \(\alpha_{sc}\) the normalized temperature coefficient determining the variation of effective irradiance depending on to actual cell temperature. \(I_{sc}\) is the actual short circuit current given by:

\[
I_{sc} = I_{sc0}f_1(AM_a)((I_{b,t}f_2(\text{AOI}) + \frac{f_d I_d,I}{I_{ref}}(1 + \alpha_{sc}(T_c - T_o)))
\]  \(4.37\)

Where, \(I_{ref}\) = irradiation at STC, \(f_d\) = fraction of diffused irradiation, \(I_{b,t}\) = direct (beam) irradiation on the module and \(I_{d,t}\) = diffused irradiation on the module. The solar spectral influence on \(I_{sc}\) due to air mass variation is approximated by:

\[
f_1(AM_a) = a_0 + a_1 + a_2(AM_a)^2 + a_3(AM_a)^3 + a_4(AM_a)^4
\]  \(4.38\)

Where, \(a_0\) - \(a_4\) = empirically determined coefficients, \(AM_a\) = air mass.

The optical influence on \(I_{sc}\) due to solar angle of incidence is:

\[
f_2(\theta) = b_0 + b_1 \theta + b_2(\theta)^2 + b_3(\theta)^3 + b_4(\theta)^4 + b_5(\theta)^5
\]  \(4.39\)

Where, \(b_0\) - \(b_5\) = empirically determined coefficients, \(\theta\) = angle of incidence.

For the maximum power point voltage:

---

\(^{35}\) The model is capable of working with different PV modules. The only condition is that the parameters used in the models’ equations are available from empirical laboratory tests. For over 200 PV modules the parameters have been identified by SANDIA and are available in their module database.

\(^{36}\) The performance indicators (i.e., efficiency) of each module are usually tested under STC given the following conditions: Irradiance: 1000 W/m\(^2\), reference temperature: 25\(^\circ\)C, air mass = 1.5.
\[ V_{mp} = V_{mpo} + C_2 N_s \delta(T_c) \ln I_e + C_3 N_s (\delta(T_c) \ln I_e)^2 + \beta_{Vmp} I_e (T_c - T_o) \] 4.40

Where, \( C_2 \) and \( C_3 \) are empirical coefficients relating the maximum power voltage to effective irradiance, \( N_s \) the number of cells in series per string of modules, \( V_{mpo} \) the maximum power point voltage under STC and \( \beta_{Vmp} \) the temperature coefficient of the maximum power voltage. The thermal voltage \( \delta(T_c) \) in dependence of cell temperature is given by:

\[ \delta(T_c) = nk(T_c + 273.15)/q_e \] 4.41

Where, \( n = \) diode factor of module, \( k = \) Boltzmann’s constant and \( q_e = \) elementary charge.

The important equations for further calculations are the ones determining \( I_{mp} \) and \( V_{mp} \). These two values determine the maximum power point of the module which provides the greatest electrical power.

**Array power output**

The number of modules in one string and the number of strings in one array depend on the maximum possible input to the inverter. The numbers of modules in one string (connected in series) times the open circuit voltage of the module should not exceed the maximum input voltage of the inverter. The numbers of strings connected in parallel times the short circuit current should also not exceed the maximum input current of the inverter. In this simulation the SMA inverter SC500U with a maximum input of 600 V and 1600 is used. Combined with the Yingli Solar module, the array layout is 16 modules connected in series in one string and 194 strings connected in parallel for one array for a 50 MW reference plant.

The power output of the array (\( P_A \)) is the product of number of modules in string (\( M_{string} \)), maximum power point voltage (\( V_{mp} \)), strings in parallel (\( S_{parallel} \)) and short circuit current (\( I_{mp} \)):

\[ P_A = M_{string} V_{mp} S_{parallel} I_{mp} \] 4.42

**Temperature correction factor**

The power output is corrected by a temperature related factor taking into account efficiency losses due to heating of the modules. Therefore, the model calculates the hourly module and cell temperature as a function of solar radiation, ambient temperature (\( T_a \)) and wind speed (\( V_{wind} \)). The module back temperature (\( T_{Back} \)) is given by the following empirical relation:

\[ T_{Back} = I_e + b V_{wind} + T_a \] 4.43
Where, \( a, b \) = empirical (negative) coefficients determining the upper limit of module temperature and determining the rate of change of module temperature and \( I_{g,t} \) = the incident global irradiation on the module plane.

The cell temperature \( (T_c) \) is calculated as follows:

\[
T_c = T_{\text{Back}} + \frac{I_{g,t}}{I_0} dT
\]

Where, \( dT \) = the difference\(^37\) between module back temperature and cell temperature at STC and \( I_0 \) the irradiation at STC.

The temperature correction factor is calculated given the maximum power temperature coefficient of the module \( (\partial) \) and the module temperature at STC \( (T_o) \) by:

\[
F_{\text{TempCorr}} = 1 + \partial(T_c - T_o)
\]

### DC array output

To account for further losses which are not being addressed by modeling the module efficiency and temperature correction, pre-inverter derate factors are used. The losses are due to inaccurate maximum power point tracking (2%), due to diodes and connections (0.5%), dc-wiring (2%) and soiling of modules (5%). These numbers represent constant, average values taken from (SAM, 2011). Additionally a degradation derate factor of 0.942 is used to account for decreasing module performance due to aging.\(^38\) To get the array power output accounting for temperature correction and pre-inverter derate factors:

\[
P_{A,dc} = 0.8552 \, P_A \, F_{\text{TempCorr}}
\]

### 4.2.3 AC Output - Plant

#### Inverter model

To model the direct to alternating current (dc, ac) electricity conversion, the SANDIA performance model for grid-connected photovoltaic inverters is implemented into the simulation (King, 2007). The performance model allows simulating the inverter ac power output in dependence of the dc power

---

\(^37\) The change of cell temperature depends on the type of mounting and module structure: the value of 3 for \( dT \) represents glass, cell, polymer sheet structure mounted on an open rack according to (SAM, 2011).

\(^38\) This value represents the average value for loss of power output per year if the power output decreases linearly about 0.4% per year. The aging effect usually occurs and accelerates with time: to use a constant derate factor is a compromise to account for these losses and the usefulness of a “constant” energy yield over time which simplifies the economic calculations in chapter 5.
The parameters used are shown and briefly explained in Table 13.

<table>
<thead>
<tr>
<th>Parameter (Unit)</th>
<th>Description</th>
<th>Value</th>
<th>39</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{aco}$ (W)</td>
<td>Maximum ac power rating at nominal operating condition</td>
<td>506,000</td>
<td></td>
</tr>
<tr>
<td>$P_{dco}$ (W)</td>
<td>Corresponding dc-level to achieve $P_{aco}$</td>
<td>525,128</td>
<td></td>
</tr>
<tr>
<td>$P_{so}$ (W)</td>
<td>Dc power required to start inversion process</td>
<td>2,866.87</td>
<td></td>
</tr>
<tr>
<td>$P_{ac}$ (W)</td>
<td>Power of inverter consumed at night</td>
<td>79.3</td>
<td></td>
</tr>
<tr>
<td>$V_{dco}$ (V)</td>
<td>Dc voltage level at which the ac power rating is achieved at the reference</td>
<td>371.24</td>
<td></td>
</tr>
<tr>
<td></td>
<td>operating condition</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$C_0$ (1/V)</td>
<td>Parameter defining the curvature (parabolic) of the relationship between ac-</td>
<td>-5.11298E-08</td>
<td></td>
</tr>
<tr>
<td></td>
<td>power and dc-power at the reference operating condition</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$C_1$ (1/V)</td>
<td>Empirical coefficient allowing $P_{dco}$ to vary linearly with dc-voltage</td>
<td>1.58656E-05</td>
<td></td>
</tr>
<tr>
<td></td>
<td>input</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$C_2$ (1/V)</td>
<td>Empirical coefficient allowing $P_{so}$ to vary linearly with dc-voltage</td>
<td>0.000933119</td>
<td></td>
</tr>
<tr>
<td></td>
<td>input</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$C_3$ (1/V)</td>
<td>Empirical coefficient allowing $C_0$ to vary linearly with dc-voltage input</td>
<td>-0.00068396</td>
<td></td>
</tr>
<tr>
<td>$V_{dc,max}$ (V)</td>
<td>Maximum dc input voltage</td>
<td>600</td>
<td></td>
</tr>
<tr>
<td>$I_{dc,max}$ (A)</td>
<td>Maximum dc input current</td>
<td>1,600</td>
<td></td>
</tr>
<tr>
<td>$P_{dco}$ (W)</td>
<td>Maximum input power</td>
<td>525,128</td>
<td></td>
</tr>
</tbody>
</table>

Table 13: Inverter model parameters for SMA SC 500U
Source: own elaboration, data from [SAM, 2011]

To get the ac power the following empirically determined relationship has been used:

$$P_{A,ac} = \left( \frac{P_{aco}}{A-B} \right) \left( 1 + C(V_{dc} - V_{dco}) \right) (P_{A,dc} - B)^2 + C(P_{A,dc} - B)^2$$

Where,

$$A = P_{dco}(1 + C_1(V_{dc} - V_{dco}))$$

$$B = P_{so}(1 + C_2(V_{dc} - V_{dco}))$$

$$C = C_0(1 + C_3(V_{dc} - V_{dco}))$$

**Plant output**

To get the total power output a simplified method is used: The desired plant size (i.e. 50 MW) is divided by the cumulative nameplate capacity of all modules in the designed PV array (MW). The resulting factor is then multiplied with the array ac power output. Taking into account the post-

---

39 The inverter simulation allows for the use of different inverters. The required input parameters to the equations of the model have been determined by laboratory tests by SANDIA for different inverters. They have been extracted from the database of SAM which uses the same inverter model.
The optimum plant design would possibly use different inverter sizes for varying plant sizes minimizing inverter losses or avoiding energy losses due to failures in single inverters. However, the uniform approach for all plant sizes chosen in this work is regarded as sufficiently adequate.
5 Economic Model

5.1 Levelized Cost of Electricity

LCOE are a common tool to estimate the production costs of power plants. This method conveniently allows comparing the results for different types of generation technologies with a single figure. The LCOE approach is used as in (Breyer/Gerlach, 2009) where LCOE are calculated based on capital expenditures (or investment costs; Capex), annuity factor (crf), annual operation and maintenance expenditures (Opex) and annual net electricity generation (E_{net})\(^{41}\):

\[
LCOE = \frac{\text{Capex} \cdot crf + \text{Opex}}{E_{net}}
\]

5.1

The annuity factor (crf) is calculated given the weighted-average capital costs (WACC), the assumed plant lifetime (N) and annual insurance costs in percent of Capex (k_{ins}):

\[
crf = \frac{\text{WACC} (1 + \text{WACC})^N}{(1 + \text{WACC})^N - 1} + k_{ins}
\]

5.2

The weighted-average capital costs depend on the share of equity (E), share of debt (D), return on equity (k_E) and return of debt (k_D):

\[
\text{WACC} = \frac{E}{E + D} k_E + \frac{D}{E + D} k_D
\]

5.3

For CSP the total initial Capex in 2010 range between 2,566 - 9,728 EUR/kW depending on the SM. The values are derived based on the following specific costs: 1000 EUR/kW for the PB, 300 EUR/m² for the SF (related to aperture area of collectors) and 50 EUR/kWh\(_{th}\) for the TES (Trieb/Müller-Steinhagen/Kern, 2010). For PV initial Capex range between 2,400 - 2,920 EUR/kW based on specific costs of 1.8 EUR/W for modules and 0.6 EUR/W for inverters (Breyer/Gerlach, 2009). Tracking systems have additional costs of 0.24 EUR/W, 0.36 EUR/W and 0.52 EUR/W for 1-axis horizontal, 1-axis vertical and 2-axis tracking respectively (Siemer, 2009).

All other input variables are common values which are also used in similar studies. Capital costs are assumed to be moderate with 10% on equity and 6% on debt.\(^{42}\) Operational expenditures (Opex) are 1.5% of Capex for CSP and 0.35 - 0.73% of Capex for PV (depending on the tracking mode).

\[^{41}\] The net electricity generation is the result of the technical thesis model and varies for the different locations of the MSP according to irradiation, but also technology.

\[^{42}\] Between 2002 – 2011 commercial banks in Morocco offered loans with average interest rates of 6.35% (Al-Maghrib, 2010).
and loan term for CSP are 30, for PV 20 years. All required financial assumptions are summarized in Table 14.

<table>
<thead>
<tr>
<th>Initial Capex in 2010</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CSP</td>
</tr>
<tr>
<td>SM 1</td>
<td>2,566</td>
</tr>
<tr>
<td>SM 2</td>
<td>4,953</td>
</tr>
<tr>
<td>SM 3</td>
<td>7,341</td>
</tr>
<tr>
<td>SM 4</td>
<td>9,728</td>
</tr>
<tr>
<td>Total (EUR/kW)</td>
<td></td>
</tr>
<tr>
<td>Power Block (EUR/kW)</td>
<td>1000</td>
</tr>
<tr>
<td>Solar Field (EUR/m²)</td>
<td>300</td>
</tr>
<tr>
<td>Storage (EUR/kWhₘₜ)</td>
<td>50</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Opex (in % of Capex)</th>
<th>CSP</th>
<th>PV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1.5%</td>
<td>0.35%</td>
</tr>
<tr>
<td>Other financial assumptions</td>
<td>0.45%</td>
<td>0.55%</td>
</tr>
<tr>
<td>Share of Equity</td>
<td>30%</td>
<td></td>
</tr>
<tr>
<td>Share of Dept</td>
<td>70%</td>
<td></td>
</tr>
<tr>
<td>kₑ</td>
<td>10%</td>
<td></td>
</tr>
<tr>
<td>k₀</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>kₑₛ</td>
<td>1% of Capex</td>
<td></td>
</tr>
<tr>
<td>Plant lifetime</td>
<td>30 years</td>
<td>20 years</td>
</tr>
<tr>
<td>Market growth</td>
<td>50%</td>
<td>30%</td>
</tr>
<tr>
<td>Learning rates</td>
<td>PB: 5%, SF: 10%, TES: 10%</td>
<td>Module: 20%, Inverter: 10%, Tracking: 8%</td>
</tr>
</tbody>
</table>

Table 14: LCOE - financial assumptions
Source: own elaboration based on (Breyer/Gerlach, 2009; Trieb/Müller-Steinhagen/Kern, 2010; Siemer, 2009)

For the MSP not only the actual LCOE in 2010 are relevant, but also the cost development in the future. Costs usually decrease with experience and cumulative installed capacity. For each doubling of installed capacity, Capex decrease about a certain percentage (learning curve approach, see i.e. (Nemet, 2006)). To simulate the learning curve effect the cumulative installed capacity in 2020 must be estimated. Projections in various studies spread significantly ranging from 80 GW (IEA, 2008) to 1600 GW (Breyer, 2011) for PV and from 30 (Kearney, 2010) to 148 GW (IEA, 2010) for CSP.⁴³

Figure 12 shows all projections and the frequency distribution of applied growth rates.⁴⁴ The data indicates that the picture about the future market development is unclear, but that studies tend to assume higher growth rates for CSP (growth rates range between 11.1 - 96.7% for CSP and between 6.7 - 44.6% for PV). In the context of this study an annual, constant market growth of 30% for PV and 50% for CSP is assumed which results in a cumulative installed capacity in 2020 of 551 GW and 57.6 GW respectively.

