SES6-CT-2003-502578

ECOSTAR

European Concentrated Solar Thermal Road-Mapping

Roadmap Document

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European Concentrated Solar Thermal Road-Mapping

Coordination action
Sustainable Energy Systems

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Abbreviations

°C	Degrees Celsius
€	Euro
AA	Atmospheric Air
CIEMAT	Center for Energy, Environment and Technological Research
CNRS	French National Center for Scientific Research
CRS	Central Receiver System
CSP	Concentrating Solar Thermal Power
DLR	Deutsches Zentrum für Luft- und Raumfahrt e.V.
DNI	Direct Normal Insolation
DSG	Direct Steam Generation
E.ON	E.ON Energie AG
ETH	Eidgenössische Technische Hochschule, Zürich, Switzerland.
EU	European Union
FCR	Fixed Charge Rate
GWh	Gigawatt-hours
h	Hours
HCE	Heat Collection Elements
HTF	High Temperature Fluid
IEA	International Energy Agency
IVTAN	Institute for High Temperatures of the RAS, Ass. IVTAN, Moskau, Russia
kg	Kilograms
km^2	Square kilometre
kW	Kilowatts
kW_{el}	Kilowatts-electrical
kW_{th}	Kilowatts-thermal
LEC	Levelized Electricity Cost
m	Meter
m^2	square meter
m^3	cubic meter
MS	Molten Salt
MW	Megawatts
MW_{el}	Megawatts-electrical
MWh	Megawatt-hours
MW_{th}	Megawatts-thermal
O&M	Operating and Maintenance
PB	Power Block
PCM	Phase Changing Materials
PSA	Plataforma Solar de Almería
PURPA	U.S. Federal Public Utility Regulatory Policy Act
PV	Photo Voltaic
R&D	Research and Development
RES	Renewable Energy Source

RTILs	Room Temperature Ionic Liquids
s	Seconds
SCE	Southern California Edison
SEGS	Solar Electric Generating Station
SM	Solar Multiple
Solar PACES	Solar Power and Chemical Energy Systems
SOLGT	Solar Hybrid Gas Turbine
STEOR	Solar Thermal Enhanced Oil Recovery
t	Tons
TES	Thermal Energy Storage
TSA	Technology Program Solar Air Receiver, Germany
VGB	VGB PowerTech e.V.
WIS	Weizmann Institute of Science, Israel

1. Executive Summary

1.1. Purpose and scope

Recognising both the environmental and climatic hazards to be faced in the coming decades and the continued depletion of the world's most valuable fossil energy resources, **Concentrating Solar Thermal Power** (CSP) can provide critical solutions to global energy problems within a relatively short time frame and is capable of contributing substantially to carbon dioxide reduction efforts. Among all the renewable technologies available for large-scale power production today and for the next few decades, CSP is one with the potential to make major contributions of clean energy because of its relatively conventional technology and ease of scale-up.

Today's technology of CSP systems is implemented in the cost range of **15 - 20 cents€/kWh**. In the conventional power market, it competes with mid-load power in the range of 3 – 4 cents€/kWh. Sustainable market integration as predicted different scenarios can only be achieved, if the cost will be reduced in the next 10 to 15 years to a competitive cost level. Competitiveness is not only impacted by the cost of the technology itself but also by a potential rise of the price of fossil energy and by the internalization of associated social costs such as carbon emissions. Therefore we assume that in the medium to long-term competitiveness is achieved at a level of **5-7 cents€/kWh** for dispatchable mid-load power.

Today, several scenarios exist describing the potential deployment of CSP systems. A typical example is the Athene Study (www.dlr.de/socrates) that uses a scenario technique to quantify the word-wide deployment of CSP through 2025 (see Figure 1-1). Based on this analysis and taking into account learning and scaling effects, the overall investment cost and the average levelized electricity cost are estimated. This approach predicts a cost reduction down to 5 cents/kWh at a total installed capacity of 40 GW achieved between 2020 and 2025 (see **Figure 1-2**). The European Union has adopted the potential of this technology and currently supports the implementation of three pilot solar thermal power plants in Europe (PS10, ANDASOL, SOLAR TRES).

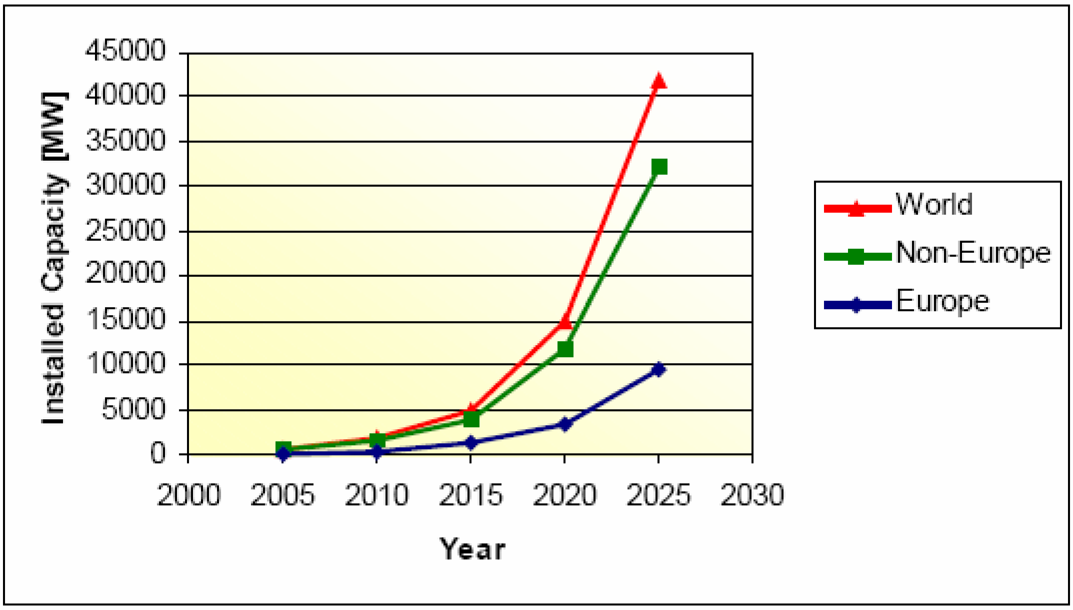


Figure 1-1: Athene scenario on the deployment of concentrated solar power systems (www.dlr.de/sokrates)

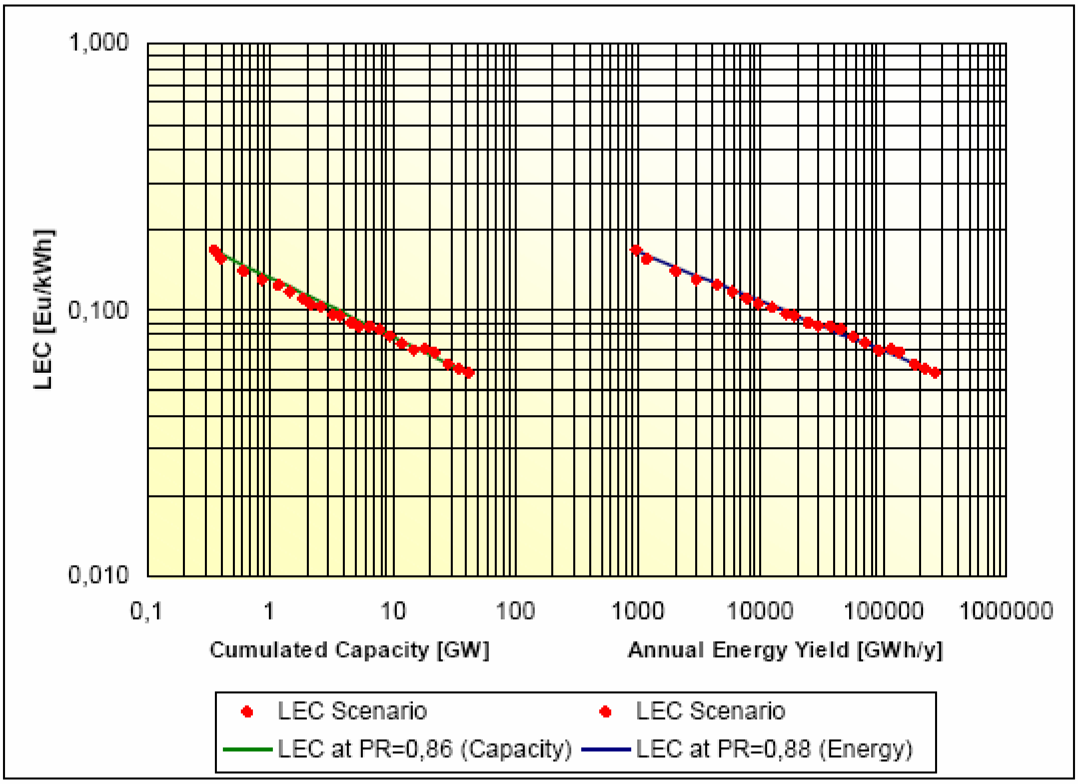


Figure 1-2 Athene scenario of the reduction of LEC predicted by the learning curve approach (see www.dlr.de/sokrates)

While scenario approaches estimate cost reduction potential and the total market incentives needed to achieve full compositeness with conventional choices, they do not help to identify specific innovations that may enable these reductions. Other recent cost reduction studies [1] have already pointed out that approximately half of the cost reduction potential for CSP can be attributed to scale-up to larger plant sizes and volume production effects, whereas the other half is attributed to technology R&D efforts.
The focus of this document is to show the essential technology innovations that may contribute significantly to the R&D-driven cost-reduction potential.

Three **major objectives** of the proposed ECOSTAR co-ordinating action are followed:

- to **identify the potential European technical innovations** with the highest impact on CSP-cost reduction.
- **to focus the European research activities and the national research programs** of the partners involved on **common goals and priorities**.
- and to **broaden the basis** of **industrial and research excellence,** capable to solve the multidisciplinary CSP specific problems.

In this context we understand the word “innovation” as something that is new compared to the current status of technology. Many of the considered innovations have been subject of R&D projects in the past, and due to the limited resources in the project, we have only included those where sufficient information on potential performance and costs are available from previous investigations. The list of innovations handled here is certainly not complete and should not discourage consideration of other advanced concepts. However, the major objective of this investigation is to show which of the ongoing work is most appropriate to achieve a significant cost reduction in CSP technologies. This is considered to be a pre-requisite to agree on R&D priorities in national and European programs.

1.2. Methodology

Today several CSP technologies (like parabolic troughs and central receiver using different heat transfer media) are at the phase of a first commercial deployment for bulk power production in Europe. In addition to those technologies, several others are also included in this investigation if they have had a successful proof-of-concept demonstration, have undergone comprehensive engineering studies, and if industry is promoting a commercial plant.
The approach is to analyze the impact on cost of different innovations applied to a reference system in order to identify those with the highest impacts. Cost and performance information of the reference systems are currently at a different level of maturity. Therefore, the evaluation will focus on the identification of the major cost reduction drivers for each of the considered reference systems and identify the impact of technical innovation approaches. This will lead to recommendation on R&D priorities as well as on recommendation on changes in the political framework needed to achieve a successful deployment. These findings should serve as input for the definition of future R&D and demonstration programs also support the adaptation of a political framework on the national and European level to accelerate commercial deployments.

The methodology for the cost study is depicted in Figure 1-3. The essential figure of merit is the levelized electricity cost (LEC) which is calculated according to a simplified IEA Method [2] using current euros (see the grey box next page, where the common assumptions for the financial parameters are listed). The goal of this study is the comparison of different technical innovations, therefore any project specific data (e.g. tax influences, or financing conditions) are neglected. The approach is kept simple, but it appears to be appropriate to perform the relative comparison necessary to quantify the impact of different innovations. For each reference system a detailed performance and cost model has been established in Microsoft Excel. The model uses common assumptions for the site[1], meteorological data [2] and load curve[3]. It calculates the annual electricity production hour by hour, taking into account the instant solar radiation, load curve, part load performance of all components (depending on load fraction and ambient temperature), operation of thermal energy storage, and parasitic energy requirements. The reference size of all systems is assumed to be 50 MW_{el} net.