⁴³ To keep the chart handy only the optimistic scenarios of each study are represented.
⁴⁴ Some studies assume different growth rates over time. Therefore, the frequency distribution consists of 50 values; ten for each study representing the years 2010 – 2020.)
Economic Model

Figure 12: Installed PV and CSP capacity (left) and frequency distribution of growth rates (right)

Source: own elaboration based on (IEA, 2008; EPIA, 2011; IEA, 2009; BSW, 2010; Breyer, 2011; Kearney, 2010; Greenpeace, 2009; IEA, 2010; Trieb/Müller-Steinhagen/Kern, 2010)

The reduction in investment costs over time can be calculated by the following set of formulas:

\[ \text{Capex}_x = \text{Capex}_0 \left( \frac{P_t}{P_0} \right)^{\frac{\log{\text{progress ratio}}}{\log{2}}} \]  \hspace{1cm} (5.4)

\[ P_x = \sum_{t=0}^{T} P_t \]  \hspace{1cm} (5.5)

\[ P_t = P_{t-1} (1 + GR_t) \]  \hspace{1cm} (5.6)

Where, \( \text{Capex}_x \) = capital expenditures at historically cumulated output level \( x \), \( \text{Capex}_0 \) = capital expenditures at initial output level in 2010, \( P_x \) = historically cumulated output level in \( x \), \( P_0 \) = initial output level\(^{45} \) and \( \text{progress ratio} = 1 - \text{learning rate} \), \( P_t \) = annual production of the specific year and \( GR_t \) = the growth rate of a specific year (\( GR_t \)).

For PV the phenomenon of progress has been analyzed in various publications and is well understood (Nemet, 2006; Breyer/Gerlach, 2009; EPIA, 2011). For the past decades the learning rate has been about 20% for PV modules. The learning rates for inverter and tracker production is usually estimated to be lower within the range of 5 - 10%. For CSP the effect of learning rate is less investigated due to little employment in the past. Studies typically assume a learning rate of 10% for SF and TES, but a lower rate for the PB (Trieb/Müller-Steinhagen/Kern, 2010).

Within the context of this study learning rates of 20%, 10% and 8% for PV-modules, inverters and tracking systems respectively, are assumed. For CSP - PB, SF and TES - 5%, 10% and 10% are assumed.

\(^{45}\) The initial output level equals the worldwide installed capacity in 2010 which is 40 GW for PV and 1 GW for CSP (see Breyer, 2011; Kearney, 2010).
The applied learning rates result in a progress ratio between 80% and 95%. The resulting decrease of Capex over time, are shown for all subclasses in Figure 13. Note that technologies with a large share of components with high learning rates achieve a greater reduction of Capex. The cost reduction potential reaches between 33% to 37% for CSP and 44% to 49% for PV until 2020 (for an overview of absolute Capex for all technologies from 2011 - 2020 see appendix . PV yields the greatest cost reductions due to the high module learning rate of 20%. CSP cost reduction potential is lower although higher growth rates for installed capacity have been assumed.

Figure 13: Decrease in Capex from 2010 to 2020 - PV (left), CSP (right)  
Source: own elaboration

LCOE are calculated for every solar plant (SM 1 - 4 and 1 - 4) installed between the years 2011 - 2020 for all sites of the MSP. The results are discussed in the next two chapters and can be found in detail in appendix H. Additionally, a sensitivity analysis is conducted in section 6.3.2.

5.2 Difference Costs

The DC approach is used to account for the advantage of CSP to deliver energy on demand. As demonstrated in section 2.2 production costs in Morocco are higher in evening hours. Therefore, it is economically preferable to run the CSP plants in evening hours instead of morning hours. The common LCOE approach only represents a method to calculate average, time-independent generating costs. In contrary, within the DC approach the value of the electricity produced by solar power plants is equivalent to the avoided production costs by the conventional energy system.

The complete production costs of the Moroccan electricity supply are given by indications from (Mouchtakiri, 2011), which estimate the average production prices per kWh in dependence of the national load level. Based on these indications and the hourly load values for 2010 an hourly set of production costs is derived (see section 2.2). These baseline values are displayed in Figure 14 for the whole year in 2010 and for January 1st of 2010.
The DC represent the difference between baseline values and LCOE of solar energy for a reference time period. For one hour the DC would be: the total amount of solar energy produced in that hour times the corresponding LCOE, minus the total amount of solar energy produced in that hour times the corresponding baseline value. In general the DC can be calculated for any time period.

1. **Annual DC**: The annual DC for a specific year and plant are calculated using the hourly (escalated\(^{46}\)) baseline values \(B_n\) EURct/kWh, the LCOE of the year of plant construction \(LCOE_k\) EURct/kWh depending on site and technology and the corresponding hourly and annual energy yield in kWh \(P_{h,n}\) and \(P_a\) respectively) from the technical model. The following formulas are used to calculate the total annual DC for a specific year (EUR) and the specific DC per unit energy for a certain year (EURct/kWh):

\[
DC_{total\ annual} = \frac{1}{100} \left( LCOE_k \ast P_a - \sum_{n=1}^{8760} P_{h,n} B_n \ast (1 + x_{fuel})^{-2010+p} \right) \tag{5.7}
\]

\[
DC_{specific\ annual} = (LCOE_k \ast P_a - \sum_{n=1}^{8760} P_{h,n} B_n \ast (1 + x_{fuel})^{-2010+p}) / P_a \tag{5.8}
\]

Where, \(k = \) year of plant construction\(^{47}\), \(p = \) specific year of annual DC to be calculated and \(x_{fuel} = \) escalation rate of conventional production costs (in %).

\(^{46}\) Production costs for conventional increase due to rising fossil fuel prices and inflation. Therefore, the baseline values are escalated by a constant rate per year. For all base scenarios a rate of 3% is assumed. This rate takes into account inflation and real fuel price increases. For comparison the average inflation rate in Morocco was 1.9%/a between 2000 – 2009 (Al-Maghrib, 2010).

\(^{47}\) It is assumed that each plant yields LCOE and avoided production costs according to the year of construction. For plants commissioned in 2012 the corresponding value in 2012 calculated in section 5.1 is assumed.
2. **DC for a 30-year period**: The average DC for a 30-year period indicate the overall economic performance of the solar plant compared to conventional generation during the whole plant lifetime. The formulas to calculate the total (EUR) and the specific lifetime DC (EURct/kWh) over 30 years are (all symbols as above):

\[
DC_{total, 30y} = \frac{1}{100} (LCOE \times 30P_{a} - \sum_{i=1}^{30} \left( \sum_{n=1}^{8760} P_{h,n} B_{n} \right) (1 + x_{fuel}^{-2010+k+i}) ) \\
DC_{specific, 30y} = (LCOE \times 30P_{a} - \sum_{i=1}^{30} \left( \sum_{n=1}^{8760} P_{h,n} B_{n} \right) (1 + x_{fuel}^{-2010+k+i}) ) / 30P_{a}
\]

Solar plants built in later years have lower DC for two reasons: on the one hand, production costs of conventional increase exponentially with time. On the other hand, LCOE decrease for plants being built in later years due to decreasing Capex over time (see section 5.1). Thus, the gap between conventional generation and solar energy costs becomes smaller.

A fictive result for lifetime DC for plants built in 2011 and 2012 could for example be as follows:

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSP</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>PV</td>
<td>4</td>
<td>3</td>
</tr>
<tr>
<td>LCOE (EURct/kWh):</td>
<td>14</td>
<td>13</td>
</tr>
</tbody>
</table>

The results would indicate that: Over a 30-year period solar energy from plants built in 2011 is in average only 3 - 4 EURct/kWh more expensive than conventional energy under a business-as-usual scenario. CSP yields lower economic costs than PV although LCOE are higher, because fossil fuel generation is avoided during high-priced time periods. Plants which are being built in 2012 have lower LCOE and DC than in 2011.

Of course, due to the simplified approach all results depend on the assumptions made. The most crucial are:

- Identical shape of the load curve for 30 years
- Production cost of 2010 indicated by (Mouchtakiri, 2011) and escalated by a constant rate per year
- Hourly power output of the technical model are based on the meteorological data of 2005 and are constant over time
- No impact of future renewable energy deployment or use of cheaper fossil fuel alternatives
- No discounting of future costs
Results for the DC of a 50 MW reference plant for all technologies in Ouarzazate are presented in the next chapter as well as the results of a sensitivity analysis. Additionally, based on the results for all sites, total DC of the MSP are calculated in chapter 8 for different scenarios.
6 Results for a 50 MW plant in Ouarzazate

6.1 Technical Performance

The model results give a good insight about plant characteristics for PV and CSP. To keep results handy only the performance indicators and the production patterns for 50 MW reference plants (CSP with dry cooling) in Ouarzazate are outlined in this chapter. The results for the same reference plants in all other sites of the MSP are summarized in appendix F and briefly discussed in chapter 7.

The performance indicators presented hereafter answer the question "What energy is produced and how?" - basically by providing aggregated figures. The production patterns answer the question "When is the energy produced?" by providing graphs and figures.

6.1.1 Indicators

The most important indicators are highlighted in the following text. However, further indicators can be found in Table 15 - Table 19.

<table>
<thead>
<tr>
<th>Technology</th>
<th>CSP</th>
<th>PV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SM 1</td>
<td>SM 2</td>
</tr>
<tr>
<td>Annual irradiation (kWh/m²/y)</td>
<td>2428</td>
<td>2369</td>
</tr>
<tr>
<td>higher irradiation yield in % of SM 1 / 1</td>
<td>-</td>
<td>100%</td>
</tr>
<tr>
<td>Annual net energy yield (GWh)</td>
<td>97.7</td>
<td>185.9</td>
</tr>
<tr>
<td>Annual gross energy yield (GWh)</td>
<td>106.6</td>
<td>204.9</td>
</tr>
<tr>
<td>higher electrical energy yield in % of SM 1 / 1</td>
<td>-</td>
<td>92.3%</td>
</tr>
<tr>
<td>Net Conversion factor</td>
<td>0.92</td>
<td>0.91</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>24.3%</td>
<td>46.8%</td>
</tr>
<tr>
<td>Irradiation to net electricity conversion</td>
<td>15.4%</td>
<td>14.7%</td>
</tr>
</tbody>
</table>

| Total full load hours | 2131 | 4099 | 6056 | 7102 | 1719 | 2055 | 2091 | 2280 |
| contribution solar field direct | 2131 | 2004 | 2806 | 3211 | - | - | - | - |
| contribution storage | 0 | 2095 | 3250 | 3881 | - | - | - | - |

Table 15: Common performance indicators - 50 MW, Ouarzazate
Source: own elaboration

The annual net energy yield for CSP in Ouarzazate varies depending on the SM between 97.7 GWh and 319.6 GWh. For PV it ranges between 86.0 GWh and 114.0 GWh depending on the tracking

48 For PV, the capacity refers to installed peak module capacity and for CSP to nameplate capacity of the turbine.
49 Definition: Net annual energy yield over firstly, the total annual irradiation received by the aperture area of collectors (CSP), or secondly, over the total cell area of modules (PV).
Results for a 50 MW plant in Ouarzazate

The corresponding capacity factors vary between 24.3% and 81.1% for CSP and 19.6% and 26.0% for PV. The irradiation to net electricity conversion is in general better for CSP than for PV. The highest values are reached by SM 1 (15.4%) and PV 1 (8.0%). The higher the SM for CSP, the lower is the conversion efficiency due to the more frequent use of storage and associated losses. For PV the conversion efficiency decreases with better tracking due to more irradiation on the module surface which leads to lower module efficiency.

All losses of the CSP-model have been theoretically described in section 4.1. The corresponding, actual values determined by running the model are summarized in Table 16.