[1] Seville, Spain 5.9 ° W, 37.2° N, 20 m above sea level, land costs 2,000,000 €/km²
[2] Seville, Spain, hourly data of direct normal insolation and ambient temperature from measurements; DNI 2014 kWh/m²a ;average Temp 19,5C°, Min = 4,1°C, Max = 41,4°C
[3] Free-load operation or in hybrid operation 100% load between 9:00 a.m. and 11 p.m. every day, average availability of 96% to account for forced and scheduled outages resulting in a capacity factor of 55%

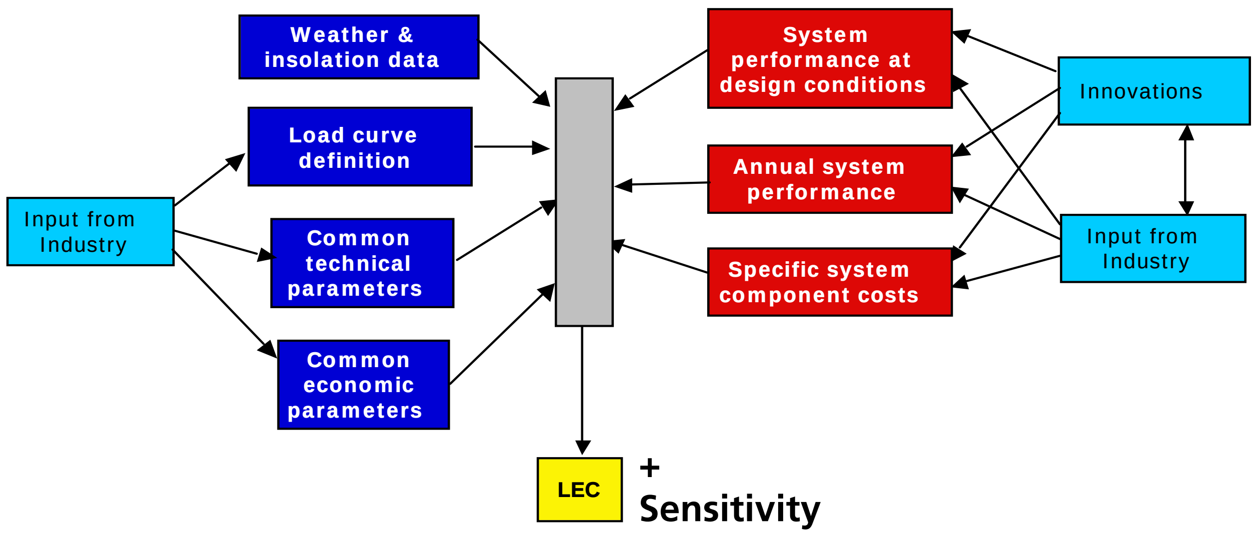


Figure 1-3: Methodology for the cost studies.

Definition of "Levelized Electricity Costs" (LEC)

$$LEC = \frac{crf \cdot K_{invest} + K_{O\&M} + K_{fuel}}{E_{net}}$$

with

$$crf = \frac{k_d (1 + k_d)^n}{(1 + k_d)^n - 1} + k_{insurance}$$ = **9,88%**

k_d real debt interest rate = **8%**

$k_{insurance}$ annual insurance rate = **1%**

n depreciation period in years = **30 years**

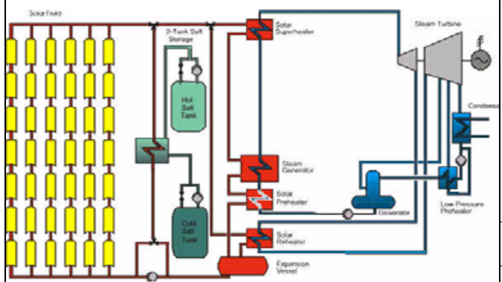
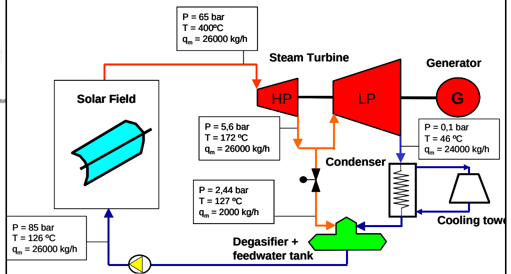
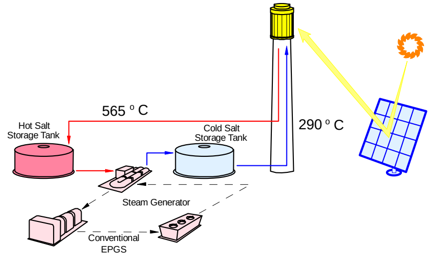
K_{invest} total investment of the plant

$K_{O\&M}$ annual operation and maintenance costs

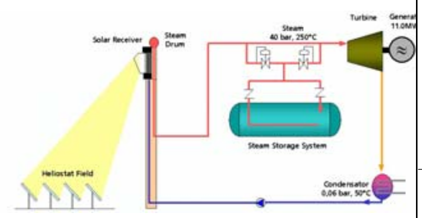
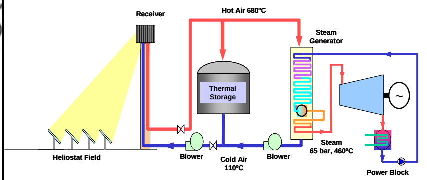
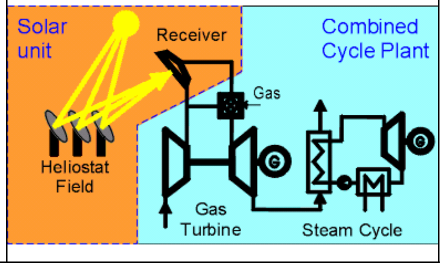
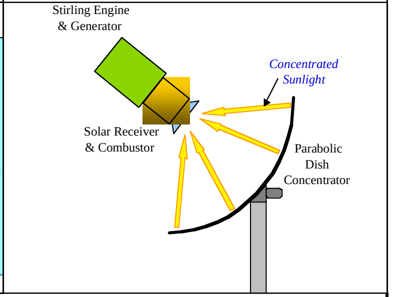
K_{Fuel} annual fuel costs

E_{net} annual net electricity

Seven different CSP technologies are considered in this study:

Technology	Parabolic trough / HTF	Parabolic trough DSG[4]	Molten salt Central receiver system
			
Technical design parameter:			
Collector	Parabolic trough	Parabolic trough	Heliostat field
Receiver	Linear receiver (tubes)	Linear receiver (tubes)	Molten salt receiver
Storage system	2-tank-molten-salt storage	No storage system available up to date	2-tank-molten-salt storage
Cycle	Rankine steam cycle	Rankine steam cycle	Rankine cycle
Planed / built power size			
	50 MW Andasol I & II, under preparation, Spain	4.7 MW INDITEP study	Solar Tres (17MW), planed, Spain
Maturity	Several commercial units up to 80 MW_e are in operation in southern USA	Single row experimental plant in Spain	Solar 2 (11 MW) experimental plant in California in the 1990ies
Temperature	393°C	411°C	565°C
Size of the reference system	50 MW_e	10 × 4.7 MW_e	3 × 17 MW_e
Solar capacity factor	29 %	22 %	33 %
LEC for a single ECOSTAR reference system, solar-only			
	0.172 €/kWh_e	0.187 €/kWh_e	0.183 €/kWh_e
LEC for power plant park consisting of several reference systems with total capacity of 50 MW, solar-only			
	0.172 €/kWh_e	0.162 €/kWh_e	0.155 €/kWh_e

[4] The linear Fresnel collector has been considered as innovation fort he parabolic trough DSG system in the subsequent analysis.

Technology	Saturated steam central receiver system	Atmospheric air central receiver system	Pressurized air central receiver system	Dish engine System
				
Technical design parameter:				
Collector	Heliostat field	Heliostat field	Heliostat field	Parabolic dish
Receiver	Saturated steam receiver	Volumetric atmospheric air-cooled receiver	Pressurized air receiver	Cavity receiver with tube bundle
Storage system	Water/steam buffer storage	Ceramic thermocline thermal storage	No storage system available up to date	No storage system available up to date
Cycle	Rankine cycle	Rankine cycle	Combined cycle	Stirling engine
Planed / built power size				
	PS 10 (11MW), under construction, Spain	PS 10 conceptual design study	Solgate study 14.6 MW_e	22 kW_e
Maturity	Several experimental plants up to 2 MW_{th} have been tested	2.5 MW_{th} experimental plant tested in Spain in 1993	2 × 200 kW_e under construction in Italy	About 30 units up to 25 kW_e are in operation at different sites
Temperature	250°C	750°C	800°C	800°C
Size of the reference system	5 × 11 MW_e	10 × 4.7 MW_e	4 × 14.6 MW_e	2907 × 25 kW_e
Solar capacity factor	26%	33 %	11 % (55%)[5]	22%
LEC for a single ECOSTAR reference system, solar-only				
	0.241 €/kWh_e	0.234 €/kWh_e	0.147 €/kWh_e (0.1 €/kWh_e)	0.281 €/kWh_e
LEC for a power plant park consisting of several reference systems with total capacity of 50 MW, solar-only				
	0.169 €/kWh_e	0.179 €/kWh_e	0.139 €/kWh_e (0.082 €/kWh_e)	0.193 €/kWh_e

[5] Values in brackets are for hybrid operation

Classes of innovations

The innovations considered within this study may be divided into several groups:

- Scale up of of plant size to 50 MW_{el}: This measure is required because only the parabolic trough HTF system has been demonstrated at a 50 MWe size. All other technologies considered here are planned at a scale of 15 MWe or smaller for initial commercial demonstrations.
  For these technologies, it is assumed that several smaller plants are co-located at one site to reach the 50 MWe reference size and provide a common basis for computing O&M costs. Increasing plant scale to 50 MWe for those systems would provide a significant efficiency increase and cost reduction.
- Modification of structures, application of new materials and simplification of the concentrator system are measures of the second group of innovations.
- Integration of thermal storage for several full load hours, together with new storage materials and advanced charging/discharging concepts allow for increased solar electricity production without changing the power block size. Provided that the storage is sufficiently inexpensive, this would lower the LEC, and additionally increase the dispatch ability of the electricity generation.
- Further development of the cycle with increased temperatures, or additional superheating for the CRS saturated steam plant are considered. These measures provide higher efficiencies and solar fractions.
- For all CSP reference systems the most promising innovations are combined (as far as possible) and the cost reduction potential for this combination of selected measures has been calculated.

One has to keep in mind that the innovations have different probabilities of success and are in different stages of development; some of are already conceptually proven and some are only a concept. This uncertainty is addressed by providing optimistic and pessimistic bounds on the input data for the performance and cost model, resulting in appropriate bounds for the LEC values and cost reduction percentages presented here.

1.3. Summary of findings

Today's costs and cost reduction potential

Many of the systems considered here are planned for commercial deployment in Spain, which recently enacted an incentive of around **21 cents€/kWh** for solar thermal electricity. The most mature technology today is the parabolic trough system that uses thermal oil as a heat transfer medium. Several **50 MW_{el}** units using thermal energy storage based on molten salt are currently planned in Spain. The present ECOSTAR evaluation estimates levelized electricity cost of **17-18 cents€/kWh** for these initial systems, assuming a load demand between 9:00 a.m. and 11:00 p.m. These cost estimates may deviate from electricity revenues needed for the first commercial plants in Spain because they were evaluated using a simplified methodology including the financing assumptions recommended by the IEA for comparative studies like this. The other technologies analyzed are currently planned in significantly smaller pilot scale of up to **15 MW_{el}**. The LEC is significantly higher for these small systems ranging from **19 to 28 cents/kWh**. Assuming that several of the smaller systems are built at the same site to achieve a power level of 50 MW and take benefit of a similar O&M effort as the larger plants, LEC estimates of all of the systems also range between 15 and 20 cents/kWh. The systems achieve a **solar capacity factor of up to 30%** under these conditions (depending on the availability of storage). One significant exception is the integration of solar energy into a gas turbine /

combined cycle, which at the current status of technology can only provide a solar capacity factor of 11% and needs significant fossil fuel (20% -25 % annual solar share depending on load curve) but offers **LEC of below 9 cents/kWh for the hybrid operation**[6] (equivalent to 14 cents/kWh for the solar LEC). Due to the low specific investment cost of the gas turbine / combined cycle together with a high efficiency, the system is specifically attractive for hybrid operation. Further development of the receiver technology can increase the solar share significantly in the future.