### Table 16: Performance indicators - CSP only, 50 MW, Ouarzazate

<table>
<thead>
<tr>
<th></th>
<th>SM 1</th>
<th>SM 2</th>
<th>SM 3</th>
<th>SM 4</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Solar Field</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating hours of solar field (Irradiation &gt; 0)</td>
<td>4689</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overall geometrical loss coefficient of solar field</td>
<td>86.1%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual, average COS-loss</td>
<td>88.8%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual, average IAM-loss</td>
<td>96.9%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual, average Row-end loss coefficient</td>
<td>99.2%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overall optical loss coefficient</td>
<td>73.3%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average thermal loss coefficient</td>
<td>84.2%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solar Field reduction coefficient</td>
<td>98.5%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual average solar field efficiency</td>
<td>48.9%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Power Block</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power block operating hours</td>
<td>3171</td>
<td>4238</td>
<td>6157</td>
<td>7157</td>
</tr>
<tr>
<td>Average gross efficiency (weighted)</td>
<td>35.7%</td>
<td>36.4%</td>
<td>36.5%</td>
<td>36.5%</td>
</tr>
<tr>
<td>Average net efficiency (weighted)</td>
<td>33.01%</td>
<td>33.5%</td>
<td>33.2%</td>
<td>32.9%</td>
</tr>
<tr>
<td><strong>Parasitics (MW)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SF - HTF Pump</td>
<td>1.19</td>
<td>2.38</td>
<td>3.57</td>
<td>4.76</td>
</tr>
<tr>
<td>SF - Tracking</td>
<td>0.26</td>
<td>0.51</td>
<td>0.77</td>
<td>1.03</td>
</tr>
<tr>
<td>PB - Standy By</td>
<td>0.02</td>
<td>0.02</td>
<td>0.02</td>
<td>0.02</td>
</tr>
<tr>
<td>PB - Feedwaterpump</td>
<td>0.58</td>
<td>0.69</td>
<td>0.69</td>
<td>0.70</td>
</tr>
<tr>
<td>PB - Ventilation</td>
<td>0.92</td>
<td>1.65</td>
<td>1.66</td>
<td>1.67</td>
</tr>
<tr>
<td>Total Parasitics</td>
<td>2.04</td>
<td>3.60</td>
<td>5.05</td>
<td>6.50</td>
</tr>
</tbody>
</table>

In Ouarzazate the geometrical, optical, thermal and field efficiencies are 86.1%, 73.3%, 84.2% and 98.5% respectively. They account for the overall annual SF efficiency of 48.9% (irradiation weighted). The average gross PB efficiency ranges from 35.7% to 36.5%. The SM 1 plant has the lowest average

---

50 Efficiencies refer to irradiation weighted, average values which have been calculated for operating hours of the solar field (efficiency values during hours with high irradiation have higher weight).

51 Coefficient relates total annual thermal losses to total annual normal direct irradiation on total aperture area of collectors.
Results for a 50 MW plant in Ouarzazate

gross PB efficiency as it operates most of the time in part load. The average parasitic load ranges from 2 MW to 6.5 MW (4% - 13% of nominal plant capacity) depending on the field size. For higher SM more collectors need to be tracked and more cooling water and HTF must be pumped due to longer plant operation.

The PV module parameters relevant in the model are especially the COS-loss coefficient achieved for the different tracking modes (72.9% - 100%), the PV module efficiency (14.1% - 13.9%), the temperature correction coefficient (~99.9%), the inverter efficiency (97.1% - 97.4%) and the pre- and post-inverter derate factors (85.5%, aggregated). Interestingly, the average values for most parameters differ insignificantly between the different technologies Table 17. Even temperature correction and lower module efficiency due to better tracking account for low differences among the assessed technologies. Thus, only the tracking method and the associated COS-loss coefficient vary significantly. However, note that maximum and minimum values for single hours can differ significantly from the average value for all parameters. Part load inverter efficiency can for example be as low as ~75%, the temperature correction factor may go down to ~98% and module efficiency commonly varies between 13.5% and 16% depending on the operating conditions.

<table>
<thead>
<tr>
<th></th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Average COS-loss coefficient</strong></td>
<td>72.9%</td>
<td>88.8%</td>
<td>91.1%</td>
<td>100.0%</td>
</tr>
<tr>
<td><strong>Average module efficiency</strong></td>
<td>14.1%</td>
<td>14.1%</td>
<td>14.0%</td>
<td>13.9%</td>
</tr>
<tr>
<td><strong>Average temperature correction factor</strong></td>
<td>99.9%</td>
<td>99.9%</td>
<td>99.9%</td>
<td>99.9%</td>
</tr>
<tr>
<td><strong>Average inverter efficiency</strong></td>
<td>97.3%</td>
<td>97.4%</td>
<td>97.2%</td>
<td>97.1%</td>
</tr>
<tr>
<td><strong>Pre-inverter derate</strong></td>
<td>85.5%</td>
<td>98.0%</td>
<td>99.5%</td>
<td>98.0%</td>
</tr>
<tr>
<td><strong>Mismatch (MPP)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Diodes &amp; Connections</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>DC Wiring</strong></td>
<td>95.0%</td>
<td>94.2%</td>
<td>99.0%</td>
<td>99.0%</td>
</tr>
<tr>
<td><strong>Soiling</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Degradation</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Post-Inverter Derate</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>AC-Wiring</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 17: Performance indicators - PV only, 50 MW, Ouarzazate
Source: own elaboration

6.1.2 Patterns of Energy Production

**CSP**

For the CSP-model the SM is most decisive to achieve high full load hours of plant operation. For SM 1 full load operation is only achieved during summer time when irradiation reaches design point level.\(^2\) In contrary, in winter the plant only reaches a power output half the nominal capacity. With

\(^2\) Some energy needs to be wasted in summer month when irradiation is above the design point (800 W/m\(^2\)). Choosing the best design point is basically an economic optimization depending on the costs for the SF and local irradiation.
Results for a 50 MW plant in Ouarzazate

higher SM, the TES is used to run on full load if possible. Especially in summer number of full load hours and contribution from TES is high.

![Figure 15: Hourly charge and discharge of TES for CSP SM 2-4](source: own elaboration)

The use of TES reflects the annual distribution of available irradiation. The TES has a higher activity (charge and discharge) in summer month. The maximum storage capacity of 6h (SM 2), 12h (SM 3) and 18h (SM 4) is only achieved in summer month for SM 3 and 4. SM 2 operates almost all year round up to the maximum storage capacity (see Figure 15).

![Figure 16: Duration curve and hourly cumulated dispatch of energy, CSP, 50 MW, one year](source: own elaboration)

To get an idea about when the energy is produced the duration curves of all CSP-plants are depicted in Figure 15Figure 16 (left). It shows that SM 1 plants operate more frequently on part load than higher SM. Interestingly, SM 4 only produces less energy per storage capacity than SM 2 and SM 3
indicating that the TES is over-dimensioned. Additionally, Figure 16, right shows the cumulated output during the year for each hour of the day. For SM 1 production hours occur only when the sun is shining. For all other SM most of the production is dispatched order in evening hours (for the dispatch order see section 4.1.3). Figure 17 compares the production during a typical summer and winter day. In winter only few operating hours and full load hours are achieved compared to a day in summer. During the summer day SM 4 is able to operate throughout day and night. SM 3 and SM 2 can produce energy for up to 22 and 18 hours respectively. The SM 1 plant reaches full load approximately between 10 - 16 a.m. when irradiation is above the design point. Note also that during sunshine hours the power output of SM 4 is the lowest due to the high parasitic load.

PV

For the different PV plants power output patterns are more similar. For north-south 1-axis horizontal tracking energy yields are higher towards the summer and lower towards winter. All other tracking systems and fixed tilted systems show similar patterns all over the year. The duration curve shows clearly that power output is always well below installed module capacity and only during around 4200 hours per year the PV systems produces energy. The cumulated energy per year and hour shows that power output is high during mid-day hours (see Figure 18).
The daily power production depends heavily on daily irradiation and season. During a typical winter day production starts later in the day and ends earlier than in summer. The differences in energy yield between the tracking systems and fixed tilted systems are higher during summer days when the cos-losses are higher due to the wider sun path. For comparison of a typical winter and summer day see Figure 19.

![Figure 19: Daily PV net power for a winter (left) and summer (right) day](source: own elaboration)

### 6.2 Model Validation

To validate the applied model the power output of all technologies is compared with the results for identical plants in the same location generated by the System Advisory Model (SAM). SAM is software provided for free by the National Renewable Energy Laboratory in the U.S. (NREL). SAM is able to model different RE systems including wind energy systems, concentrated solar thermal and photovoltaic applications. For more information or download of the program see (NREL, 2011). For a very detailed description of the program see (SAM, 2011).

The validation is based on direct comparison of the annual and hourly power output calculated by SAM and the thesis model for the common location El Paso, Mexico. The location is saved in the SAM library. Some of the relevant site characteristics in El Paso are depicted in Table 18.

<table>
<thead>
<tr>
<th>Location</th>
<th>El Paso, USA, Texas latitude: 35.13°, longitude: -116.67°</th>
</tr>
</thead>
<tbody>
<tr>
<td>Elevation</td>
<td>1186m</td>
</tr>
<tr>
<td>DNI, GHI</td>
<td>2429.8 kWh/m², 2064.8 kWh/m²</td>
</tr>
<tr>
<td>Name or location of SAM weather file</td>
<td>El paso texas.csv</td>
</tr>
</tbody>
</table>

Table 18: Characteristics of the location in SAM used for validation  
Source: own elaboration based on (SAM, 2011)

53 The reason that validation has not been done based on a site of the MSP is that data is more easily transferable from SAM to the thesis model than vice versa.
6.2.1 CSP

For CSP the SAM system “CSP-trouch-physical” is elected. All calculations are processed with most of the default properties suggested by SAM. Only the following inputs have been changed and set to the values used in the thesis model:

- Field aperture area
- Thermodynamic efficiency and type of cooling
- Design gross output and irradiation at design point

The thesis model results show a sufficient consistency with SAM-results for the scope of this work (see Figure 20). The annual gross energy yields of the thesis model deviate from SAM-results in the order of +6.3% to -0.51%. More significant deviations occur especially for SM 3 and SM 4 which indicates that there are differences in the modeling of the TES (higher losses in SAM). With maximum deviations of +3.6% (SM 3) and +2.7% (SM 4) the results for the net power output match better compared to the figures of the gross power output.

![Figure 20: Difference between thesis and SAM results - annual energy yield CSP](Source: own elaboration)

In order to validate the hourly production only the results of SM 1 are compared between both simulation tools. The hourly production shows average absolute deviations from SAM results in the order of +2.65 MW (gross power) and +3.22 MW (net power) representing +5.3% and +6.44% of the nominal capacity of the power plant respectively. The frequency distribution of absolute deviations of hourly power output is depicted in Figure 21. It shows that the absolute deviation is higher than 10% of the nominal capacity in 2027 hours per year and higher than 20% in 524 hours given total PB operating hours of 3131. Significant deviations are partly due to the earlier start of power production in the thesis model which does not account for a start-up phase of the power plant as SAM. The plot

---

54 For higher SM the dispatch order of the thesis model allocates energy production in evening hours. It was not possible to adjust the dispatch in SAM accordingly so that differences in the dispatch do not dominate possible errors. Therefore, only CSP without storage is validated on an hourly basis.
of the net power output for four characteristic days, show that the power plant output of the thesis model may be due to different parasitic loads assumed (see Figure 21, right). However, the correlation coefficients between both simulation results are high with 0.943 and 0.945 for the hourly net and gross power output respectively.

6.2.2 PV

For the PV-model the “component-based model” of SAM is used to create a validation reference. SAM also uses the SANDIA module and inverter model. Therefore, the same module and inverter is elected for modeling\(^ {55}\). Additionally, string and array arrangement and derate factors are as in the thesis model and the Hay-Davies radiation model is used for the calculation of the irradiation on a tilted surface.

The PV thesis model results show better consistency with SAM (all validation indicators are displayed in Table 19). The net power output deviates about 1.35%, 1.47%, 1.65% and 1.38% from the results in SAM (for 1, 2, 3 and 4 respectively). For the PV system the hourly deviation could easily be compared: the average absolute hourly error ranges from +1.07 MW to +1.33 MW representing an average relative error in the order of +2.13% and +2.66% of nominal plant output.

<table>
<thead>
<tr>
<th>Indicator(^ {56})</th>
<th>Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Deviation annual energy</td>
<td>1.35%</td>
</tr>
<tr>
<td>Average absolute error per hour (MW)</td>
<td>1.10</td>
</tr>
<tr>
<td>Average relative error per hour</td>
<td>2.19%</td>
</tr>
<tr>
<td>Correlation coefficient (SAM/Theesis)</td>
<td>0.9969</td>
</tr>
</tbody>
</table>

Table 19: Validation indicators for the PV thesis model

Source: own elaboration


\(^{56}\) Deviation of thesis model results from SAM results. Average relative error refers to absolute error related to nominal plant capacity.
The correlation coefficient between the two net power output time series is in all cases above 0.995. Thus, the developed PV-model shows sufficient accuracy for the purpose of this master thesis.

The frequency distribution of errors and the daily net power output for four days for a fixed tilted system show the consistency of the thesis model compared to SAM (see Figure 22). Only in 81 hours of the year the error is greater than 10%, in 225 hours greater than 5% and in 1499 hours greater than 2% given 3831 operating hours in total.

![Figure 22: Frequency distribution of errors and net power output for four days for PV 1.](Source: own elaboration)

### 6.3 Economic Performance

The ideas behind the economic model have been described in chapter 5. The summary of the results of the economic analysis presented hereafter can be done very briefly: Only the calculated LCOE and DC are displayed. The results can deliver a first answer on how costly solar energy in Morocco will be. Of great importance is the sensitivity analysis conducted thereafter analyzing the variation of results if financial and economic assumptions are changed.

#### 6.3.1 LCOE and DC

For the 50 MW reference plant in Ouarzazate the LCOE are ranging depending on the SM between 12.8 - 14.6 EURct/kWh in 2012. They decline to 9.6 - 10.3 EURct/kWh for plants built in 2020. PV achieves lower LCOE ranging depending on the tracking mode between 10.3 - 9.6 EURct/kWh in 2012 and 5.4 - 5.7 EURct/kWh in 2020. An overview of LCOE for all technologies up to 2020 provides Figure 23 (left). The cheapest technology in terms of LCOE is SM 3 for CSP and 1-axis horizontal tracking for PV. However, SM 1 - 2 achieve almost identical LCOE which also accounts for all PV tracking modes. Only CSP with SM 4 and fixed tilted PV systems (the latter in early years only) are more expensive in terms of LCOE (approximately +1.8 EURct/kWh and +0.7 EURct/kWh in 2012 compared to the cheapest alternatives).
Taking into account the dispatch ability of CSP and the avoided production costs of conventional energy (see section 5.2), economics of CSP improve compared to PV - at least in the first years. However, PV still achieves lower DC and due to the fast learning rate for PV-modules the gap in DC between PV and CSP increases with time. In general the values for the average 30-years DC are surprisingly low or even negative for both technologies. The lifetime DC range between 1.3 - 3.2 EURct/kWh for CSP-plants built in 2012 and -2 - -3.5 EURct/kWh in 2020. For PV they are even lower between 0 - -0.6 EURct/kWh in 2012 and between -7.3 - -7.7 EURct/kWh in 2020. Negative values indicate that the electricity in average is cheaper than generation by the conventional system under the assumptions outlined in section 5.2.

6.3.2 Sensitivity Analysis

LCOE

The LCOE heavily depend on the economic and financial assumptions made. In the following sensitivity analysis several assumptions are changed compared to the base scenario. The impact on LCOE is analyzed for the case that:

- The initial Capex increase or decrease about 10% (equally in all subclasses of Capex)
- The interest rate on equity and depth is changed to:
  - A “cheap-money-scenario” with 5% and 8% respectively
  - An “expensive-money-scenario” with 8% and 12% respectively
  - An “soft-loan-scenario” with 3% and 5% respectively\(^{57}\)
- The loan term is 20 instead of 30 years
- OPEX increase or decrease about 10%

\(^{57}\) In the soft loan scenario it is assumed that loans from international institutions and donors are provided as equity (i.e. World Bank). The debt is assumed to be financed by the Moroccan Government or cheap commercial loans.
Of course, also technical improvements influence the LCOE due to an increase of power output. However, the variability of the result to technical parameters is often of minor importance compared to economic aspects and is therefore not considered in this work.

The variability for the cheapest alternative of PV and CSP (in terms of percent of LCOE, base scenario) ranges from approximately 12% to 17% for the “expensive”, -19% to -27% for the “soft loan” scenario, to only -1% to -11% for the change of Opex about 10% depending on technology and year. The change in Capex or loan term also has a significant impact on LCOE (see Figure 24). Some parameters have a stronger or a weaker impact on LCOE in later years (i.e. change in Opex: -1.3% in 2012 and -5.2% in LCOE in 2020 for PV).

![Figure 24: Sensitivity of LCOE for SM 3 (yellow) and PV 2 (blue) - 2012 - 2020](source: own elaboration)

DC

Also the DC depend on the assumptions made. Especially changes in escalation of production costs, LCOE, baseline values or residual load influence the results. In the further analysis the baseline values indicated by (Mouchtakiri, 2011) and the LCOE are not varied58; however, the following two factors are analyzed more deeply:

- **Change of residual load**: The economic advantage of PV over CSP can be expressed by the difference between the DC of PV and CSP: If the result is positive, PV is cheaper; if it is positive CSP is cheaper. This difference has been calculated as indicator for 2 additional scenarios in which 1000 MW capacity of CSP (scenario A) or PV (scenario B) is already installed in Morocco. Scenario A results in a lower residual load in evening hours and scenario B in a lower mid-day peak. It is assumed that under these conditions a new 50 MW plant should be built.

**Results**: PV is still cheaper even if the residual load changes in both scenarios. However, Figure 25 shows that the difference in DC for scenario B is about 1.5 EURct/kWh less than in

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58 This is done for the MSP-scenario analysis for the total DC in chapter 8.
scenario A (see Figure 25). This is due to the low value of additional PV power and the higher value of CSP. The contrary is valid for the high CSP-penetration scenario.

![Figure 25: Difference in DC (PV and CSP, left) for different residual loads (right) Source: own elaboration](image)

- **Different escalation of production costs**: The effect of different cost escalation is analyzed for a specific example in which the DC per kWh electricity are calculated for a PV plant built in 2015 operating until 2045 (fixed tilted, 50 MW).

**Results**: It is clearly visible that the plant becomes more competitive given higher escalation rates (see Figure 26): For 3.5% the break-even (DC per kWh equal zero) is already in 2028, for 3.0% in 2031 and for 2.5% in 2034. The plant runs economically from a whole lifetime perspective if the sum of all annual DC is <0. For the assumed PV plant for example this is true for an escalation of production costs of approximately 2.95%.

![Figure 26: DC for a PV 1, 50 MW, built in 2015 given different escalation of production costs Source: own elaboration](image)

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59 So far discounting DC costs is neglected, but the net present values for the complete MSP scenarios are calculated in chapter 8.
7 Comparison of Sites and Technologies

To get an overview about site-specific differences within the MSP the same results as in chapter 6 are calculated for all sites. To keep things simple, only the main indicators of technical and economic performance are compared between the five sites. It is important to note that the results for the different sites depend on the irradiation in the year 2005. The data might represent a better year for one site than for another. For example in Ouarzazate DNI was approximately 10% above and in Boujdour about 11% below the long-term average (see 3.3). Thus, results are not decisive in finally judging about the best site. However, they give a good overview of how the results change if the level of irradiation changes. Additionally, the results are used for the scenario development in chapter 8.

7.1 Performance Evaluation

7.1.1 Energy Yield

Ouarzazate is the most productive site followed by Boujdour and Laayoune which almost have identical energy yields for all technologies. Ain Ben Mathar has lower energy yields for CSP due to the lower share of DNI, but in contrary reaches higher yields for PV. The only site with significantly lower production for all technologies is Tarfaya: For CSP it is 25% to 11% less than Ouarzazate and for PV 7% to 10% less. Interestingly, Boujdour and Laayoune yield around 3% more energy for SM 4 than Ouarzazate: The explanation is a more evenly distributed irradiation around the year leading to less excess energy which cannot be stored (see Figure 27).

![Figure 27: Energy yield of all sites compared to results in Ouarzazate, 50 MW](Image)

In general it is to be noted that the site quality is relative and does not only depend on the absolute annual values, but distribution of irradiation, ratio of DNI and GHI and can vary according to the
technology used (i.e. for Boujdour for PV 2 energy yield is only 1% lower than in Ouarzazate, but for PV 3 it is 5% lower).

7.1.2 LCOE and DC

This section gives a first idea of the costs in different sites. It is to be noticed that almost the same patterns occur in all sites. The following points can be underlined (see also Figure 28 and Figure 29 for a graphical presentation of costs):

1. The biggest advantages of PV - high learning rate and lower Capex - render PV the cheapest alternative both in LCOE and (lifetime) DC in all years from 2012 - 2020:
   - PV has minimum LCOE and DC of 9.6 EURct/kWh and 0.4 EURct/kWh respectively in 2012 and 5.4 EURct/kWh and -7.7 EURct/kWh in 2020
   - CSP has minimum LCOE and DC of 12.8 EURct/kWh and 1.3 EURct/kWh respectively in 2012 and 9.2 EURct/kWh and -3.5 EURct/kWh

2. The maximum bandwidth of costs for all site is decreasing over time and relatively low despite different site conditions:
   - For LCOE it is: 2.27 - 1.64 EURct/kWh (CSP) and 1.55 - 0.90 EURct/kWh (PV)
   - For DC it is: 1.75 - 1.26 EURct/kWh (CSP) and 1.43 - 0.82 EURct/kWh (PV)

3. The cheapest technologies in terms of LCOE are SM 3 and 1-axis horizontal tracking. In terms of DC SM 2 clearly is the cheapest solution for CSP and 1-axis horizontal or 2-axis tracking for PV are about the same. Ouarzazate, Boujdour and Laayoune only show insignificant costs differences between these cheapest technologies (1% - 2%). Ain Ben Mathar is only significantly more expensive in CSP (+~8%). Tarfaya has the highest costs with +12% to +14% for PV and CSP respectively (see Figure 29).  

# Footnote
60 Note, that the annual irradiation in Tarfaya which is used for the calculations is approximately 10% lower than the long-term average for the same site (see section 3.3).
For a complete overview over all calculated LCOE and DC for all sites and years view appendix H.

### 7.2 System Compatibility

PV has the advantage of low LCOE and DC, for CSP the advantages are dispatch ability of power and the good capability to contribute to ancillary services of the national electricity grid. The disadvantages are complementary: High costs for CSP and weaker system compatibility of PV.

From a utility perspective power plants have to suit well to the rest of the energy system, should be able to contribute to grid stability (provision of reserve power, frequency and voltage control, black start capability) and to provide firm capacity.

<table>
<thead>
<tr>
<th>CSP</th>
<th>PV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispatchable power</td>
<td>Lower LCOE</td>
</tr>
<tr>
<td>Cheap storage option</td>
<td>Lower DC</td>
</tr>
<tr>
<td>Ancillary services</td>
<td>Ancillary services:</td>
</tr>
<tr>
<td>- Active power control</td>
<td>+ Reactive power provision</td>
</tr>
<tr>
<td>- Reactive power control</td>
<td>+ Negative reserve power</td>
</tr>
<tr>
<td>- Negative and positive reserve power</td>
<td>Less technical expertise for O&amp;M required</td>
</tr>
<tr>
<td>Higher local manufacturing potential</td>
<td>Up to ~30% less land use per unit energy</td>
</tr>
<tr>
<td>+</td>
<td>-</td>
</tr>
<tr>
<td>Higher LCOE</td>
<td>No coverage of evening peak</td>
</tr>
<tr>
<td>More technical expertise for O&amp;M required</td>
<td>Only expensive battery storage</td>
</tr>
<tr>
<td>More land required</td>
<td>Intermittency of power supply</td>
</tr>
<tr>
<td></td>
<td>Positive reserve power is possible but requires curtailing CO₂-free energy</td>
</tr>
</tbody>
</table>

Table 20: Benefits and drawbacks of CSP and PV
Source: own elaboration

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61 Especially for mirror production, mounting and site preparation, see (Young/ISI, 2011).
62 SAM calculated a corresponding land use of approximately 1,278,820 m² and 886,074 m² for CSP SM 1 and PV 2 energy yields of 101.7 GWh and 106.4 GWh respectively. These figures result in 12.6 m²/MWh for CSP and 8.3 m²/MWh for PV which is 33.4% less.
During the field research two especially crucial issues for the integration of solar energy in Morocco have been highlighted. Firstly, solar energy should contribute to coverage of the characteristic evening peak in the Moroccan load and secondly, intermittency should be minimal. Both aspects are imposing a challenge on the employment of large, utility-scale PV-plants. From a long-term perspective contribution to frequency control might also play an important role.

To get a better understanding of the role of grid compatibility of PV and CSP, three topics are discussed in the following sections: active and reactive power supply, intermittency and ability for peak coverage of PV and CSP. For an introducing overview of general benefits and drawbacks of both technologies see Table 20.

7.2.1 Active and Reactive Power Control

Active Power Control

In electricity grids consumption and production of electricity need to be equal at all times to keep the operating grid frequency of 50 Hz. If frequency drops below this value, more power is required to stabilize the grid. In the case of a higher frequency less power is required. This addition or drop in power must be available within seconds or up to 30min depending on the type of reserve activated (primary, secondary and tertiary frequency control). This service is usually provided by fast-ramping conventional power plants (hydro or gas turbines). However, with increasing penetration of solar energy in Morocco the capability of providing these services from CSP and PV is a benefit.

In the case of PV, provision of negative reserve power (decreasing power output) is uncomplicated: Available functions include reducing the inverter power according to the grid frequency or on demand of the TSO. However, it is more difficult to increase power output if positive reserve power is needed. To do so, the power plant needs to run on part-load during normal operation which is uneconomic without compensating incentives and curtails CO₂-free electricity.

In the case of CSP positive and negative reserve power can be delivered on demand. The used turbines can usually provide power above nominal load or power output can be curtailed in normal operation mode and increased on demand. Varying the power supply is possible in the order of ramp rates of approximately 4% of nominal power per minute within a range of 30-100 % of nominal power (Trieb, 2011). Primary frequency control (automated power provision by droop control) can also be provided. The storage allows to store the thermal energy, thus no CO₂-free electricity is wasted even if reserve power is required at night.
Reactive Power Control

Reactive power control is needed to stabilize the grid voltage which is necessary for smooth operation. It additionally can influence the amount of transportation losses in the grid. Modern PV inverters can set the power factor ($\cos(\phi)$) of the inverter to a specific value. All inverters of a PV plant can be adjusted so that the power factor required at the feed-in point is achieved. With additional communication solutions the power factor can also be pre-set to vary throughout the day or as a function of voltage at the feed-in point. This ensures a contribution to reactive power provision for the system (SMA, 2009). Studies show that reactive power provision by PV inverters can be achieved on an economic base (Braun, 2007). Thus, PV plants can contribute to reactive power provision with already existing technology.

CSP plants are using synchronous generators which can provide reactive power just as normal conventional power plants. One can argue that experience here is vast and voltage control is thus, easier to handle than with PV plants.

7.2.2 Intermittency of PV

One of the main obstacles to employ PV instead of CSP is the intermittent power supply of large PV plants and resulting voltage instabilities of the grid, especially in Morocco (Amrane, 2011). Fluctuations of power supply can be caused due to varying irradiation intensity (i.e. by clouds and shading of modules) and may lead to significant sudden drops in power output. In general variability may occur in different timescales either causing problems in power quality (voltage flicker; within seconds) or requiring regulation reserves (minutes), load following (minutes to hours) or different scheduling of plants (hours to days). Also the spatial dimension is important. Power quality problems may already occur in areas much smaller than the responsible balancing areas (NREL, 2009).

A frequency distribution of hourly power gradients from the thesis model for a 50 MW PV reference plant in Ouarzazate is displayed in Figure 30. It shows that most power gradients are in the order of 5 - 10% of nominal load. Very drastic changes in power (>30%) occur very seldom. Hourly up to daily intermittency can be balanced by adjusted scheduling of all available power plants if the expected power output can be forecasted which involves additional costs. Distributed generation of PV can additionally smooth the variability of the power output (NREL, 2009). However, studies analyzing dispersed plants (~280 km) indicate that site diversity does not limit intermittency sufficiently to dismiss the need for dispatch able demand response (Curtright/Apt, 2007).
Short-term intermittency within minutes and seconds is more difficult to handle. Passing clouds can reduce peak insolation up to 60% within seconds and power output may also drop in a similar range depending on the plant characteristics (NREL, 2009). Unfortunately, power gradients for small temporal step sizes could not be analyzed in this work as the solar data is only available in hourly resolution. However, research on this topic is important and should be envisaged in further studies for Morocco.

Despite the intermittency it can be reasonable for Morocco to take advantage of low LCOE for PV. Plants can be implemented in small to medium scale size (up to several MW) within a distributed generation approach reducing the impact of intermittency of single plants and avoiding major grid instabilities. Another approach suggested by (Uh, 2012) is to combine regional hydro- and PV power to deliver stable power supply. Research is underway to investigate this option.

All in all the impact of intermittency of large-scale PV plants on the Moroccan grid is unclear. However, intermittency does not need to be an integration barrier as fast ramping conventional could generally provide balancing power (Curtright/Apt, 2007). Feasibility of very large scale-PV (>50 MW) has also been demonstrated all over the world. However, viability especially under Moroccan grid conditions needs to be investigated together with the Moroccan TSO.