Since the absolute cost data for each of the reference systems are relatively close and are based on a different level of maturity, **choosing technologies for R&D prioritization** (e.g. troughs vs. towers) **doesn't appear feasible**. This competition between technologies will be left to industrial entrepreneurship and market forces. However, the evaluation has identified the major cost reduction drivers for each of the considered reference systems and has identified the impact of technical innovation approaches.

For all systems considered technical innovations were identified and translated into component cost and performance estimates to calculate the LEC. For example the utilisation of thin glass mirrors in parabolic trough collectors impacts the following:

- the mean reflectivity is left unchanged at 0.88 / increases to 0.89,
- the specific investment costs are reduced to 95% / 90% of the reference value,
- the O&M equipment cost percentage is increased to 1.1% / left unchanged at 1.0%.

The first of the above mentioned parameter values is the pessimistic estimate and the second one is the optimistic one. Using these boundary values within the annual calculation model results in the boundary values for the LEC reduction shown in Figure 1-4.

The most promising options were combined to evaluate the overall cost reduction potential. Based on the limited number of approaches suggested in the scope of this study, **cost reductions of 25 - 35%** due to technical innovations and scaling up to 50 MW_e are feasible for most of the technologies. These figures do not include effects of **volume production** or **scaling of the power size of the plants beyond 50 MW unit size, which** would result in further cost reductions.

For parabolic trough technology the Sargent & Lundy study [1] estimated a cost reduction of 14 % from larger power blocks (400 MW) and 17% by volume production effects when installing 600 MW per year. Assuming similar figures also for the other technologies, an **overall cost reduction of 55 – 65%** can be estimated in the next 15 years. Figure 1-5 illustrates this accumulated potential for the parabolic trough / HTF system, but very similar figures appear feasible for the other six systems investigated here.

[6] At a fuel price of 15 €/MWh

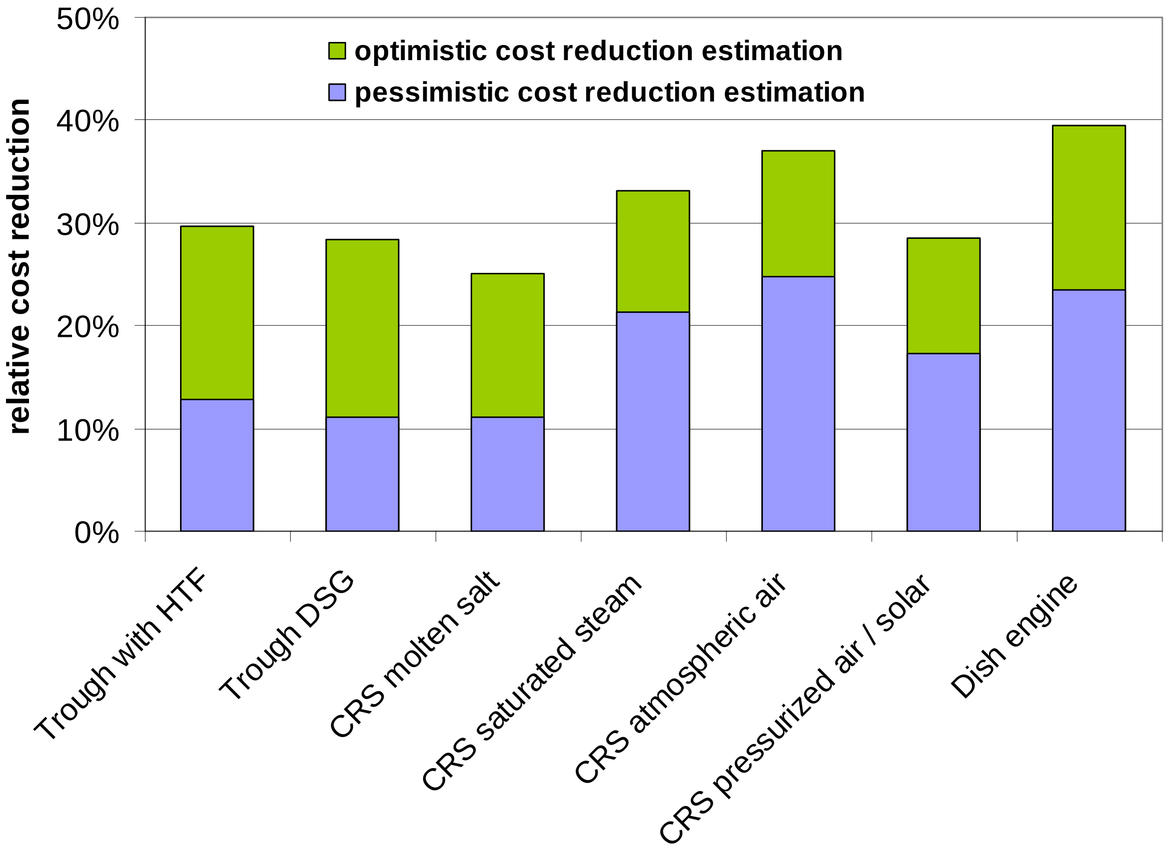


Figure 1-4: Innovation driven cost reduction potential for the 7 CSP technologies investigated in this study based on the LEC for the 50 MW_e reference system and assuming a combination of selected innovations for each system.

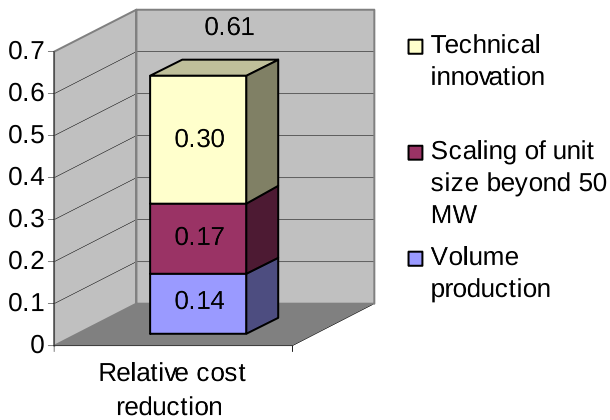


Figure 1-5: Potential relative reduction of LEC by innovations, scaling and series production through 2020 for the parabolic trough/HTF system compared to today's LEC

This would lead to levelized cost of electricity in **Southern Spain of around 6.7 cents/kWh** and down to **5 cents/kWh in high solar resource areas** (see Figure 1-6) like those at the southern shore of the Mediterranean sea and would represent competitive cost for mid-load power (without CO_2 emissions).

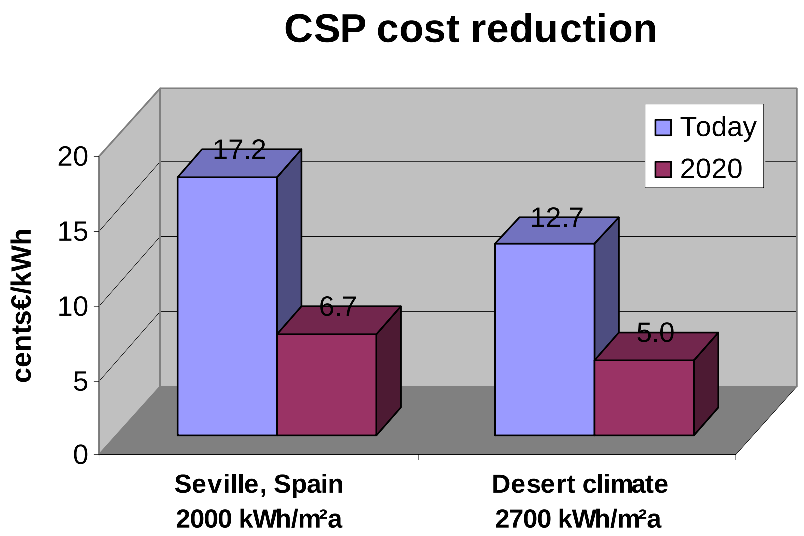


Figure 1-6: Predicted LEC today and in 2020 in cents/kWh for CSP technology for two different climate conditions. Shown for the parabolic trough / HTF system.

1.4. Research Priorities

The various innovations aspects have different impact for on the LEC reduction of the 7 systems investigated. The **innovation potential** with the highest impact on CSP-cost reduction is presented for each of the technologies in the following table

Technology	Priority A	ΔLEC	Priority B	ΔLEC	Priority C	ΔLEC
Trough using oil	concentrator structure and assembly	7-11%	Low cost storage system advanced reflectors and absorber	3-6 % 2-6%	increase HTF Temp reduce parasitics	1 - 3 % 2 – 3 %
Trough DSG	scale increased to 50 MW system Concentrator structure, and assembly	14 % 7-11%	Advanced Storage advanced reflectors and absorber	3-6% 2-6%	Increase HTF Temp reduce parasitics	1 - 3 % 2 – 3 %
SCR Salt	scale increased to 50 MW heliostat size, structure,	3 -11% 7 -11%	Advanced mirrors	2 -6%	advanced storage	0 -1 %
SCR Steam	scale increased to 50 MW heliostat size, structure,	6-11% 7 -11%	superheated steam advanced storage	6 -10% 5-7%	advanced mirrors	2 -6%
SCR Atmosph. Air	scale increased to 50 MW heliostat size, structure,	8 -14% 7 -11%	advanced storage increased receiver performance	4-9% 3-7%	advanced mirrors	2 -6%
SCR Hybrid GT	Heliostat size, structure, Include Thermal Storage	7 -11 % 7 –10%	scale increased to 50 MW	3- 9%	advanced mirrors increased rec. performance.	2 -6% 1- 2%
Dish	mass production for 50 MW	38 %	improve availab and red. O&M. Brayton instead of Stirling Increased unit size	8-11% 6-12% 5-9%	increased engine eff. reduced engine cost advanced mirror and tracking	2-6% 2-6% 0-1%

Summarizing the detailed findings for the individual systems we may see that improvements in the **concentrator** performance and cost most drastically impact the LEC figures. Since the concentrator is a modular component, development of prototypes and benchmarks of these innovations in real solar power plant operation condition in parallel with state of the art technology is a straight forward strategy. New reflector materials should be low cost and have the following traits:

- good outdoor durability,
- high solar reflectivity (>92%) for wave lengths within the range: 300 nm - 2500 nm,
- good mechanical resistance to withstand periodical washing,
- low soiling coefficient (<0.15%, similar to that of the back-silvered glass mirrors).

The supporting structure of the concentrators also needs improvement. New structures should fulfil the following requisites:

- lower weight
- higher stiffness
- More accurate tracking
- Simplified assembly

Scaling to larger power cycles is an essential step for all technologies except for parabolic trough systems using thermal oil, which have already gone through the scaling in the nine SEFS installations in California starting at 14 MWe and ending at 80 MWe. Scaling reduces unit investment cost, unit operation and maintenance costs, and increases performance. The integration into larger cycles specifically for power tower systems means a significant challenge due to the less modular design. Here the development of low-risk scale-up concepts is still lacking.

Storage Systems are a second key factor for cost reduction of solar power plants. Development needs are very much linked to the specific requirements of the systems in terms of the used heat transfer medium and the required temperature. In general storage development needs several scale-up steps generally linked to an extended development time before a market acceptance can be reached. Requirements for storage systems are

- Efficient in terms of energy and exergy losses
- Low cost
- Long service life
- Low parasitic power requirements

Especially challenging is the development of storage systems for high pressure steam and pressurized, high temperature air that would lead to a significant drop in electricity costs.
Higher temperatures also lead in many cases to higher system performance. The current status of receiver technology however, does not exploit the full performance potential. Significant improvements in the performance of high temperature receivers are possible, whereas the room for performance improvements in the temperature range below 400° is relatively small (cost improvements are possible).

1.5. How to reach the CSP Vision

The detailed analysis has identified a number of innovations most relevant for cost reduction. In order to transfer this knowledge first into products, then into a continuous deployment of CSP technology a number of key issues must be addressed:

Increasing RTD efforts

The amount of RTD funds by the European Union dedicated to CSP was small compared to other technologies like wind, photovoltaics and biomass. However, they have been sufficient to support a new start-up of CSP technology in Europe (specifically in Spain and Italy). Several hundred MWs of installed capacity appear likely to be installed by 2010. If the predicted cost reductions triggered by technical innovations shall play off its full potential in the next 15 years a significant increase in RTD efforts is required to be introduced in the 7th Framework Programme. This money appears to be well invested in a low cost solar technology providing dispatch-able bulk electricity.

Alignment of RTD strategies and goals

ECOSTAR aims to initialize a much stronger long-term European integration effect than can be achieved by co-operation on a project-by-project basis. It will initiate the process to agree on common goals and priorities and utilize national and European resources most effectively to achieve them. All European Research centers involved in ECOSTAR manage a significant institutional (or sometimes even national) budget for CSP research. A joint European roadmap shall be the starting point to adjust their individual program goals and priorities in order to achieve the highest impact with their limited resources. This will be the basis to implement the existing European facilities of various powers and concentration factors, the existing tools and human resources most efficiently in future projects and to streamline the national development activities by setting common priorities and goals. One important result is the formation of the SOLLAB alliance formed by CIEMAT, CNRS, DLR and ETH to reach this goal. It is recommended to support the extension of such an R&D platform as a European network of excellence.

Involving further excellence

Further expertise is needed. Until now only a small number of companies with specific expertise and a variety of research institutions were involved in European R&D projects in this field. Further expertise is required:

- Large companies capable and used to lead EPC contracts of several hundred Million Euro from the power sector could bring a better market knowledge and cover the question of integration of the solar system with the power cycle more thoroughly,
- Companies specialized in glass, reflectors, light weight structures, drives, outdoor plastic etc. could provide expertise in concentrators,
- Chemical industry could support the development of improved HTF or storage media,
- Large construction companies capable of designing and building storage containers which are able to handle and transport hot fluids,
- Companies specialized in mass production and logistics (like car manufacturers) could optimize the production process and minimize manufacturing cost,
- Technical supervising companies to achieve a high quality control to reduce risks specifically in the scaling process.

Building a global market

CSP is currently emerging in many countries of the World; in Spain the situation is one of the most far developed. **A key to success is to build a sustainable market situation**. In many of the countries, the progress is slow in part due to non-technical barriers. In order to generate a global market, it is important to take the lessons learned in the countries where CSP deployment is successful and transfer them to other countries. Such a market would have faster growth, would attract larger global companies, and would lead to costs increasingly competitive with conventional sources. The CSP global market initiative (GMI; www.solarpaces.org/gmi.htm) is an essential step that needs support of the European Union.

Setting the political framework

- CSP is inadequately considered in most European renewable electricity incentive schemes. Countries like Portugal, Greece Malta and Italy having a significant solar resource may consider opening their incentive schemes to CSP technologies.
- Consider opening the European market for the import of solar electric from Northern Africa. Higher solar resource levels may over-compensate the additional transport cost and the deployment of the technology would help to support the political stability in this region.
- Hybrid operation of CSP systems is of high benefit for both the cost of the solar electricity as well as for the stability of the electrical grid. The legal frameworks should be more flexible to allow this option.
- Scaling up CSP to larger power block sizes is an essential step to reduce electricity costs. Incentive schemes should not limit the upper power level to fully exploit the cost reduction potential.

2. Organisation of this document

This document presents a technical Roadmap for Concentrating Solar Thermal, i.e. assessing and prioritizing research, development and demonstration activities to reduce the cost of solar electricity efficiently. It is structured in 8 chapters:

Chapter 3 **the value of CSP for bulk electricity production** briefly highlights the potential, benefits and constraints of CSP compared to other renewable electricity options.

Chapter 4 **the sensitivity** of cost of solar electricity on the most essential parameters like site and meteo data, the load curve, the investment cost the size of the plant etc are presented in a generic approach.

Chapter 5 **the reference systems** give an overview on 7 different technical concepts of CSP systems which are currently promoted in the market. It describes the technical status, give estimates on today's cost for the first 50 MW systems.

Chapter 6 **technical innovations analyzed** give an overview of the considered technical innovations in the field of concentrators, storage systems and receivers/absorbers and cycles, including cost, performance potential uncertainties and development risk.

Chapter 7 **Impact of innovations on the reference systems** presents the results of cost studies performed for the respective innovations for each reference systems.

Chapter 8 **Conclusion and recommendations** cover conclusions on R&D and demonstration priorities for each of the technologies and nominates further expertise needed. It also points to constraints in the political framework that limits the current deployment.

3. The value of CSP for bulk electricity production

Concentrating solar power systems are similar to small to medium size conventional power plants and benefit therefore in a variety of ways.
This comprehends:

1. **the potential capacity of CSP in Europe**
   The potential of CSP in Europe (EU-15) is estimated to be above 2000 TWh/years mainly in Spain, Italy and Greece including Mediterranean islands. This potential figure has only considered unused, unprotected flat land area with no hydrographical or geomorphologic exclusion criteria with a direct radiation level above 1800 kWh/m²a. When including the import of solar electricity form northern Africa, the potential is considered almost infinite (see Figure 3-1). Comparing this to other renewable energy option (see Table 3-1) even without import this is a significant potential to provide dispatch-able renewable bulk electricity to the European grid.

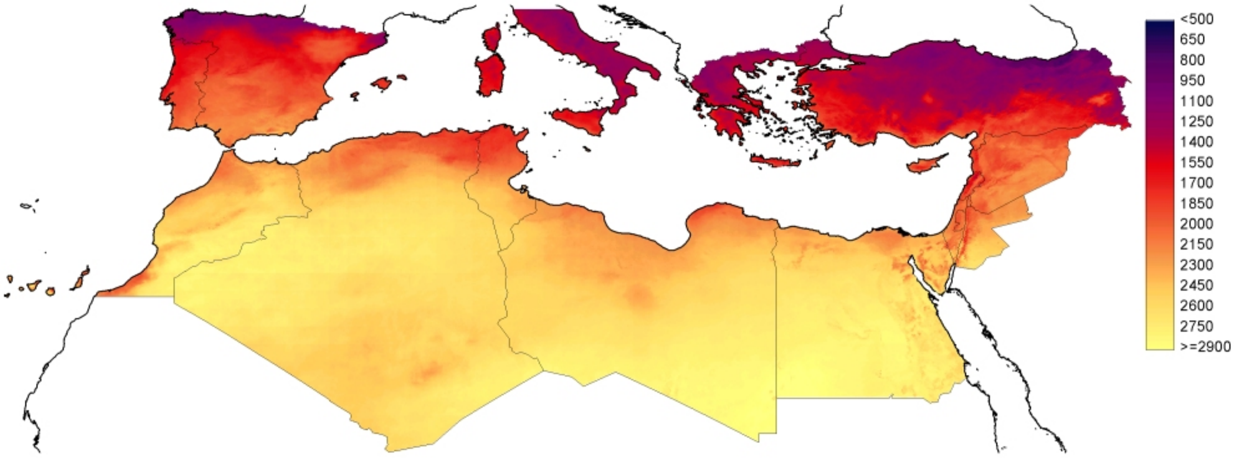


Figure 3-1: Direct Normal Radiation potential for the Mediterranean Area in 2002 (derived form satellite data) [3].

2. **the connection to the electric grid**
   CSP systems consist of a conventional power cycle (in most cases a Rankine cycle) of a power size 10 – 100 MW_{el}. Grid connection is performed on a high voltage level using the same equipment as conventional power pants. The availability of a power line with sufficient capacity is an essential criterion for the site selection (as is the availability of low-cost land and a high radiation level). To minimize O&M costs it appears beneficial to locate several power blocks next to each other. In Kramer Junction in California 150 MW_{el} of installed capacity of parabolic trough power plants in five blocks are operated in one joint area. These plants proved high availability of more than 98% during sunshine hours for many years. The area needed for CSP installations is approximately 8-12 m²/MWh of solar electric power output.

Table 3-1: Assured technical potentials of renewable energy sources in Western Europe [4].

Renewable Sources	**Electricity generation TWh/a**	**Heat production PJ/a**	**Primary energy PJ/a**	**Used in 2001 %**	**Remarks**
Hydropower	640		2 270	79	New plants only on regulated rivers; contains reactivation and modernization of existing plants
Wind energy	1 580		5 680	1.8	Restricted potentials onshore 630 TWh/a., offshore 950 TWh/a. considering acceptance as high and ecological interaction as low as possible
Photovoltaic	585		2 105	0.03	2 300 km^2 module area assumed = 25% of suitable roofs and 100% of suitable facades (1000 km^2)
Biomass residues	185	2 350	3 350	52	Residues from forestry, agriculture and organic fraction of municipal waste; for energy plantations present excess agricultural area in EU-15 (9 Mill. ha) assumed; 50% use in cogeneration plants, 50% direct heat production, no fuel production assumed
Energy crops and short rotation forestry	85	1 050	1 500		
Thermal collectors		6 570	7 300	0.2	4 000 km^2 collector area assumed = 75% of suitable roofs; contains also large collector fields with seasonal heat storage
Geothermal energy	350	5 000	9 155	1.4	only known resources (lowest value of a variety of estimates)
Solar thermal power plants	< 2 000		7 200	0	suitable sites for 100-200 MW solar thermal power plants in Southern Europe (Spain, Italy, Greece, including islands)
Total RES-potential	**5 415**	**14 970**	**38 560**	**12**	
Consumption 2001	2 800	20 000	62 500		
Share of RES-potential (%)	**193**	**75**	**62**		

3. **the need for cooling water**
   Rankine cycles used in CSP plants may be operated with dry cooling to minimize the use of water. However, the performance is reduced (approx. 6 % less electricity production compared to wet cooling), which results in a proportional increase of the LEC. The California CSP plants need approximately 3.4 m^3/MWh [5] of raw water for wet cooling purposes. To optimize the economics, actual project developments are seeking for sites where sufficient water is available for wet cooling. However, in case of a broad deployment of CSP technology, dry cooling may become inevitable in many cases, due to the lack of appropriate sites.

4. **the capability to provide power on demand**
   Although the sun is an intermittent source of energy, CSP systems offer the advantage to run the plant continuously at a predefined load. This can be achieved in principle by two approaches:
   a) the use of a thermal energy storage
      Thermal energy storage systems are storing the thermal heat collected by the solar field. A typical storage concept consists of two storage tanks filled with a liquid storage medium which are on a different temperature level. When charging the

storage, the medium is pumped from the “cold” to the “hot“ tank being heated up (directly or indirectly) using the collected solar heat. When discharging the storage the medium is pumped from the “hot” to the “cold” tank extracting the heat in a steam generator that drives the power cycle. The capacity of the storage is normally designed for some full-load hours of the plant. Due to a large surface to volume ratio of these systems heat and exergetic losses can be kept below 5% of the thermal throughput. Storage systems help to let the plant always run under full-load conditions. This is an essential difference compared to other renewables like wind or PV. There is no need for short-term control energy back-up from the grid, like for wind power turbines. A wind gust or cloud may cut off the actual energy supplied by wind turbines or PV generator in seconds. The grid has to respond in this case. Short term control power which is needed to compensate for such situations costs up to 9.5 cents€/kWh [6]. In case of the solar thermal energy storage, it is clear already hours ahead when the plant has to stop its energy supply. Combined with an appropriate weather forecast, a 24 to 48 h prediction of the solar capacity appears to be feasible.

Compared to the storage of electricity, heat storage offers some significant benefits. First, its specific costs and efficiencies can be very attractive (specific investment costs of 10–30 €/kWh$_{th}$ resulting in 25-75 €/kWh$_{el}$ of storage capacity and efficiencies of >95%[7]). Second, unlike electricity storage system, thermal energy storage cost does not necessarily increase the specific electricity generation cost of the plant. This aspect needs some more explanation: When electrical energy storage is added to an existing power generation system, it will be capable to shift the power according to the demand. This additional flexibility has to be paid by an additional investment in the storage which increases the specific cost of the electricity. The situation is different for CSP using a thermal storage system. The power conversion unit in a CSP system without storage runs about 1800-2500 full-load hours due to the limited sunshine hours. The addition of a solar thermal storage to a solar collector field, result in the fact that the power conversion can be reduced in its nominal power capacity (which saves costs), and in parallel its full-load operation hours are extended. If the investment in the storage is less than the cost saving in the smaller power block, the specific electricity generation costs are reduced[8].