### 7.2.3 Peak Coverage

CSP plants can deliver power on demand. If a TES is used, CSP plants are able to cover the evening peak of the Moroccan daily load profile. Every MW of capacity from solar energy contributing to cover the peak does not need to be invested in new conventional generation capacity. If the electricity demand continues to grow as before Morocco needs up to 6,000 MW of firm capacity until
2020.\textsuperscript{63} This will be costly. PV without storage capacity cannot contribute to cover the evening peak. In this case more conventional capacity needs to be added than in the case of CSP utilization. One solution is to use battery storage for PV although it is not commonly employed in existing PV farms and likely to make PV more expensive than CSP.

All in all, the lack of ability to cover evening peaks is the most important disadvantage of PV. This may render PV the second best option for system planning despite lower LCOE. Therefore, in the scenario analysis different shares of PV and CSP penetration are assumed.

\textsuperscript{63} A growth rate of electricity consumption of 7\% p.a. and a security margin of 25\% of the annual peak load is assumed.
8 Scenarios Analysis for the MSP

8.1 Scenarios and Performance Indicators

The economic analysis renders PV as the best technology option. The system related arguments speak for CSP. To simulate the impact of different PV and CSP utilization four scenarios are analyzed in this chapter.

<table>
<thead>
<tr>
<th>Site</th>
<th>Installed capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ouarzazate</td>
<td>150</td>
</tr>
<tr>
<td>Ain Ben Mathar</td>
<td>100</td>
</tr>
<tr>
<td>Boujdour</td>
<td>125</td>
</tr>
<tr>
<td>Tarfaya</td>
<td>150</td>
</tr>
<tr>
<td>Laayoune</td>
<td>150</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Site</th>
<th>Technology Choice for the Scenarios A, B, C, D (yellow = CSP SM 2, blue = PV 2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ouarzazate</td>
<td>A B C D</td>
</tr>
<tr>
<td>Ain Ben Mathar</td>
<td>A B C D</td>
</tr>
<tr>
<td>Boujdour</td>
<td>A B C D</td>
</tr>
<tr>
<td>Tarfaya</td>
<td>A B C D</td>
</tr>
<tr>
<td>Laayoune</td>
<td>A B C D</td>
</tr>
</tbody>
</table>

Table 21: Assumed schedule for commissioning of solar plants within the MSP

Source: own elaboration and assumptions based on indications by (Amrane, 2011)

Scenario A): Strict use of the cheapest technology in terms of DC is assumed which results in 150 MW CSP\(^{64}\) and 1850 MW PV until 2020.

Scenario B): Shares of roughly one third CSP and two thirds of PV are realized resulting in 1325 MW PV and 675 MW CSP.

Scenario C): Here, two thirds CSP and one third PV are employed: 750 MW and 1250 MW respectively.

Scenario D): Only plants generally being able to cover the evening peak are used: 2000 MW CSP.

\(^{64}\) The decision for the first stage of approximately 150 MW in Ouarzazate is already been made in favor of CSP. Construction will start in 2012.
For PV only continuous horizontal 1-axis and for CSP only SM 2 is used as they are the cheapest options in terms of DC according to the economic analysis in chapter 5 and 6.

The commissioning of plants is following the same schedule in all scenarios. Years and stages for commissioning in each site have been discussed with the project developers at MASEN and are displayed in Table 21 (Amrane, 2011). For each site of the MSP (except Ain Ben Mathar) there are three stages of development with single project sizes varying from 100 - 200 MW. Usually, CSP plants are constructed within two and PV plants within one year. Therefore, for plants to be commissioned for example in 2016, LCOE of the year 2015 and 2014 for PV and CSP respectively are be assumed.  

All scenarios are analyzed on the base of different performance indicators (see Table 22). The values for all indicators summarize the impact of each scenario in respect to electricity costs, energy yield, capital requirement, peak shaving ability and environmental benefits.

<table>
<thead>
<tr>
<th>Concern</th>
<th>Indicator</th>
<th>Description</th>
<th>Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity costs</td>
<td>Total LCOE</td>
<td>The sum of LCOE which occur for all solar plants for 30 years after commissioning.</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>LCOE/kWh</td>
<td>The average LCOE which occur for all solar plants for 30 years after commissioning weighted with the energy yield of each plant.</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Total DC</td>
<td>The sum of DC which occur for all solar plants for 30 years after commissioning. Fuel cost escalation: 3%.</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>DC/kWh</td>
<td>The average DC occurring for all solar plants for 30 years after commissioning weighted with the energy yield of each plant.</td>
<td>4</td>
</tr>
<tr>
<td>Energy Yield</td>
<td>Annual</td>
<td>Annual energy yield of all plants for a year in which all are operating (after 2020 until 2044).</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>%</td>
<td>Energy yield in % of the consumption in 2020 assuming an increasing electricity demand of 7% p.a.</td>
<td>6</td>
</tr>
<tr>
<td>Capital requirement</td>
<td>Total investment</td>
<td>For all plants occurring until the last plant is built (2020).</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>Investment/kW</td>
<td>Average investment per installed capacity for all plants (weighted with plant size).</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>Investment/kWh</td>
<td>Average investment per unit energy produced during a plant lifetime for all plants (weighted plant energy yield).</td>
<td>9</td>
</tr>
<tr>
<td>Peak shaving</td>
<td>Conventional</td>
<td>The remaining need for conventional plant capacity in 2020 assuming 7% growth of annual maximum peak load p.a. and adding a 25% security margin on top.</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>“Firm” capacity</td>
<td>The installed capacity which is able to deliver energy during the evening peak between 7-12 p.m.</td>
<td>11</td>
</tr>
<tr>
<td>Environment</td>
<td>Saved CO₂/kWh</td>
<td>Saved CO₂ emissions based on 30 and 60 g/kWh for PV and CSP life cycle emissions. Compared to business-as-usual with 780 g/kWh for conventional energy.</td>
<td>12</td>
</tr>
</tbody>
</table>

Table 22: Description of scenario performance indicators
Source: own elaboration

65 It is assumed that project developers calculate with investment costs of the year of submitting the project proposal, not the year of scheduled commissioning.
8.2 Results

8.2.1 Indicators

The scenario results show that the MSP can be realized by investing approximately 3.7 - 7.5 billion EUR which is found to be less than the expected 9 billion EUR by the Moroccan government (MEMEE, 2009a). Another surprising fact is that from a plant lifetime perspective the DC are negative even for the more expensive scenarios with large amount of CSP penetration. The total lifetime DC for the MSP depend on the technology and installed capacity, the resulting total energy yield, the corresponding individual LCOE and the (escalated) production costs until 2020. They are calculated by aggregating the total lifetime DC (see section 5.2) for every plant installed from 2014 - 2020. Given 3% escalation of production costs employing solar energy leads to an economic advantage of 4.7 to 2.8 billion EUR until 2050 (not discounted, assumptions see section 5.2). If these numbers are discounted by 10% annually, scenario A and B still reach negative DC of 254 and 68.5 million EUR respectively. Scenario C and D become more costly than a business as usual scenario - about 169 and 391 million EUR. The average LCOE realized within the complete MSP range between 8.3 - 11.7 EURct/kWh depending on the scenario. Thus, in all scenarios solar energy imposes low costs on the Moroccan economy from a long-term perspective.

<table>
<thead>
<tr>
<th></th>
<th>Scenario A)</th>
<th>Scenario B)</th>
<th>Scenario C)</th>
<th>Scenario D)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 billion EUR</td>
<td>10.6</td>
<td>15.1</td>
<td>18.8</td>
<td>24.3</td>
</tr>
<tr>
<td>2 EURct/kWh</td>
<td>8.3</td>
<td>9.6</td>
<td>10.7</td>
<td>11.7</td>
</tr>
<tr>
<td>3 million EUR</td>
<td>-4,738</td>
<td>-4,423</td>
<td>-3,437</td>
<td>-2,836</td>
</tr>
<tr>
<td>4 EURct/kWh</td>
<td>-3.70</td>
<td>-2.80</td>
<td>-2.0</td>
<td>-1.37</td>
</tr>
<tr>
<td>Energy Yield</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 GWh/a</td>
<td>4,267</td>
<td>5,274</td>
<td>5,833.4</td>
<td>6,914</td>
</tr>
<tr>
<td>6 %</td>
<td>7.9</td>
<td>9.7</td>
<td>10.8</td>
<td>12.8</td>
</tr>
<tr>
<td>Capital requirement</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7 million EUR</td>
<td>3,652</td>
<td>4,956</td>
<td>5,960</td>
<td>7,474</td>
</tr>
<tr>
<td>8 EUR/kWh</td>
<td>2.9</td>
<td>3.1</td>
<td>3.4</td>
<td>3.6</td>
</tr>
<tr>
<td>9 EUR/kW</td>
<td>1826</td>
<td>2478</td>
<td>2980</td>
<td>3737</td>
</tr>
<tr>
<td>Peak shaving</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10 EUR/kW</td>
<td>6,068</td>
<td>5,543</td>
<td>4,968</td>
<td>4,218</td>
</tr>
<tr>
<td>11 MW</td>
<td>150</td>
<td>675</td>
<td>1,250</td>
<td>2,000</td>
</tr>
<tr>
<td>Environment</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12 g/kWh</td>
<td>644</td>
<td>653</td>
<td>662</td>
<td>670</td>
</tr>
</tbody>
</table>

Table 23: Results for scenario performance indicators
Source: own elaboration

Energy production significantly differs in all scenarios ranging from 4.3 - 6.9 TWh/y (if all plants are operating from 2020 - 2044. These figures represent 7.9 - 12.8 % of the electricity consumption in 2020 assuming 7% growth of consumption per year. The scenarios with high penetration of CSP yield more energy due a higher capacity factor of plants. It becomes clear that if Morocco wants to
achieve a solar share of 14% (see section 2.4) more than 2000 MW of capacity needs to be installed, especially if PV is used. Alternatively CSP with a higher SM could be employed.

For scenario A around 6 GW additional conventional capacities are needed until 2020 to cover the annual peak load. For scenario D it is only around 4.2 GW. Because of the higher energy yield the total environmental impact of the complete MSP is most beneficial in scenario D with 118 billion tons of avoided CO₂ instead of 70 billion tons in scenario A. All indicators are summarized in Table 23 and graphically displayed in Figure 31.

8.2.2 Break-even

From an economic point of view it is especially interesting when conventional power is as expensive as solar energy (DC per unit energy = 0). This section analysis the break-even between conventional and solar power for the four MSP-scenarios.

Figure 32 shows the total annual DC for each scenario (grey area). For scenario A, break-even is in year 2021, for scenario B in 2024, for scenario C in 2027 and for scenario D in 2030. If the area above the x-axis is smaller than below, the MSP is economic from a lifetime perspective. The black area in Figure 32 shows the DC discounted by 10% per year. Consequently, future benefits (negative DC) equal almost zero, because they occur very late. On the other hand also the costs until break-even have a lower present worth. Scenarios with a lower share of CSP reach the break-even also earlier if DC are discounted.
However, all break even points depend heavily on LCOE and production cost assumptions. The sensitivity analysis in section 8.3 for example shows significant reaction to changes of escalation of production costs.

8.2.3 Impact on Residual Load

Figure 40 shows the impact of the MSP on the load exemplarily for the scenarios A (only PV) and D (only CSP) for a summer week in the year 2020. To get the load curve for 2020, the values of 2010 are increased by 7% p.a. equally over all values.

It is clearly visible that the scenarios with a higher share of CSP have a more desirable impact on the load. On one hand they can almost always run on full capacity (each plant output ~50 MW) and produce more energy due to storage and SM 2. On the other hand they shave the evening peak of the load. The PV penetration correlates with the mid-day peak while the evening peak is not
affected. Especially in summer penetration of solar power is high, because more irradiation is available and solar power production starts already very early and ends late (for a typical contribution to cover the load for all scenarios A-D in a summer and winter week see appendix I).

The maximum annual share of CSP energy contributing to the actual load is approximately 0%, 14.8%, 27.3% and 43.7% for the four scenarios A, B, C and D respectively. The maximum share of hourly PV penetration is approximately 40.2%, 32.4%, 18.0% and 0% for the four scenarios A, B, C and D in 2020 respectively. If taken together CSP and PV may provide up to 30.9%, 34.9%, 38.4% and 43.7% of the load in the hour of maximum annual penetration. The duration curve of solar power penetration is exemplarily displayed in Figure 34. Note that in general the CSP penetration could be dispatched differently (i.e. constant base load).

![Figure 34: Duration curve of solar penetration for scenario A - D](source: own elaboration)

### 8.3 Sensitivity Analysis

In the following it is assessed how the total discounted DC for the complete MSP (2014-2049) change if the escalation rate for production costs, the value of the baseline values (initial production costs for conventionals in 2010) and the financial conditions varies. For scenario A (only PV) and D (only CSP) the effect are analyzed for the case that: The escalation rate varies between 1% to 5% and for each of these rates the initial production costs for conventionals in 2010 represent either 100%, 85% or 70% of the baseline values - all these changes for the following different financial scenarios:

- Expensive money scenario: 12% debt 8% equity (WACC: 9.2%)
Scenarios Analysis for the MSP

- Base scenario identical as in section 8.2: 6% debt 10% equity (WACC: 7.2%)
- Cheap money scenario: 5% debt, 8% equity (WACC: 5.9%)
- Soft loan: 5% debt, 3% equity (WACC: 4.4%)

The results are graphically displayed in Table 24. They show that the better the achieved financial condition, the more scenario variations have negative DC for solar energy.

<table>
<thead>
<tr>
<th>Financing</th>
<th>Scenario A</th>
<th>Scenario D</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expensive</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WACC: 9.2%</td>
<td><img src="image1" alt="Graph" /></td>
<td><img src="image2" alt="Graph" /></td>
</tr>
<tr>
<td>(12% equity / 8% loan)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Base</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WACC: 7.2%</td>
<td><img src="image3" alt="Graph" /></td>
<td><img src="image4" alt="Graph" /></td>
</tr>
<tr>
<td>(10% equity / 6% loan)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cheap</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WACC: 5.9%</td>
<td><img src="image5" alt="Graph" /></td>
<td><img src="image6" alt="Graph" /></td>
</tr>
<tr>
<td>(8% equity / 5% loan)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Soft loan</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WACC: 4.4%</td>
<td><img src="image7" alt="Graph" /></td>
<td><img src="image8" alt="Graph" /></td>
</tr>
<tr>
<td>(3% equity / 5% loan)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

For all scenarios: DC are discounted by 10% per year; the legends in each figure refer to % of baseline values.