We have to keep in mind that thermal energy storage systems are designed to shift energy for some hours (e.g. from day time to evening). It can not compensate the seasonal difference of the solar input which results from a changing sunshine duration from summer to winter. Thus, solar plants with thermal energy storage provide different capacity factors in summer and winter. In Figure 3-2 this is shown for a parabolic trough power plant with 7 hour of equivalent full load capacity.

[7] To compare: pump storage plants have specific investment costs of more than 70 €/kWh$_{el}$ of storage capacity and an efficiency below 80%;

[8] A thermal capacity equivalent to 6-7 h of full-load operation is needed to double the utilization factor of the power block, when operated without storage.

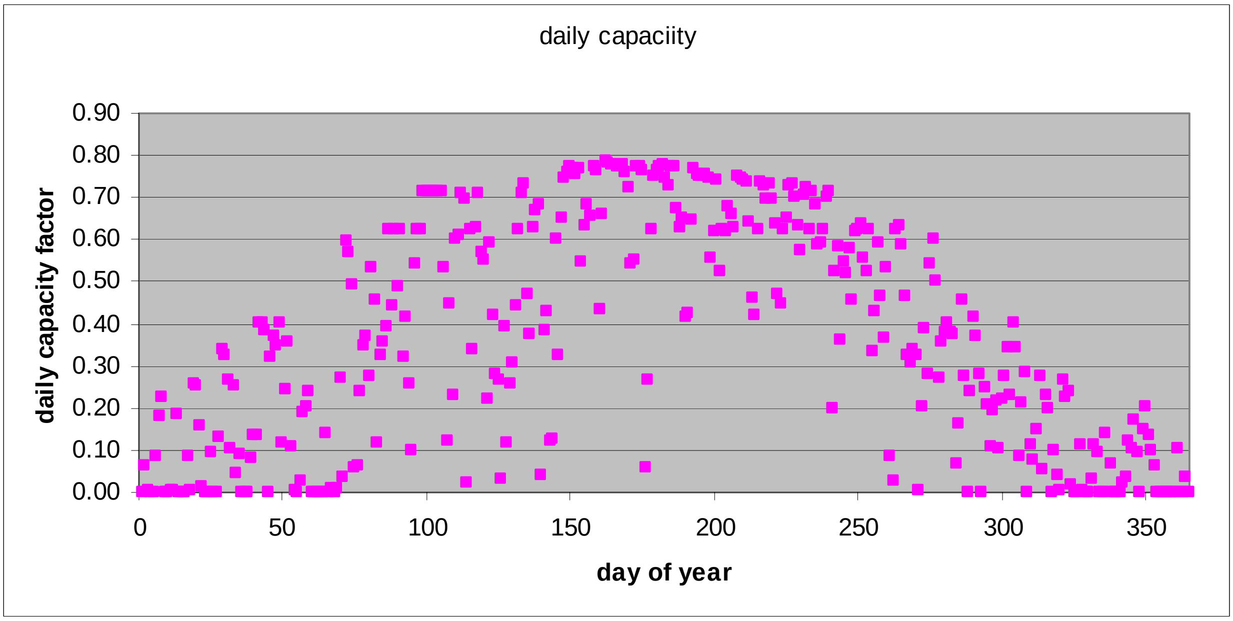


Figure 3-2: Distribution of daily capacity factors in solar-only operation[9] (annual 34.9%)

b) the use of fossil fuel to generate the heat
In addition to thermal energy storage, fossil fuel may be used to generate power. This approach is often referred to as "hybridization". In the case of a Rankine cycle the combination with thermal energy storage appears beneficial in order to avoid frequent start-ups of the fossil heater (steam generator). The use of fossil fuel in CSP systems offers two major benefits: first, it increases the capacity factor and could homogenise its change from summer to winter. At the current level of fuel prices, CSP investment cost and O&M costs, the hybrid operation will reduce the LEC compared to the solar-only one. The second argument is the avoidance of "shadow plant capacity". This becomes very obvious, when we reflect the situation of wind power as depicted in Figure 3-3. Due to the intermittent character of the wind, only a small fraction of the installed wind power capacity (3000 MW nominal in this Example) can "replace" existing fossil power cycle capacity. This situation would be different in CSP systems operated in hybrid conditions. Almost 100% of the capacity would be useful to replace existing capacity. The optimal capacity will depend on the individual situation, i.e. fuel price, prices of electricity as a function of time etc. so that no general statement could be taken. However, very high capacity factors (>60%) are not very cot effective, since the thermal to electric efficiency of the solar plants are smaller than those of modern large scale Combined Cycle power plants.

[9] Daily capacity factor of 0,5 would mean 12 hour of continuous full-load operation at that day

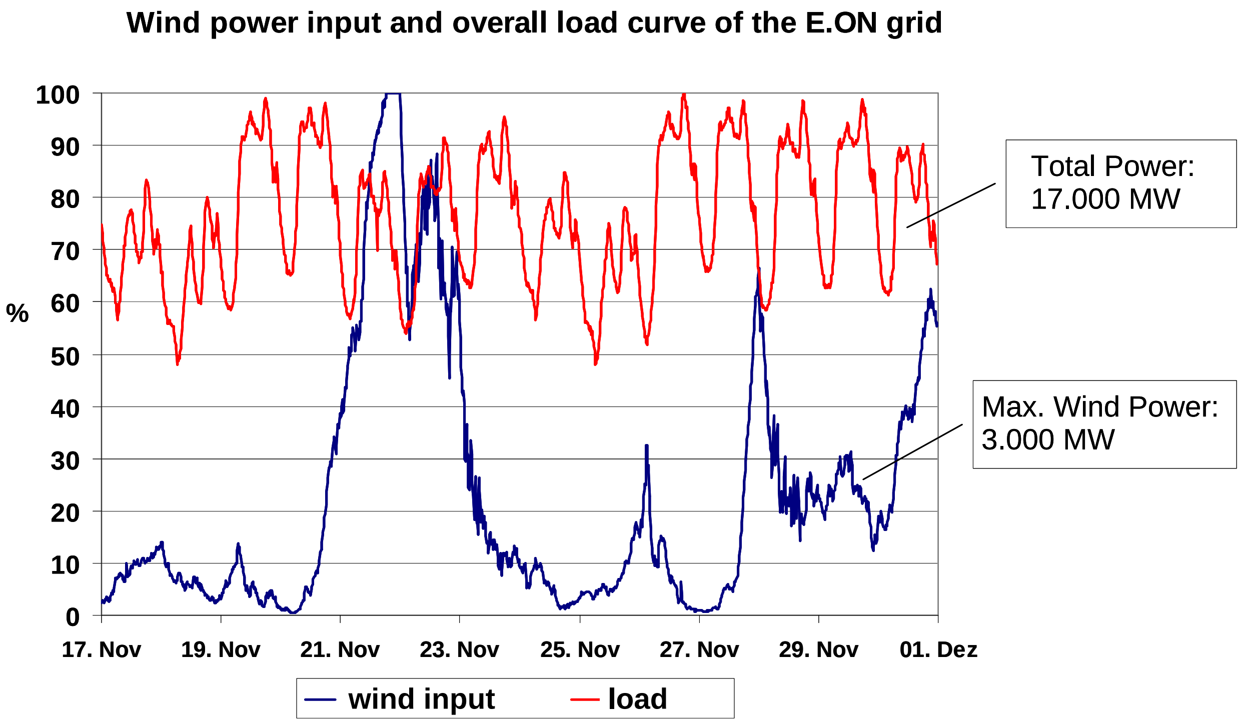


Figure 3-3 Example for the fluctuation of power supply from wind power in Germany compared to the overall load curve in the E.ON grid [7].

4. Sensitivity

Within several studies LEC costs are calculated to predict mid and long term values. Sargent & Lundy and SunLab published LEC costs [1], which are shown in Figure 4-1. The curves highlight cost reductions potentials for the tower and the trough technology. In this chapter, we want to point out the essential parameters that impact the absolute figures of these cost estimations.

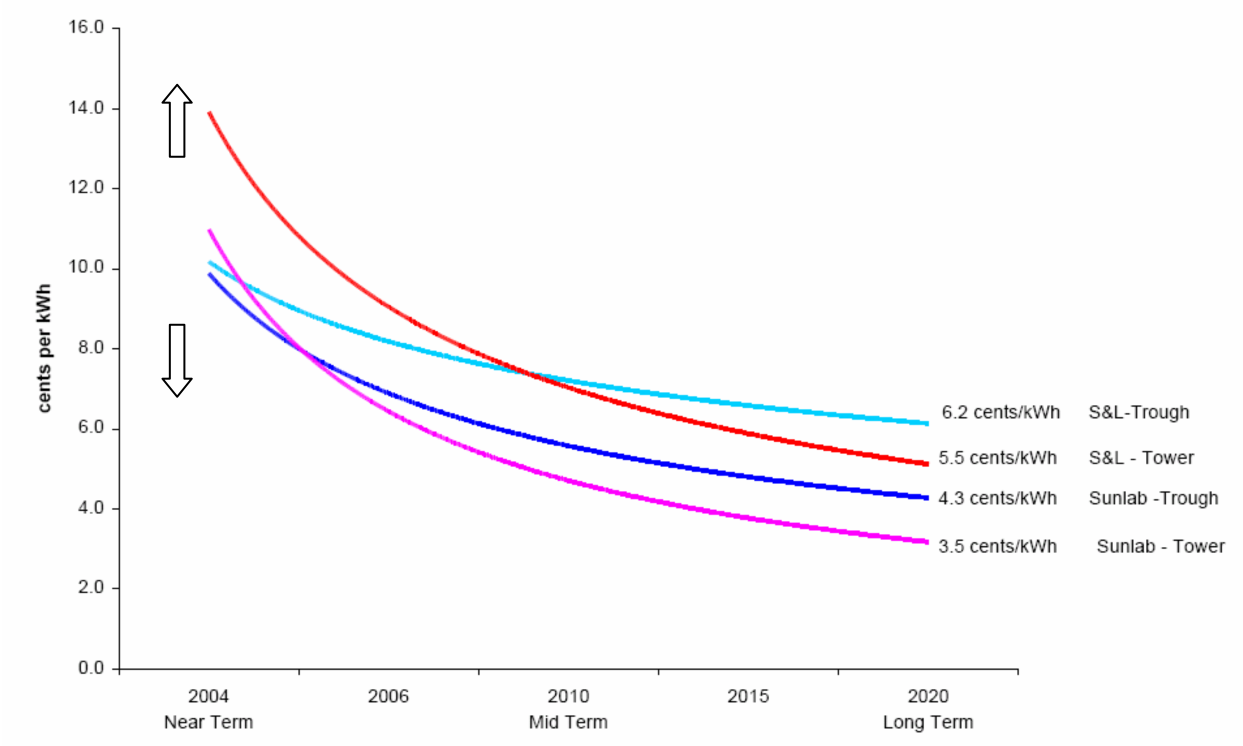


Figure 4-1: Sensitivity on LEC costs for different CSP systems calculated by Sargent & Lundy and Sunlab [1].

Within the ECOSTAR methodology a generic cost sensitivity analysis is performed on two levels as presented in Figure 4-2. On the first level, the general impact of the first level parameters (Investment cost, O&M costs, annual electricity production and fixed charge rate) impacting the LEC is investigated.