Table 24: Results of the sensitivity analysis for the MSP scenarios A and D
Source: own elaboration
It is especially remarkable that for scenario A given the cheap and soft loan scenarios the DC are negative for almost all different combinations of escalation rate and initial production costs. Thus, if the according financial conditions are achievable, solar energy is economically preferable compared with conventional energies almost regardless of the future cost developments or errors in estimation of production costs for conventionals (in the range of -30% compared to the baseline values). For CSP (scenario D), the risk to have positive DC costs is always higher, but under some circumstances the DC are also negative: this is when the escalation rate is higher than ~3.6% in the base scenario, higher than ~3% in the cheap scenario and higher than ~2.3% in the soft loan scenario (given 100% initial production costs for conventionals).

All in all, DC for all scenarios are relatively low or even negative if compared to business-as-usual scenarios. Note also that no environmental costs are internalized in any analysis within the scope of this work.

8.4 National Feed-In Tariff

Final decisions for the institutional financing mechanisms for the MSP have not yet been taken. For the first stages of the MSP MASEN is looking for donors and investors right now. Support could be achieved from the World Bank and the German government. However, a holistic financing scheme is not introduced yet. The Moroccan government expects investments in the range of 9 billion EUR (MEMEE, 2009a). The four analyzed scenarios require investments in the order of 3.7 - 7.5 billion EUR until 2020. This enormous investment will very likely not be funded completely by international institutions.

This chapter discusses the possibility to attract private investors by guaranteeing a feed-in tariff by law with fixed PPA-prices according to the LCOE calculated in the context of this work. The resulting DC calculated in the previous analysis can be distributed among the end-consumers of electricity. This is done on an energy consumption based approach in various countries for example in Germany. On the one hand every end-consumer pays an extra charge per kWh for all electricity he consumes (regardless if generated by RE or not). On the other hand investors of RE receive the electricity price according to the feed-in tariff in the respective year and site.

Exemptions from extra charges could be done based on consumption rates. This way low-income population would not be obliged to carry the financial burden of RE. The feasibility of the approach depends on the amount of extra charge and thus, the burden for end-consumers which is influenced especially by:

- the total electricity consumption per year (thus, on growth rates in the future)

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66 Exceptions are made in Germany for example for some energy-intensive industries.
For the analysis conducted two scenarios for the future electricity growth are assumed applying different growth (rapid and moderate, see Figure 35). The necessary extra charge for each year is calculated for each combination of financial and MSP-scenarios developed in chapter 8 (base, expensive, cheap and soft loan for each of the scenarios A - D) under the assumption of 3% escalation of production costs for conventionals and 100% baseline values. Simply, the total annual DC of each scenario is divided by the projected electricity generation in the corresponding year. The total annual energy yield is calculated by aggregating the annual power output of all plants installed in the respective year. The total annual total DC equal the aggregated DC of all plants for that year according to section 5.2.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Growth rate p.a. until</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2020</td>
</tr>
<tr>
<td><strong>Rapid Growth</strong></td>
<td>7%</td>
</tr>
<tr>
<td><strong>Moderate growth</strong></td>
<td>5%</td>
</tr>
</tbody>
</table>

![Figure 35: Assumed scenarios for electricity growth](source: own elaboration)

The results are shown in Figure 36 for all scenarios A-D under base scenario financial assumptions for rapid and moderate growth of electricity consumption. The extra charge rapidly increases in the beginning when plants are installed and it peaks already between 2015 and 2019. Then the burden declines until the DC reach break-even between 2025.

The weighted average extra charge to be paid by the consumer in scenario A for example is either 0.105 EURct/kWh or 0.114 EURct/kWh under rapid and moderate growth assumptions respectively. For the most expensive scenario with only CSP employment the weighted average extra charge would be 0.22 EURct/kWh or 0.26 EURct/kWh. Thus, the extra charge does not vary very heavily if the growth of electricity consumption varies in the range of 5% - 7% in the first ten years, especially for cheaper MSP-scenarios.

The electricity price in Morocco today varies roughly between 5 - 13 EURct/kWh depending on the type of consumer. The average extra charge accordingly represents for example 0.8% and 2.3% of today’s electricity price for scenario A and 1.1% - 5.2% for scenario D depending on electricity growth and tariff of the end-consumer. Already after break-even the extra charge is obsolete and the
average electricity price in Morocco should tend to decrease or at least escalate less fast compared to a business-as-usual scenario, because in contrary to conventional energies all solar plants run at constant costs until 2044 - 2049.

The results are based on the assumption that a feed-in tariff identical with the LCOE for the base scenario is offered (for each plant, site and year on an individual base). Then, given that all other assumptions are valid investors would achieve a rate of return of up to 7.2% (the rate of return is equal to the WACC assumed for the calculation of the LCOE in the base scenario).

In general, it could be the case that the rate of return is not enough to sustainably attract investors or in contrary that the Moroccan government wants to try to attract investments with a lower WACC. In this case, higher or lower feed-in tariffs need to be offered which increases or decreases the DC to be covered. Consequently, the extra charge would differ from the base scenario. This effect is assessed for the three additional scenarios developed in the sensitivity analyses. Feed-in tariffs according to these scenarios would offer 9.2%, 5.9% and 4.4% rate of return for investors for the expensive, cheap and soft loan scenario respectively. The weighted average extra charge in these case would range from 0.02 - 0.4 EURct/kWh representing between 0.4% - 8.1% of today’s electricity price depending on the end-consumer tariff and electricity consumption.

The development of the extra charge until break-even for all four scenarios is displayed in appendix J. For the rapid growth scenario the bandwidth of the extra charge in percent of today’s electricity price is displayed in Figure 37. Note that the influence of the offered rate of return is very important to limit the bandwidth. Thus, choosing a feed-in tariff which sustainably attracts sufficient investments, but minimizes the DC and burden for the end-consumer is the crucial factor for a successful strategy.
Figure 37: Bandwidth of extra charge in % of today’s electricity price (5 - 13 EURct/kWh)
Source: own elaboration
9 Conclusion

9.1 Summary of Results

In the last decade the expansion of installed capacity was at the edge to keep pace with Morocco’s growth of electricity consumption. This study showed that the Moroccan Solar Plan (MSP) - fostering 2000 MW of solar energy generation capacity until 2020 - will successfully contribute to diversify and green the generation capacity in Morocco. The simulation of different PV (fixed, 1-axis horizontal, 1-axis vertical and 2-axis) and CSP systems (with 0, 6, 12 and 18 full load hours storage) in sites of the MSP delivered a wide range of indicators to judge about the performance of solar energy in Morocco. A good suitability for solar energy – technically and economically – can be approved.

Some of the gained performance data is revised within this summary, but most of the data is to be found in chapter 6 – 8 and in detail in the appendices. All analysis of the MSP was based on DNI and GHI data from HelioClim differing between 1,927 - 2,428 kWh/m²/y and 1,968 - 2,154 kWh/m²/y respectively for all sites. It is to be noticed that the obtained data deviates from the long-term average data of HelioClim (1985 - 2004) in the range of -11.3% to 11.6% (DNI) and -1.5% to 8.6% (GHI). Therefore, uncertainty additionally to technical and economic assumptions as well as possible errors included in the long-term data is involved in all results. However, all results represent a reasonable estimate of reality and are additionally subject to a sensitivity analysis.

Technical simulation

The energy yields vary strongly depending on the specific technology. Comparing only the locations, in most of the cases the energy yield is 1% - 10% less than in the best site which is Ouarazate. Only Tarfaya shows a significantly worse performance (up to -25%), but is likely to be underestimated as irradiation is 11.3% lower than the long-term average. Capacity factors range between 17.9 - 24.3%, 37.3% - 46.8%, 55.4% - 69.1%, 69.7% - 81.1% for SM 1, 2, 3 and 4 respectively and between 17.8 - 19.6%, 23.5% - 21.8%, 21.5% - 23.9% and 23.7% - 26.0% for PV 1 - 4. The irradiation to net electricity efficiency ranges between 12.5% - 16.9% for CSP and 7.3% - 8.4% for PV.

In the case of CSP the solar field efficiency ranges between 46.3% - 48.9%. The net power efficiency of the power block is 32.9 - 36.9% depending on the SM, site and type of cooling. For PV the COS-losses and the module and inverter efficiency are decisive: they are for example in Ouarazate 72.9% - 100%, 13.9 - 14.1% and 97.3 - 97.4% respectively and depend on the tracking system (total derate factors account for 84.6%).
For most technologies the best sites in terms of energy yield in descending order are Ouarzazate, Ain Ben Mathar, Boujdour, Laayoune and Tarfaya (based on irradiation data of 2005). The order changes for a few cases: especially remarkable is only that Ain Ben Mathar shows second best performance for all PV technologies, but only fourth best performance for CSP due to the low share of beam irradiation at the site.

**Economic simulation**

The economic analysis shows that LCOE for PV can be as low as 9.6 EURct/kWh in 2012 and may even decrease to only 5.4 EURct/kWh in 2020. The bandwidth of variation among sites and technologies is narrow and decreasing from 0.90 EURct/kWh in 2012 to 1.55 EURct/kWh in 2020 for PV. CSP offers minimum LCOE of 12.8 - 9.2 EURct/kWh and a bandwidth between 2.3 - 1.6 EURct/kWh (2012 – 2020).

The long-term DC over a 30-years period show that solar energy is competitive very soon if a constant escalation rate of production costs for the conventional power system of 3% per year is assumed until 2050: The cheapest PV technology in the best site reaches then at average DC of 0.4 EURct/kWh for plants built in 2012 and -7.7 EURct/kWh for plants built in 2020. CSP has DC of 1.3 EURct/kWh in 2012 and -3.5 EURct/kWh in 2020. PV is found to be cheaper in all cases for both -LCOE and DC – mainly due to higher learning curves and less initial investment (and thus, lower capital costs). The cheapest technologies in terms of DC are horizontal 1-axis tracking (partly 2-axis tracking) for PV and SM 2 for CSP.  

The sensitivity analysis shows that LCOE heavily depend on financial assumptions, especially on the WACC. The impact of the expensive, cheap and soft loan scenarios is up to 17%, -16% and -27% on the base scenario LCOE (WACC of 9.2%, 5.9% and 4.4% respectively). LCOE are relatively insensitive towards Opex. The DC react very sensitive if the escalation rate for production costs of the conventional power system is changed: For a 50 MW PV 1 plant built in 2015, the break-even with the conventional system in Morocco shifts for example from year 2028 to 2034 if an escalation rate of 2.5% instead of 3.5% is assumed (break-even at 2.95%). Higher evening peaks or lower mid-day peaks in the daily load improve the economics in terms of DC for CSP compared to PV (and vice versa), but cannot render CSP less expensive unless very drastic scenarios are assumed.

**Simulation of MSP scenarios**

To get an impression about the overall impact of the MSP, four scenarios with different shares of CSP and PV utilization were analyzed (A: 150 MW CSP and 1850 MW PV; B: 1325 MW and 675 MW; C:

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67 Base scenario assumptions: Specific investment costs between 2,566 – 9,728 EUR/kW for CSP SM 1 – 4 and 2,400 – 2,920 EUR/kW for PV 1 – 4, WACC is 7.2%, O&M costs 1.5% of investment for CSP and 0.35% - 0.73% for PV, loan term 30 years, learning rates 5 – 20%. 

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750 MW and 1250 MW; D: 0 MW and 2000 MW). The total investments required for the four scenarios range between 3.7 - 7.5 billion EUR and thus, are less than the 9 billion EUR expected from the Moroccan government. Once all plants are online, 4.3 - 6.9 TWh/y of electric energy are produced which accounts for 7.9% - 12.8% of the electricity demand in the year 2020 if a growth rate of 7% per year is assumed.

The maximum annual penetration of solar energy is depending on the scenario 30.9% - 43.7% of the Moroccan load. The scenarios with a higher share of CSP clearly have a more desirable impact as they are able to shave the characteristic, daily (absolute) peak in the evening. In contrary, power production of PV occurs only during sunshine hours. These effects reduce the need for additional, conventional capacities until 2020 from 6 GW in scenario A (only PV) to 4.2 GW in scenario D (only CSP). CSP has also the advantage to provide the full range of auxiliary services for the grid (active, reactive and reserve power control) as it delivers dispatch able power. The effect of intermittent power output on the power quality and grid stability under Moroccan conditions for utility-scale PV is unclear and may represent an (initial) integration barrier.

The average LCOE realized within the complete MSP range between 8.3 - 11.7 EURct/kWh depending on the scenario - with lower values occurring in scenarios with high PV utilization. The total DC of the MSP until 2020 are negative and in the order of 2.8 - 4.7 billion EUR until 2050 (not discounted, 3% escalation of conventional system costs, 100% baseline values). If these numbers are discounted by 10% annually, scenario A and B still reach negative DC of 254 and 68.5 million EUR respectively. Scenario C and D become more costly than a business-as-usual scenario - about 169 and 391 million EUR. Negative DC indicate that solar energy imposes lower costs on the Moroccan economy than conventional energies. Break-even in terms of DC is reached between 2021 and 2030 for the complete MSP depending on the ratio of PV and CSP utilization (scenarios with a higher share of PV reach break-even faster).

The sensitivity analysis shows that also under different financing conditions (WACC: 9.2%, 5.9% and 4.4%), different initial production costs for conventionalals (100%, 85% and 70% of baseline values) and different respective escalation rates (1% - 5%) a surprisingly high number of possible scenarios for the MSP have negative DC (for scenario A in 55 out of 72 cases and for scenario D in 22 cases out of 72). Note also that no environmental costs for the conventional electricity generation have been internalized although the total environmental benefit of the MSP is ranging from 70 to 118 billion tons of avoided CO₂.

Considerations to introduce a national feed-in tariff in Morocco show that depending on the offered rate of return for investors (4.4% - 9.2% per year) and the DC, the weighted average extra charge to be paid by the consumer is between 0.02 - 0.4 EURct/kWh. This range represents between 0.4% -
8.1% of today’s electricity price. Choosing a feed-in tariff which sustainably attracts sufficient investments and minimizes the burden for the end-consumer is crucial. However, for a broad range of MSP scenarios and framework conditions a feed-in tariff does not need to be very costly.

9.2 Recommendations for Decision Makers

All in all, it is not possible to recommend an optimum utilization of PV and CSP within the MSP. Neither the LCOE approach nor the DC approach can prove that the dispatch ability of CSP is economically preferable. One might argue that no perfect approach was used within this work due to the lack of perfect modeling and the exact knowledge about avoided production costs of conventional. However, the simplified approach presented, suggests that it is not very likely that CSP will be less costly than PV even if an improved approach is used. Therefore, it remains rather a strategic decision whether cheaper solar energy (PV) or peak-shaving capacity (CSP) is employed. However, some recommendations regarding the PV/CSP utilization can be made:

- The higher the growth of annual maximum peak demand, the more CSP should be employed; the lower the peak, the more PV can be used
- A clear energy target for 2020 should be defined beside the capacity target to push decision making towards the adequate technologies (high target requires more CSP with storage, lower targets can cope with PV)
- A target for tolerable DC should be defined and research on past and future escalation of production costs helps to estimate the ratio of CSP and PV which is bankable (if escalation is high, more CSP can be employed at a lower risk avoiding drastic increases of DC)

Generally it is recommended that decision makers:

- Confirm the level of irradiation at sites of the MSP by continuous ground measurements in order to have more reliable information about the competitiveness of all sites
- re-evaluate the site of Tarfaya as all public data free of charge indicate that it is the site of lowest irradiation within the MSP (eventually build only 100 MW in Tarfaya and instead 500 MW in Boujdour or even take other sites into consideration)
- Initiate the research on intermittency and grid impact of PV to ensure its feasibility and start pilot projects for utility-scale PV (>1 MW) as soon as possible in 2012
- Develop a distributed generation strategy for PV which allows for smoother integration
- Include long-term thinking within the economic analysis and judgment: PPA projects for solar energy allow to introduce non-escalating cost components in the electricity mix which can be crucial if real fuel price escalation (and inflation) accelerates in the future
- Ensure that cheap financial framework conditions for the MSP and single projects are achieved as it is the most important driver to decrease the DC
- Design a feed-in tariff concept if sufficient financing is not in sight including: decisions on an adequate rate of return for investors, a budget for tolerable annual DC, a corresponding or politically defined limit for the extra charge, exemptions from payment for low-income consumers and specific PPA prices based on site and year
- Draw conclusions from the tender results of the first stage in Ouarzazate indicating an achievable compromise between attractiveness for investors and low DC
- Monitor the DC occurring for the first project in Ouarzazate with a specific focus on the avoided production costs of the conventional power system
Appendices

Appendix A - acknowledgments: Institutions and interviewees visited in Morocco

<table>
<thead>
<tr>
<th>Interviewee</th>
<th>Institution / Function</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dieter Uh</td>
<td>GIZ - Morocco / Head of office &amp; RE expert</td>
<td>8 / 18 / 2011</td>
</tr>
<tr>
<td>Obaid Amrane</td>
<td>MASEN / Board Member</td>
<td>9 / 12 / 2011</td>
</tr>
<tr>
<td>Mohamed Mouchtakiri</td>
<td>ONE - Leader of the dispatch center</td>
<td>9 / 9 / 2011</td>
</tr>
<tr>
<td>Abdellah Griech</td>
<td>ONE - Head of Renewable Energy Division</td>
<td>18 / 9 / 2011</td>
</tr>
<tr>
<td>Reda Znaidi</td>
<td>NAREVA Holding</td>
<td>18 / 9 / 2011</td>
</tr>
<tr>
<td>Habib Elandaloussi</td>
<td>Paving the Way for the Mediterranean Solar Plan - Deputy Team Leader</td>
<td>9 / 15 / 2011</td>
</tr>
<tr>
<td>Mustapha Enzili</td>
<td>ADEREEE - Head of Wind Energy Division</td>
<td>8 / 23 / 2011</td>
</tr>
<tr>
<td>Dr. Amine Bennouna</td>
<td>Istichar Consulting</td>
<td>8 / 28 / 2011</td>
</tr>
</tbody>
</table>

Table 25: Institutions and interviewees visited during the field research  
Source: own elaboration

Appendix B - section 3.3: Monthly wind speed and ambient temperature for sites of the MSP

Figure 38: Average monthly wind speed in sites of the MSP  
Source: own elaboration

Figure 39: Average ambient temperature for sites of the MSP  
Source: own elaboration
Appendix C - section 4.1.1: Formulas of solar geometry

The formulas summarized in this annex are required to calculate the incidence angle on the aperture area of collectors. They have been used for the hourly calculation of the COS-loss coefficient. The applied solar geometry has been described in detail in (Duffie/Beckmann, 1991). All definitions and formulas have been taken from this reference.

\( \theta \) = Incidence Angle

The angle between the beam radiation on the aperture area and the normal of the aperture area.

\[
\cos \theta = \cos \theta_z \cos \beta + \sin \theta_z \sin \beta \cos(|\gamma_s - \gamma|) \quad A.1
\]

\( \theta_z \) = Zenith angle

The angle of incidence of beam irradiation on a horizontal surface.

\[
\cos \theta_z = (\cos \varphi \cos \delta \cos \omega + \sin \delta \sin \varphi) \quad A.2
\]

\( \beta \) = slope

The angle between aperture area and the horizontal.

\[
\tan \beta = \tan \theta_z \cos(\gamma_s - \gamma) \quad A.3
\]

\( \gamma_s \) = Solar azimuth angle

The angular displacement from south of the projection of beam radiation on the horizontal plane.

\[
\cos \gamma_s = \cos \theta_z \sin \varphi - \frac{\sin \delta}{\sin \theta_z \cos \varphi} \quad A.4
\]

\( \gamma \) = Surface azimuth angle

The deviation of the projection on a horizontal plane of the normal to the surface from the local meridian, with zero due south, east negative and west positive. For north-south axis tracking:

\[
\begin{align*}
IF \gamma_s < 0, \gamma &= -90^\circ \\
IF \gamma_s > 0, \gamma &= 90^\circ
\end{align*} \quad A.5
\]

\( \delta \) = Sun declination angle

The angular position of the sun at solar noon with respect to the plane of equator.

\[
\delta = 23.45 \sin(360 \times \frac{284 + n}{365}) \quad A.6
\]

\( \omega \) = hour angle

The angular displacement of the sun east or west of the local meridian due to rotation of the earth on its axis at 15\(^\circ\) per hour,
morning negative, afternoon positive.

\[ \omega = (H_{ST} - 12)15 \]  

\( H_{ST} \) = Hour of the day (ST)

Solar time (ST) is the time used in all of the sun angle relationships including correction for difference in longitude and perturbations in the earth’s rate of rotation.

\[ Solar \ time - standard \ time = 4(L_{st} - L_{loc}) + E \]  

\( E \) = Equation of time

Correction for perturbations in the earth’s rate of rotation in calculating the solar time.

\[ E = 229.2(0.000075 + 0.001868 \cos B \]
\[ - 0.032077 \sin B - 0.014615 \cos 2B \]
\[ - 0.04089 \sin 2B) \]  

where: \[ B = (n - 1) \frac{360}{365} \]

\( L_{st} \) = standard meridian for the local time zone

\( L_{loc} \) = longitude of the site

\( n \) = day of the year

\( \phi \) = Latitude of the site

Appendix D - section 4.1.4: Calculation of parasitic load

To calculate the parasitic load formulas and procedure is adopted from (Trieb, 2004). Therefore, only very brief explanations are provided. For details see the corresponding document.

1. Wet cooling

Mass flow rate of steam and cooling water:

\[ m_{W}c_{PW}(T_{out} - T_{in}) = m_{steam}(h_4 - h_1) \]  

\( m_{W} \) = Mass flow rate of water

\( c_{PW} \) = Specific heat capacity of water

\( T_{out} \) = Outlet temperature of water

\( T_{in} \) = Inlet temperature of water

\( m_{steam} \) = Mass flow rate of steam

\( h_4 \) = Enthalpy of steam at outlet

\( h_1 \) = Enthalpy of steam at inlet

\( A.7 \)

\( A.8 \)

\( A.9 \)

\( A.10 \)
Where, $c_{pw} = 4.18 \text{ kJ/kgK}$, $T_{out} = \text{temperature of cooling water at outlet} = 30^\circ C$, $T_{in} = \text{temperature of cooling water at inlet} = 20^\circ C$, $m_w = \text{mass flow rate water}$, $m_{steam} = \text{mass flow rate of steam}$, $h_4 - h_1 = \text{enthalpy drop in condenser}$

**Parasitics of cooling cycle pump ($L_{p,CP}$):**

$$P_{CP} = m_w(\Delta z g + \frac{w^2}{2} \left( 1 + \kappa_{in} + \kappa_{out} + \kappa_{filter} + \kappa_{cond} + 4\kappa_{kr} + \frac{U \cdot 2L}{d} \right)) \frac{1}{\eta_{CP}} \quad A.11$$

Where, $\Delta z = \text{difference in altitude between cooling water inlet and outlet} = 1$, $g = \text{gravitation constant} = 9.81 \text{ m/s}^2$, $w = \text{velocity of cooling water} = \frac{m_w}{d^2 \pi}$, $\eta_{CP} = \text{efficiency of cooling pump}$, $\kappa = \text{loss coefficient of inlet, outlet, filter and condenser}$, $U = \text{pipe roughness}$, $L = \text{distance between condenser and cooling water reservoir}$, $\eta_{CP} = \text{efficiency of cooling pump}$, $d = \text{diameter of cooling pipe} = \sqrt{\frac{m_{w,\text{nom}}^4}{w_{\text{nom}} \pi}}$ and $CP = \text{supply pump}$.

**Parasitics of supply pump ($L_{p,SP}$):**

For the supply pump a recovery turbine is used which reduces the parasitic load needed to overcome the difference in altitude between see water inlet and supply pipe outlet (recovery turbine (part load) efficiency = $\eta_{WT} = 0.8$).

$$P_{SP} = m_w((\Delta z - 1)g(1 - \eta_{WT}) + \frac{w_{sp}^2}{2} \left( 2 + 2\kappa_{in} + 2\kappa_{out} + \kappa_{filter} + \kappa_{cond} + 4\kappa_{kr} + \frac{U_{sp} \cdot 2(L - 500)}{d_{sp}} \right)) \frac{1}{\eta_{SP}} \quad A.12$$

Where, symbols as above; $SP = \text{supply pump}$.

2. **Only Dry Cooling**

The calculation of the air mass required is analog to wet cooling. Of course, all values need to be taken for air instead of water. The parasitics for the ventilator ($L_V$) are:

$$L_V = m_L C_V \frac{1}{\eta_V} \quad A.13$$

Where, $m_{air} = \text{mass of air stream}$, $\eta_V = (\text{part load}) \text{efficiency of ventilator}$ and $C_V = \frac{\Delta p_V}{\rho_{air} m_{L,\text{nom}}}$ = ventilator constant, with $\Delta p_V = \text{nominal pressure loss of system}$, $\rho_{air} = \text{air density}$, $m_{air,\text{nom}} = \text{mass of air stream at nominal plant load}$. 


### Parameters for the SANDIA performance model

<table>
<thead>
<tr>
<th>Parameter (Unit)</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$I_{SC}$ (A)</td>
<td>Short circuit current of the module under STC.</td>
<td>8.222</td>
</tr>
<tr>
<td>$I_{MP}$ (A)</td>
<td>Maximum power point current of the module under STC.</td>
<td>7.727</td>
</tr>
<tr>
<td>$V_{MP}$ (V)</td>
<td>Maximum power point voltage of the module under STC.</td>
<td>29.886</td>
</tr>
<tr>
<td>$\alpha_{isc}$ (1/°C)</td>
<td>Normalized temperature coefficient for $I_{SC}$.</td>
<td>0.000746</td>
</tr>
<tr>
<td>$\alpha_{imp}$ (1/°C)</td>
<td>Normalized temperature coefficient for $I_{MP}$.</td>
<td>0.000176</td>
</tr>
<tr>
<td>$C_0$</td>
<td>Empirically determined coefficients relating the maximum power point current to effective irradiance.</td>
<td>0.9993</td>
</tr>
<tr>
<td>$C_1$</td>
<td>Empirically determined coefficients relating the maximum power point voltage to effective irradiance.</td>
<td>-0.058706</td>
</tr>
<tr>
<td>$C_2$</td>
<td></td>
<td>-8.35334</td>
</tr>
<tr>
<td>$\theta_{VMP}$ (V/°C)</td>
<td>Temperature coefficient for module $V_{MP}$ at a 1000 W/m² irradiance level</td>
<td>-0.137</td>
</tr>
<tr>
<td>$n$</td>
<td>Empirically determined ‘diode factor’ associated with individual cells in the module.</td>
<td>1.263</td>
</tr>
<tr>
<td>$I_{REF}$ (W/m²)</td>
<td>Reference solar irradiance.</td>
<td>1000</td>
</tr>
<tr>
<td>$I_{E}$ (W/m²)</td>
<td>The ‘effective’ solar irradiance.</td>
<td>variable</td>
</tr>
<tr>
<td>$I_{D}$ (W/m²)</td>
<td>Diffuse component of solar irradiance incident on the module surface.</td>
<td>variable</td>
</tr>
<tr>
<td>$f_d$</td>
<td>Fraction of used diffused irradiation.</td>
<td>1</td>
</tr>
<tr>
<td>$a_0$</td>
<td>Empirically determined coefficients to calculate $f_d$(AMₐ).</td>
<td>0.9011</td>
</tr>
<tr>
<td>$a_1$</td>
<td></td>
<td>0.1021</td>
</tr>
<tr>
<td>$a_2$</td>
<td></td>
<td>-0.02942</td>
</tr>
<tr>
<td>$a_3$</td>
<td></td>
<td>0.00397</td>
</tr>
<tr>
<td>$a_4$</td>
<td></td>
<td>-0.0002105</td>
</tr>
<tr>
<td>$b_0$</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>$b_1$</td>
<td></td>
<td>-0.002438</td>
</tr>
<tr>
<td>$b_2$</td>
<td></td>
<td>0.003103</td>
</tr>
<tr>
<td>$b_3$</td>
<td></td>
<td>-0.0001246</td>
</tr>
<tr>
<td>$b_4$</td>
<td></td>
<td>2.11E-07</td>
</tr>
<tr>
<td>$b_5$</td>
<td></td>
<td>-1.36E-09</td>
</tr>
<tr>
<td>$k$ (J/K)</td>
<td>Boltzmann’s constant.</td>
<td>1.38066E-23</td>
</tr>
<tr>
<td>$q$ (C)</td>
<td>Elementary charge.</td>
<td>1.60218E-19</td>
</tr>
<tr>
<td>$N_s$</td>
<td>Number of cells in series in a modules’ cell string.</td>
<td>60</td>
</tr>
<tr>
<td>$T_0$ (°C)</td>
<td>Reference cell temperature.</td>
<td>25</td>
</tr>
<tr>
<td>$T_c$ (°C)</td>
<td>Cell temperature inside module.</td>
<td>Variable</td>
</tr>
<tr>
<td>$AOI$</td>
<td>Angle of Incidence.</td>
<td>Variable</td>
</tr>
<tr>
<td>$AM$</td>
<td>Air mass.</td>
<td></td>
</tr>
</tbody>
</table>