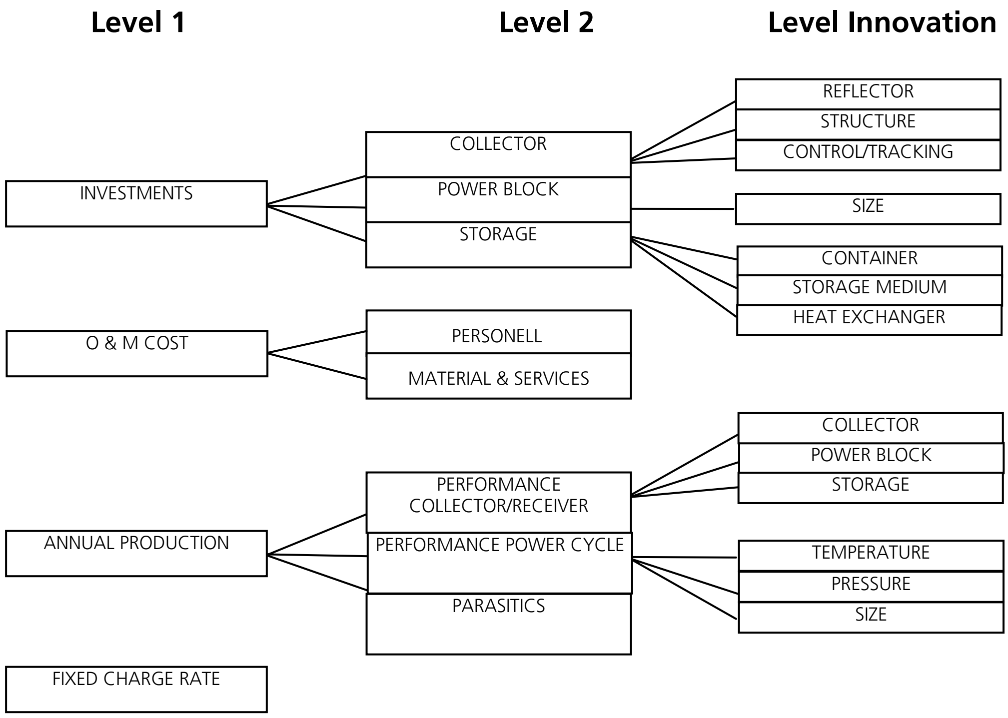


Figure 4-2: Impact of different levels of parameters on the LEC.

The impact of relative change in one of the four parameters on the change of the LEC is presented in Figure 4-3 for a typical solar-only plant with thermal storage compared to a small conventional 50 MW power cycle system in Figure 4-4.

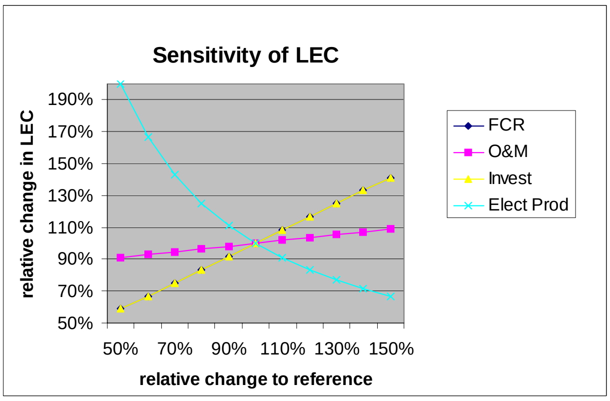


Figure 4-3: Sensitivity of fixed charge rate, investment cost, O&M cost and electricity production on the LEC of parabolic trough power plant using thermal oil as HTF.

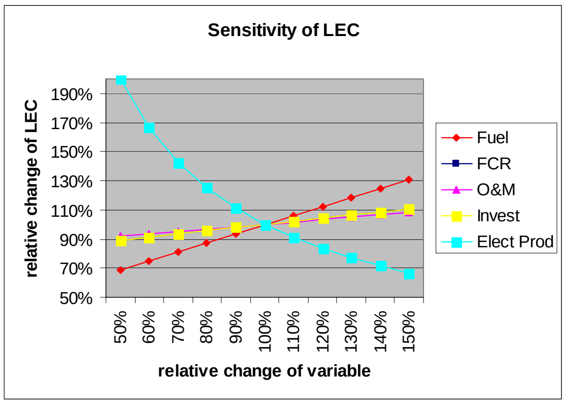


Figure 4-4: Sensitivity of fuel costs, fixed charge rate, investment cost, O&M cost and electricity production on the solar LEC for a 50 MW conventional power plant.

For the solar system the Fixed Charge rate, the annual electricity production and the investment cost have strong linear impact of the LEC. Essential consequences of this aspect is that relative cost reductions in investments play a more essential role than in conventional power cycles, where the fuel cost have the strongest impact. A reduction in the financing conditions has the same impact than in the investment costs itself. Since financing costs (FCR) are often associated with risk, risk management is an essential aspect for cost reduction for CSP systems. O&M cost are of minor importance, as long as there are not impacting directly the performance of the system. E.g. if the increase of the frequency of mirror washing would increase the annual performance by 1% it may cost of up to 10% of the O&M budget to result in a LEC reduction. An increase of the annual electricity production (e.g. by a performance increase or better solar radiation conditions) is the other essential factor that impacts the LEC. Site selection is therefore a very critical issue, since it impacts the available DNI strongly. In this study we have picked Seville as atypical site in Southern Spain with a Direct Normal irradiance of approximately 2000 kWh/m²a. The impact of the direct solar radiation resource on the LEC is very strong as can be seen in Figure 4-5. 2000 kWh/m²a represent a good south European site (like Seville in our study), 2300 kWh/m²a an excellent south European site; 2600 kWh/m²a a desert site, and 2900 kWh/ m²a is the upper limit of what can be found in the world.

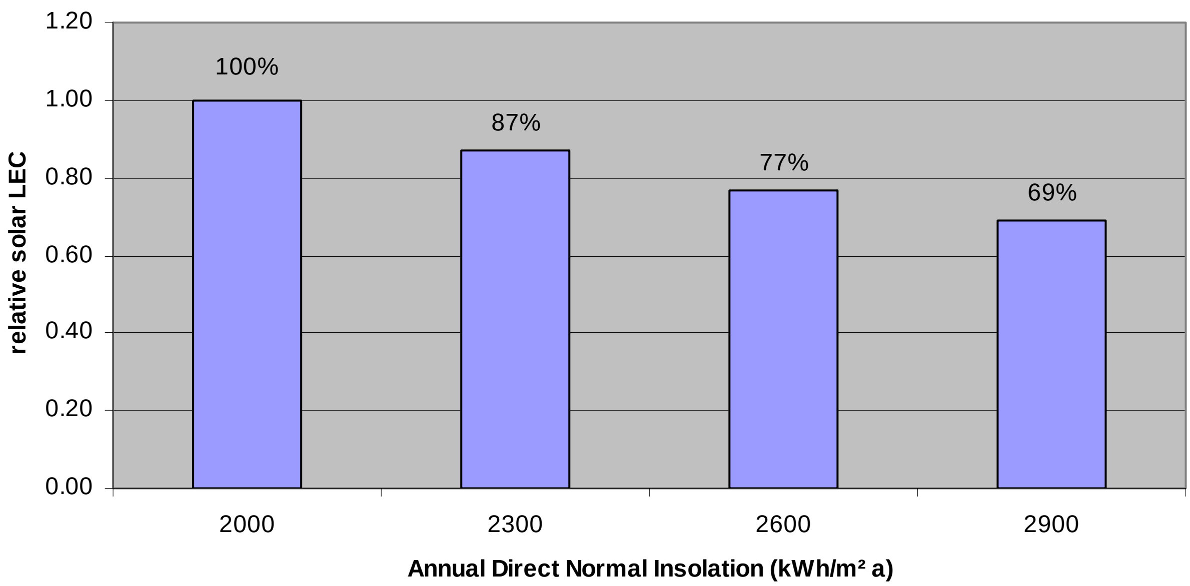


Figure 4-5: Dependency of solar LEC on DNI resource (free load, 6h storage).

If a thermal energy storage is used the LEC depends also on the load curve. In this case, the solar collector field is sized to provide not only the nominal power to the power block under design conditions but also to feed part of the energy to the thermal energy storage to be used after sun-set or in cloudy periods. When electricity revenues are independent of the time of day (like in many renewable incentive schemes) a large solar field and large storage yield to the lowest solar electricity cost. This is shown exemplary in Figure 4-6 for a parabolic trough system. If the revenues are changing with time (e.g. no revenues between 11:00 a.m. to 8 p.m., see Figure 4-7), than a smaller solar field size and a smaller storage are more economic. Limiting the revenue period of the plant may impact the cost of the average kWh by more than 10%.

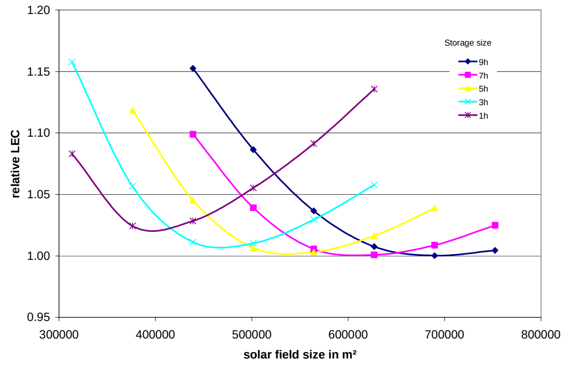


Figure 4-6: Relative LEC for solar-only operation of a parabolic trough plant with HTF as a function of the solar field and storage size (free load operating mode; base case: 6h storage, optimal field size).

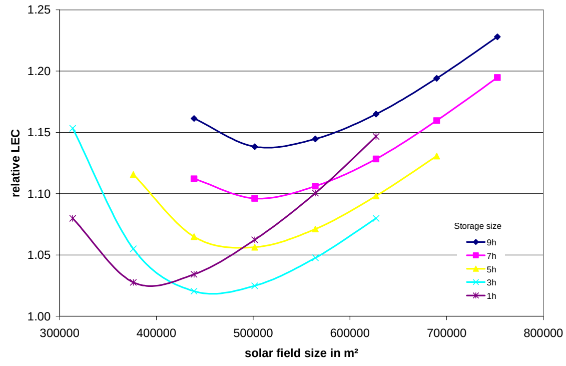


Figure 4-7: Relative LEC for solar-only operation of a parabolic trough plant with HTF as a function of the solar field and storage size (full load from 9 a.m. to 11 p.m.; base case: 6h storage, optimal field size).

On the second level of this sensitivity analysis, we want to investigate the impact of the different investment shares of the solar plant. This is presented for a solar-only system in Figure 4-8.
The solar field has the strongest impact, power block and storage smaller but similar and land cost and contingencies have minor impact. The figure makes clear that a reduction of solar collector cost alone (even if the cost could be cut by half e.g. by mass production) would not result by far in competitive power generation cost. Cost of the power block can be reduced by the scale-up to larger sizes, to reduce the specific investment cost. Storage also bears significant technical innovation for a significant cost reduction (see chapter 6.2).

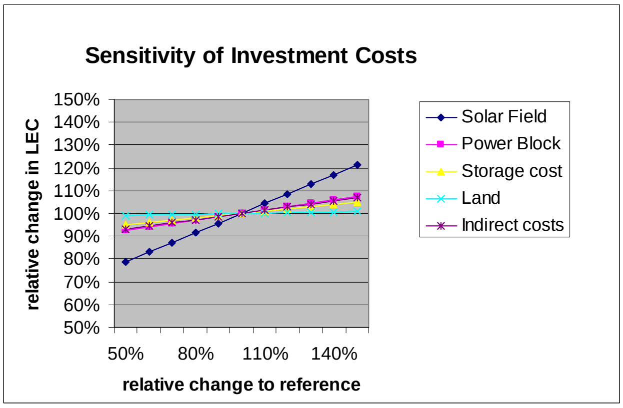


Figure 4-8: Sensitivity the investment cost of solar field, power block, storage costs, land cost and contingencies on the LEC (Trough/Oil).

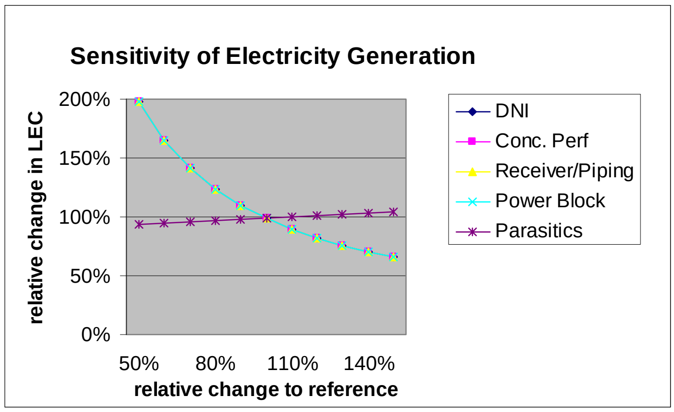


Figure 4-9: Sensitivity of DNI, the performance of concentrator, receiver, power block and parasitics on the LEC. (Trough/Oil).