### Parameters for the temperature correction factor

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\Delta T$</td>
<td>The temperature difference between the cell and module back surface at the reference incident radiation of 1000 W/m²</td>
<td>3</td>
</tr>
<tr>
<td>$a$</td>
<td>Empirically-determined coefficient establishing the upper limit for module temperature at low wind speeds and high solar irradiance.</td>
<td>-3.348</td>
</tr>
<tr>
<td>$b$</td>
<td>Empirically-determined coefficient establishing the rate at which module temperature drops as wind speed increases.</td>
<td>-0.09143</td>
</tr>
<tr>
<td>$\delta$ (%/°C)</td>
<td>Maximum power temperature coefficient for monocrystalline silicon cells.</td>
<td>-0.4408</td>
</tr>
<tr>
<td>$I_{incident}$ (W/m²)</td>
<td>Total incident irradiation on module surface.</td>
<td></td>
</tr>
</tbody>
</table>

### General PV module characteristics

- (W peak) Nameplate capacity of module: 230
- (m²) Area of one cell in the module: 0.024336
- (m²) Total cell area per module: 1.46016
- (m²) Area of one single module: 1.634

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
</table>

Table 26: Parameters for the SANDIA module model - Yingli Solar YL230-29b
Source: own elaboration, data taken from (King, 2004)
### Appendix F - section 6.1: Technical indicators for all sites

The following table summarizes the main technical parameters for a 50 MW reference plant for all technologies and all locations. The values in the table are ordered vertically according to the following sites: Ouarazate, Ain Ben Mathar, Boujdour, Laayoune and Tarfaya. If there is a single value listed for one indicator it is valid for all location.

<table>
<thead>
<tr>
<th>Technology</th>
<th>CSP</th>
<th>PV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SM 1</td>
<td>SM 2</td>
</tr>
<tr>
<td>Annual irradiation (kWh/a)</td>
<td>2428</td>
<td>2369</td>
</tr>
<tr>
<td>Higher irradiation yield</td>
<td>-</td>
<td>100%</td>
</tr>
<tr>
<td>Annual net energy yield (GWh&lt;sub&gt;el&lt;/sub&gt;):</td>
<td>97.7</td>
<td>185.9</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>24.3%</td>
<td>46.8%</td>
</tr>
<tr>
<td>Irradiation to net electricity conversion&lt;sup&gt;68&lt;/sup&gt;</td>
<td>15.4%</td>
<td>14.7%</td>
</tr>
<tr>
<td>Total full load hours</td>
<td>2131</td>
<td>4099</td>
</tr>
</tbody>
</table>

Table 27: General technical parameters for all sites and technologies

Source: own elaboration

---

<sup>68</sup> Definition: Net annual energy yield over total annual irradiation received by the aperture area of collectors (CSP) / by the total cell area of modules (PV).
## CSP - performance characteristics

### Solar Field\(^69\) - All solar multiples

<table>
<thead>
<tr>
<th>Overall geometrical loss coefficient of solar field</th>
<th>Annual, average COS-loss</th>
<th>Annual, average IAM-loss</th>
<th>Annual, average Row-end loss coefficient</th>
<th>Overall optical loss coefficient</th>
<th>Total annual thermal loss coefficient(^70)</th>
<th>Solar Field reduction coefficient</th>
<th>Annual average solar field efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>86.1%</td>
<td>88.8%</td>
<td>96.9%</td>
<td>99.2%</td>
<td>73.3%</td>
<td>84.2%</td>
<td>98.5%</td>
<td>48.9%</td>
</tr>
<tr>
<td>84.7%</td>
<td>87.6%</td>
<td>97.1%</td>
<td>99.1%</td>
<td></td>
<td>83.4%</td>
<td>98.5%</td>
<td>46.9%</td>
</tr>
<tr>
<td>87.9%</td>
<td>90.2%</td>
<td>94.6%</td>
<td>99.4%</td>
<td></td>
<td>82.5%</td>
<td>98.5%</td>
<td>48.7%</td>
</tr>
<tr>
<td>87.7%</td>
<td>90.3%</td>
<td>95.2%</td>
<td>99.3%</td>
<td></td>
<td>82.5%</td>
<td>98.4%</td>
<td>48.5%</td>
</tr>
<tr>
<td>87.1%</td>
<td>90.5%</td>
<td>95.0%</td>
<td>99.3%</td>
<td></td>
<td>80.2%</td>
<td>98.4%</td>
<td>46.3%</td>
</tr>
</tbody>
</table>

### Power Block

<table>
<thead>
<tr>
<th>SM 1</th>
<th>SM 2</th>
<th>SM 3</th>
<th>SM 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>33.0%</td>
<td>33.5%</td>
<td>33.2%</td>
<td>32.9%</td>
</tr>
<tr>
<td>32.9%</td>
<td>33.7%</td>
<td>33.4%</td>
<td>33.1%</td>
</tr>
<tr>
<td>35.6%</td>
<td>36.7%</td>
<td>36.3%</td>
<td>36.2%</td>
</tr>
<tr>
<td>35.4%</td>
<td>36.9%</td>
<td>36.5%</td>
<td>36.3%</td>
</tr>
</tbody>
</table>

### Parasitics (MW)

<table>
<thead>
<tr>
<th>Total Parasitics (MW)</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Parasitics (MW)</td>
<td>2.04</td>
<td>3.60</td>
<td>5.05</td>
<td>6.50</td>
</tr>
<tr>
<td>1.84</td>
<td>3.24</td>
<td>4.51</td>
<td>5.78</td>
<td></td>
</tr>
<tr>
<td>2.07</td>
<td>3.74</td>
<td>4.88</td>
<td>6.03</td>
<td></td>
</tr>
<tr>
<td>2.08</td>
<td>3.75</td>
<td>4.90</td>
<td>6.06</td>
<td></td>
</tr>
<tr>
<td>1.83</td>
<td>3.41</td>
<td>4.39</td>
<td>5.38</td>
<td></td>
</tr>
</tbody>
</table>

#### Table 28: CSP performance characteristics for all sites and technologies
Source: own elaboration

### PV - performance characteristics

<table>
<thead>
<tr>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average COS-loss coefficient</td>
<td>72.9%</td>
<td>88.8%</td>
<td>91.1%</td>
</tr>
<tr>
<td>73.0%</td>
<td>87.6%</td>
<td>92.2%</td>
<td>100.0%</td>
</tr>
<tr>
<td>70.2%</td>
<td>90.8%</td>
<td>87.8%</td>
<td>100.0%</td>
</tr>
<tr>
<td>70.8%</td>
<td>90.5%</td>
<td>88.6%</td>
<td>100.0%</td>
</tr>
<tr>
<td>69.9%</td>
<td>90.0%</td>
<td>88.4%</td>
<td>100.0%</td>
</tr>
<tr>
<td>Average module efficiency</td>
<td>14.1%</td>
<td>14.1%</td>
<td>14.0%</td>
</tr>
<tr>
<td>14.3%</td>
<td>14.4%</td>
<td>14.3%</td>
<td>14.2%</td>
</tr>
<tr>
<td>14.1%</td>
<td>14.4%</td>
<td>14.4%</td>
<td>14.3%</td>
</tr>
<tr>
<td>14.8%</td>
<td>14.6%</td>
<td>14.6%</td>
<td>14.5%</td>
</tr>
<tr>
<td>14.7%</td>
<td>14.6%</td>
<td>14.6%</td>
<td>14.5%</td>
</tr>
<tr>
<td>Average inverter efficiency</td>
<td>97.3%</td>
<td>97.4%</td>
<td>97.2%</td>
</tr>
<tr>
<td>97.4%</td>
<td>97.3%</td>
<td>97.3%</td>
<td>97.1%</td>
</tr>
<tr>
<td>97.4%</td>
<td>97.3%</td>
<td>97.2%</td>
<td>97.1%</td>
</tr>
<tr>
<td>97.5%</td>
<td>97.4%</td>
<td>97.4%</td>
<td>97.2%</td>
</tr>
<tr>
<td>Total pre-inverter derate</td>
<td>85.5%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Post-Inverter Derate</td>
<td>99.0%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Table 29: PV performance characteristics for all sites and technologies
Source: own elaboration

\(^69\) Efficiencies refer to irradiation weighted, average values (efficiency values during hours with high irradiation have higher weight) which have been calculated for operating hours of the solar field.

\(^70\) Coefficient relates total annual thermal losses to total annual normal direct irradiation on total aperture area of collectors.
## Appendix G - section 5.1: Capex for all technologies from 2011 - 2020

<table>
<thead>
<tr>
<th>Year</th>
<th>CSP (EUR/kW)</th>
<th>PV (EUR/kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SM 1</td>
<td>SM 2</td>
</tr>
<tr>
<td>2011</td>
<td>2439</td>
<td>100%</td>
</tr>
<tr>
<td>2012</td>
<td>2319</td>
<td>95%</td>
</tr>
<tr>
<td>2013</td>
<td>2206</td>
<td>90%</td>
</tr>
<tr>
<td>2014</td>
<td>2098</td>
<td>86%</td>
</tr>
<tr>
<td>2015</td>
<td>1997</td>
<td>82%</td>
</tr>
<tr>
<td>2016</td>
<td>1919</td>
<td>79%</td>
</tr>
<tr>
<td>2017</td>
<td>1844</td>
<td>76%</td>
</tr>
<tr>
<td>2018</td>
<td>1773</td>
<td>73%</td>
</tr>
<tr>
<td>2019</td>
<td>1704</td>
<td>70%</td>
</tr>
<tr>
<td>2020</td>
<td>1638</td>
<td>67%</td>
</tr>
</tbody>
</table>

**Table 30: Capex for all technologies 2011-2020**

*Source: own elaboration*
**Appendix H - section 7.1.2:** Economic indicators for all sites

LCOE and DC for all site and technologies from 2012 - 2020: The values in the table are ordered vertically according to the following sites: Ouarzazate, Ain Ben Mathar, Boujdour, Layyouna and Tarfaya.

![Table 31: LCOE and DC for all sites and technologies 2011 - 2020](source: own elaboration)
Appendix I - section 7.1.2: Impact on the Moroccan load in 2020 for the scenarios A - D

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Week in winter</th>
<th>Week in summer</th>
</tr>
</thead>
<tbody>
<tr>
<td>A)</td>
<td><img src="image1" alt="Graph A" /></td>
<td><img src="image2" alt="Graph A" /></td>
</tr>
<tr>
<td>B)</td>
<td><img src="image3" alt="Graph B" /></td>
<td><img src="image4" alt="Graph B" /></td>
</tr>
<tr>
<td>C)</td>
<td><img src="image5" alt="Graph C" /></td>
<td><img src="image6" alt="Graph C" /></td>
</tr>
<tr>
<td>D)</td>
<td><img src="image7" alt="Graph D" /></td>
<td><img src="image8" alt="Graph D" /></td>
</tr>
</tbody>
</table>

Figure 40: Impact on the load in 2020 of the scenarios A - D for a week in winter and summer
Source: own elaboration
### Appendix J - section 7.1.2: Extra charge for all scenarios given different rate of return for investors

<table>
<thead>
<tr>
<th>Financing</th>
<th>Rapide Growth</th>
<th>Moderate Growth</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Expensive</strong></td>
<td><img src="image1" alt="Graph" /></td>
<td><img src="image2" alt="Graph" /></td>
</tr>
<tr>
<td>Rate of return: 9.2% (12% equity / 8% loan)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Base</strong></td>
<td><img src="image3" alt="Graph" /></td>
<td><img src="image4" alt="Graph" /></td>
</tr>
<tr>
<td>Rate of return: 9.2% (12% equity / 8% loan)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Cheap</strong></td>
<td><img src="image5" alt="Graph" /></td>
<td><img src="image6" alt="Graph" /></td>
</tr>
<tr>
<td>Rate of return: 9.2% (12% equity / 8% loan)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Soft loan</strong></td>
<td><img src="image7" alt="Graph" /></td>
<td><img src="image8" alt="Graph" /></td>
</tr>
<tr>
<td>Rate of return: 9.2% (12% equity / 8% loan)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*For all scenarios: 3% escalation of production costs, use of baseline values*

Figure 41: Extra charge for combination of financial scenarios and rate of return for investors

*Source: own elaboration*
Bibliography


Trieb/Müller-Steinhagen/Kern. 2010. Financing concentrating solar power in the Middle East and North Africa - Subsidy or Investment?, MENASOL Morocco 2011, Casablanca


Declaration

To the best of my knowledge I do hereby declare that this thesis is my own work. It has not been submitted in any form or degree or diploma to any other university or other institution of education. Information derived from the published or unpublished work of others has been acknowledged in the text and a list of references is given.

Kassel, 2nd of February 2012

Christoph Richts