In Figure 4-9 the sensitivity of the parameters impacting the electricity generation on the solar LEC for a solar-only trough system are shown.
DNI, and the performance of concentrator, receiver and power block are all impacting the LEC in the same strong way. This diagram clearly shows where technical innovation should focus to. The increase of the performance is a significant driver for cost reduction, as long as the investment cost are not increased in a similar way (compare to Figure 4-8).

In Figure 4-10 the sensitivity of the parameters impacting the O&M costs are presented. O&M cost depend significantly on the plant size. The man power costs also have a significant impact. This may offer a cost reduction potential when the technology is deployed in less-development countries with a lower salary level. Also equipment and service costs are not negligible.

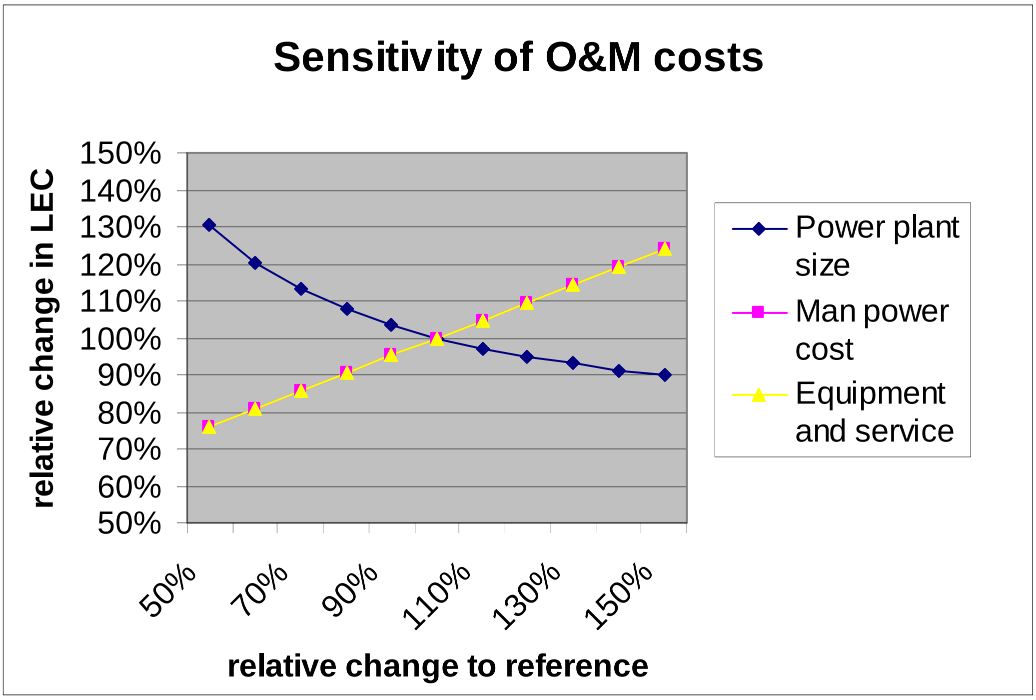


Figure 4-10: Sensitivity of the power plant size, man power costs and equipment and service costs on the LEC

A third level sensitivity analysis going more deeply into the impact of different components can not be performed in a similar generic way. In chapter 5 the impact of specifically considered innovations is studied for the six reference systems considered.

5. Reference Systems

5.1. Parabolic trough technology using thermal oil as heat transfer fluid

5.1.1. Status of technology

Parabolic trough power plants consist of large fields of parabolic trough collectors, a heat transfer fluid/steam generation system, a Rankine steam turbine/generator cycle, and optional thermal storage and/or fossil-fired backup systems [2], [4]. The collector field is made up of a large field of single-axis-tracking parabolic trough solar collectors. The solar field is modular in nature and comprises many parallel rows of solar collectors, normally aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the sun's direct beam radiation on a linear receiver located at the focus of the parabola. The collectors track the sun from east to west during the day to ensure that the sun is continuously focused on the linear receiver. A heat transfer fluid (HTF) is heated up as high as 393ºC as it circulates through the receiver and returns to a steam generator of a conventional steam cycle power plant. Given sufficient solar input, the plants can operate at full-rated power using solar energy alone. During summer months, the plants typically operate for 10–12 hours a day on solar energy at full-rated electric output. To enable these plants to achieve rated electric output during overcast or night time periods, the plants have been designed as hybrid solar/fossil plants; that is, a backup fossil-fired capability can be used to supplement the solar output during periods of low solar radiation. In addition, thermal storage can be integrated into the plant design to allow solar energy to be stored and dispatched when power is required.

In 1983, Southern California Edison (SCE) signed an agreement with Luz International Limited to purchase power from the two first commercial solar thermal power plants named Solar Electric Generating System (SEGS I and II). Later, with the advent of the California Standard Offer power purchase contracts for qualifying facilities under the U.S. Federal Public Utility Regulatory Policy Act (PURPA), Luz was able to sign a number of standard offer contracts with SCE that led to the development of the SEGS III through SEGS IX projects (see Figure 5-1). Initially, PURPA limited the plants to 30 MW in size; this limit was later raised to 80 MW. In total, nine plants were built, representing 354 MW of combined capacity. Table 5-1 shows the characteristics of the nine SEGS plants that Luz built.

In 1991, Luz filed for bankruptcy when it was unable to secure construction financing for its tenth plant (SEGS X). Although many factors contributed to the demise of Luz, the basic problem was that the cost of the technology was too high to compete in the power market with declining energy costs and incentives. However, the ownership of the SEGS plants was not affected by the status of Luz, because the plants had been developed as independent power projects, owned by investor groups, and continue to operate today in that form. Since then, no further commercial plants have been erected, although the cost reduction potential is estimated to be high enough to compete with conventional technologies in the medium term [10].

Table 5-1 : Characteristics of SEGS I through IX [2]

SEGS Plant	First Year of Operation	Net Output (MW_{el})	Solar Field Outlet Temperature (ºC)	Solar Field Area (m^2)	Solar/Fossil Turbine Efficiency (%)	Annual Output (MWh)	Dispatchability Provided by
I	1985	13.8	307	82,960	31.5/ NA	30,100	3 hours— thermal storage Gas-fired superheater
II	1986	30	316	190,338	29.4/37.3	80,500	Gas-fired boiler
III/IV	1987	30	349	230,300	30.6/37.4	92,780	Gas-fired boiler
V	1988	30	349	250,500	30.6/37.4	91,820	Gas-fired boiler
VI	1989	30	390	188,000	37.5/39.5	90,850	Gas-fired boiler
VII	1989	30	390	194,280	37.5/39.5	92,646	Gas-fired boiler
VIII	1990	80	390	464,340	37.6/37.6	252,750	Gas-fired HTF heater
IX	1991	80	390	483,960	37.6/37.6	256,125	Gas-fired HTF heater

Figure 5-1: Power block of the SEGS parabolic trough power plant in Kramer Junction, US.

Recently, new opportunities discussed below may restart the commercial success of the technology.

2 parabolic trough power plants are planned to be build on the plateau of Guadix in the province of Granada/Spain. They are supposed to produce 50MW of electricity each and they will use

parabolic trough technology with synthetic oil as heat transfer fluid. The plants will be equipped with thermal energy storage, in order to provide power even in times without sunshine. The storage technology is based on the two-tank molten salt system, which is coupled to the heat transfer fluid via an oil-salt heat exchanger. When the solar field delivers heat in excess to the amount needed by the power block, this heat may be used to charge the storage. The solar field will be oversized with respect to the nominal thermal input of the steam turbine.
The power block consists of a Rankine cycle with a reheat steam turbine. The upper temperature of the heat transfer fluid is limited to approximately 395°C due to the decomposition of the synthetic oil and the stability of the selective coating of absorber tubes.

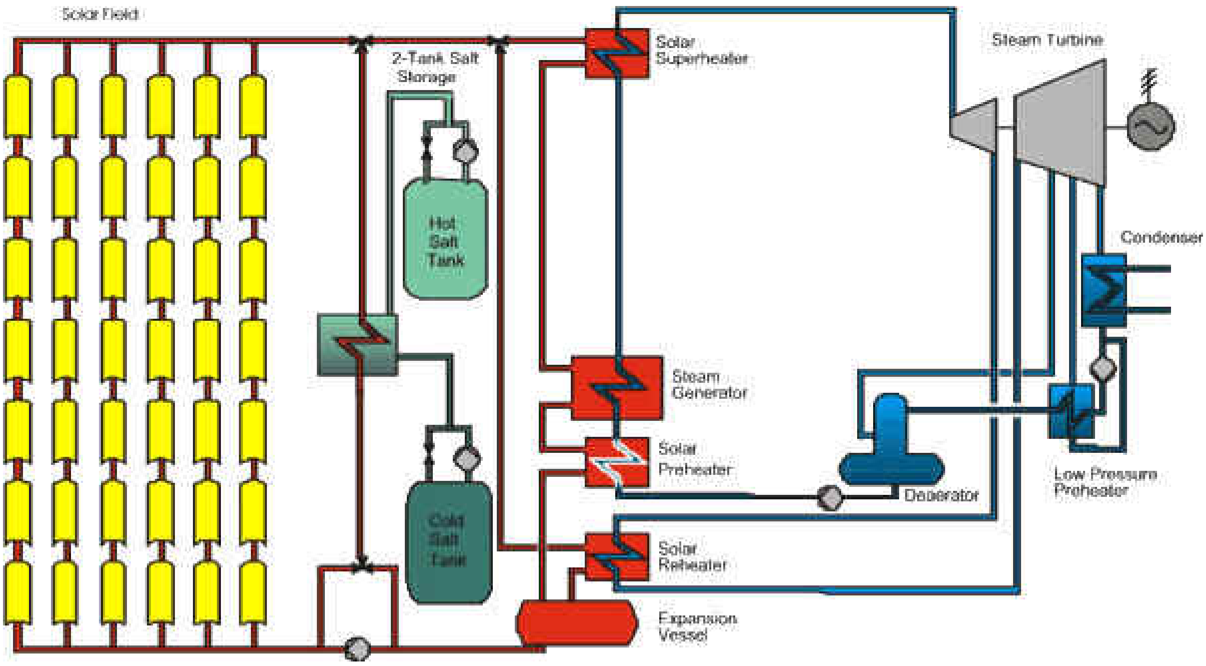


Figure 5-2: Operational scheme of the AndaSol power plants [8]

5.1.2. Cost and performance of reference system

Based on these reference data, we have designed a power plant for the selected site, load curve and other boundary conditions with the lowest solar LEC according to our model. Further optimization in a more detailed model may result in slightly different configuration or cost figures. However, the degree of detail in our model appears sufficient to analyse the overall impact of changes in cost and performance. Design and cost assumptions are summarized in Table 5-2 and Table 5-3.

Table 5-2: Design Data for Parabolic Trough Reference System.

Input data		
site name	Seville	
Longitude	-5.9	°
Latitude	37.2	°
Solar Field		
aperture area of the solar field	442035	m²
total area of the plant	1.72	km²
length of one single collector	150	m
focal length	2.12	m
collector row spacing / aperture width	3	
average reflectivity	0.88	
Optical peak efficiency	0.75	
HTF temperature at field entrance	291	°C
HTF temperature at field exit	391	°C
Factor for Solar field Parasitcs	0.0098	kW/m
design parasitics for pumping and tracking	4332	kW
Factor for power block parasitics	0.03	
operating mode	9:00 a.m. - 11:00 p.m.	
Heat loss factor piping	0.02	W/m²
design net electrical output	50000	kW
design efficiency of the power block	0,375	-
storage capacity	3	h
thermal capacity of the storage	434656	kWh
Storage efficiency	0.95	
HTF temperature in storage discharging	371	°C
Efficiency factor due to lower storage fluid temp.	0.975	

Table 5-3: Cost data used for evaluation of reference concept.

Investment (inc. engineering & construction)		
Specific investment cost for solar field	206	€/m²
Specific investment cost for power block	700	€/kW_{el}
Specific land cost	2	€/m²
Surcharge for construction, engineering & contingencies	20	%
Operation and Maintenance		
Annual O&M costs (43 persons + 1% of investment)	4003490	€/a
Number of persons plant operation	30	
Number of persons for field maintenance	13	
Financial parameters		
Annual insurance cost	1	%/a
Life time	30	Years
Dept interest rate	8.0	%

The plant was designed with a 1.4 times larger solar field than needed to provide the design power (solar multiple = 1.4) and a three hour storage. This LEC optimum was found to be rather flat under the boundary conditions. A larger storage was not economical due to the load curve constraints. The calculation results for solar-only operation as shown in yield to total investments of 176 Mio.€ and LEC of 17.2 cents€/kWh; 3.2 cents€/kWh of this amount is attributed to O&M costs. The plant would achieve a net capacity factor of 28.5%.

Table 5-4: Economical results for the Parabolic Trough reference system[10]

Economical Results		
fixed charge rate	0.0988	
investment solar field	91 059 210	€
investment power block, BOP	39 082 710	€
investment storage	13 474 322	€
investment land	3 447 873	€
contingencies	29 412 823	€
sum total equipment costs	147 064 115	€
total investment including indirect costs	176 476 938	€
specific investment	3 530	€/kW_{el}
annual O&M costs	4 003 490	€
annual financing & insurance costs	17 440 763	€
levelised electricity costs (solar-only)	0.172	€/kWh_{el}
O&M cost / kWh	0.032	€/kWh

The annual performance of the plant is characterized in Figure 5-3. The overall solar-to-net electric efficiency is calculated as 14.0%. This number is higher than the plants performance of the existing SEGS plants in California (10.6%) due to an improved collector design (Eurotrough and new absorber tubes) which are commercially available today. This figure is in accordance

[10] Note that absolute cost data for each of the reference systems are on a different level of maturity, so that no direct comparison between costs of different reference systems appears feasible. The numbers may also deviate significantly from project costs of the first commercial plant currently erected in Spain. However the relative distribution of the different cost items and their relative cost reduction potential is considered to be well estimated by this approach.

to other recent studies (100 MW: 14.0% (net)) [1] on the performance of the next commercial parabolic trough plant.

The relative investment cost distribution is shown in Figure 5-4. Investment costs include engineering and construction of the components. Solar field costs represent the largest share. Storage costs are 8%, which gives an indication that cost reduction by the use of thermal energy storage is very limited under the current equipment cost. The specific cost of the installation is 3530 € /kW_{el}. This appears to be very high compared to conventional power systems, but one must kept in mind, that this number includes "virtually" the lifetime fuel costs of the system. Therefore, this number depends strongly on the capacity factor of the plant. Designing the plant with a lower capacity factor (smaller field, smaller storage system) would reduce this figure, but LEC would increase. For this reason this number is not considered to be useful for comparisons.

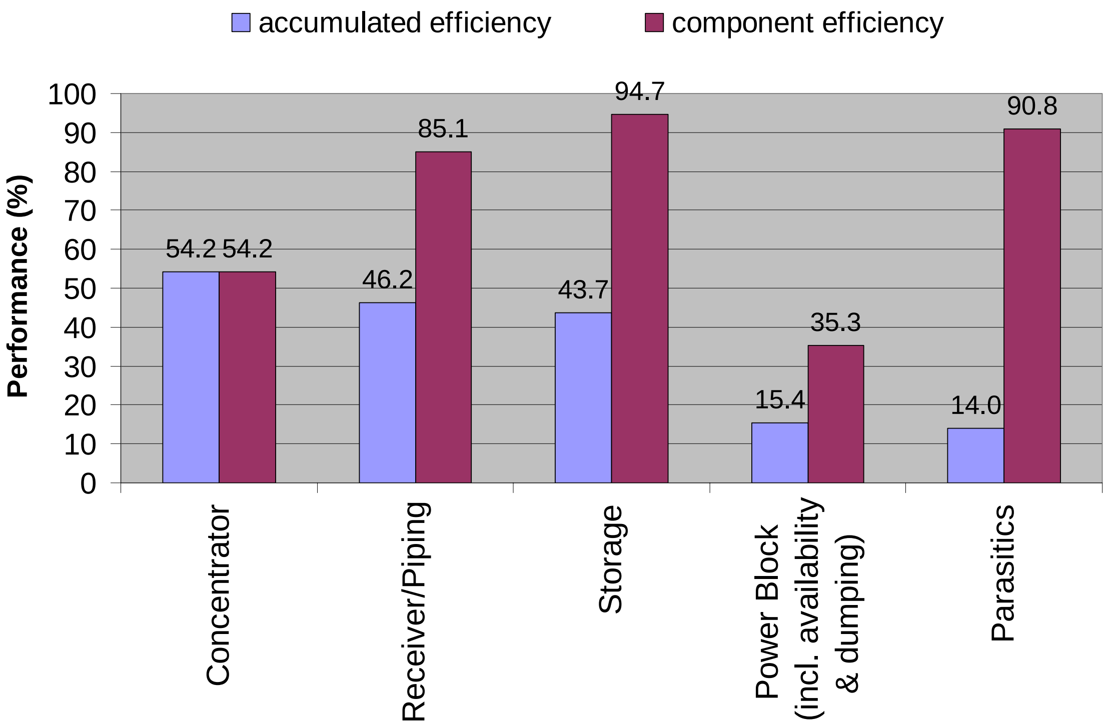


Figure 5-3: Results of annual performance calculation for solar-only operation.

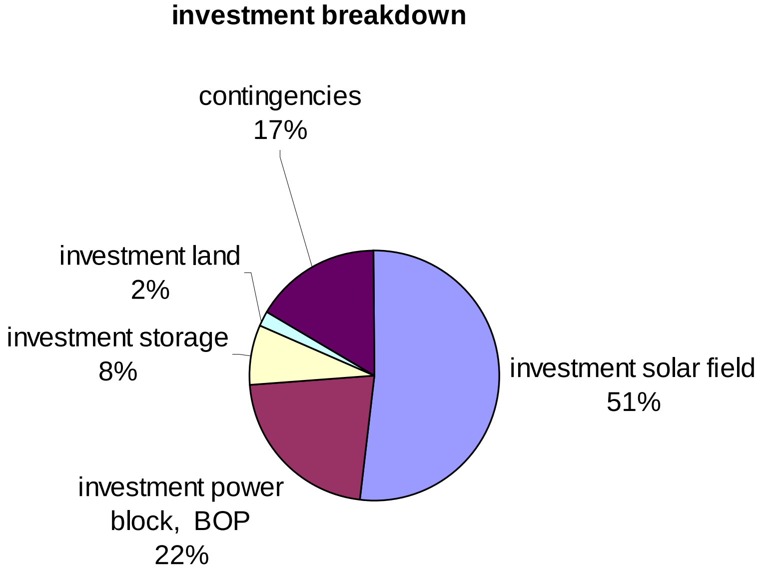


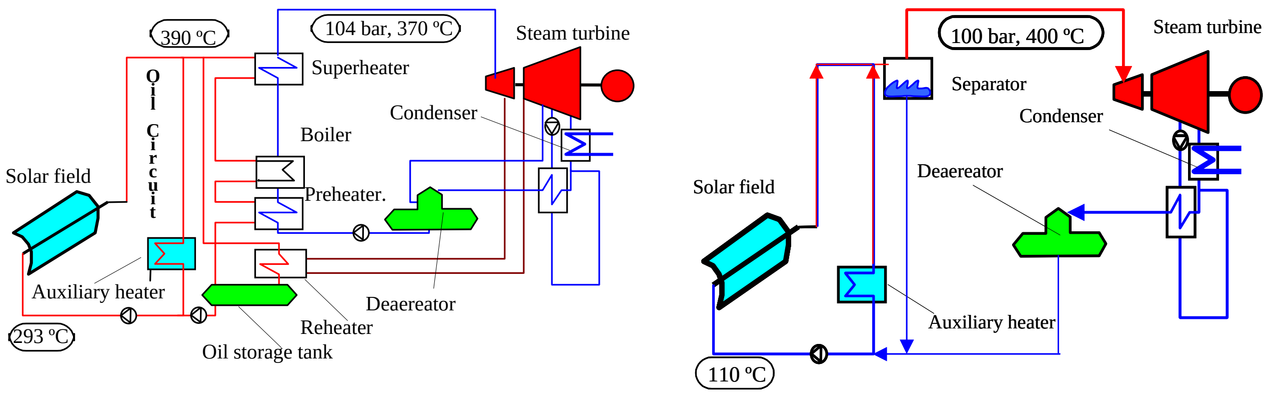
Figure 5-4: Investment breakdown of reference parabolic trough power plant.

Hybrid operation with a large fossil share was not considered beneficial for this kind of CSP plant, since due to the low cycle efficiency (37.5%). Assuming a boiler efficiency of about 95% and a gas price of 15 €/MWh (based on LHV) solely the fuel costs for the fossil electricity generation would be higher than 40 €/MWh, so that electricity from a fossil "shadow power plant" may be the cheaper approach. On an annual basis, for the 9 to 11 full load scheme (capacity factor: 57.1%), the parabolic trough plant with HTF and a 3h thermal storage is able to deliver about 50% of the demanded electricity from solar heat.

5.2. Parabolic trough technology using water/steam as heat transfer fluid

5.2.1. Status of technology

The need of high operating temperatures forced the developer of the existing SEGS plants, the company LUZ, to work in the solar field with thermal fluids (synthetic oils) able to withstand 400ºC. One of the most important objectives of LUZ was the replacement of this expensive heat carrier by water which is directly heated up and converted into superheated steam in the absorber pipes of parabolic trough collectors, thus achieving the steam conditions required to be directly expanded in the turbine connected to an electricity generator (temperatures in the range of 400ºC and pressures around 100bars). This is the so-called Direct Steam Generation (DSG) Process. Replacement of the oil by the DSG process will result in lower investment and operating costs, higher efficiency and reduced environmental risk and fire hazards. Figure 5-5 shows the schematic diagram of a SEGS-like power plant and a solar power plant with DSG. The simplicity and the less complexity of the DSG plant are evident. The challenge of this concept is that a stratified flow in the horizontal tubes may lead to an inhomogeneous absorber temperature on the circumference of the absorber tube, resulting in unacceptable material stress. Fundamental investigation of flow pattern and heat transfer in horizontal tubes in the early nineties, showed, that provided a minimum mass flow is kept in the tubes, acceptable flow conditions can be achieved.



SEGS- like solar power plant DSG solar power plant

Figure 5-5: Simplified scheme of a SEGS plant and a DSG-based plant.

During the first phase of the EU co-funded DISS project (1996-1998) a life-size solar test facility was designed and implemented at the Plataforma Solar de Almería (PSA) to investigate under real solar conditions the DSG process and evaluate the open technical questions concerning this new technology. The cost analysis performed in 1998 showed that, in combination with further improvements of the collector field and overall system integration, a 26% reduction in the electricity cost seems to be achievable with the DSG process. In the second phase of the DISS project (1999-2001), the PSA DISS test facility was used to investigate the three basic DSG processes (i.e., Once-through, Recirculation and Injection) under real solar conditions to find out the best option for a commercial plant.
The PSA DISS facility has already been operated for more than 5500 hours producing superheated steam at 30bar, 60bar and 100bar, and the most important conclusion achieved is the certainty that direct solar steam generation is possible in parabolic trough collectors with horizontal absorber tubes. Other outstanding achievements in DISS were the good performance of the high pressure/temperature ball-joints installed at the DISS facility and the low pressure drop measured at the DSG solar absorbers. At the same time, the temperature gradients

measured at horizontal absorber pipes were within a safety range for operation, even at 40% of nominal flow. Control schemes for Recirculation demise of LUZ, a number of projects were conducted afterwards to investigate the two-phase flow (i.e., liquid water and steam) in horizontal or slightly inclined tubes [9]. Experiments were performed with electrically-heated simulated solar absorber sections, over a wide range of design and operating parameters. Experimental results significantly improved the knowledge of the DSG process at lab scale and numerical models were developed to predict temperature gradients and pressure and Once-through operation modes have been successfully developed and tested also.

Once the feasibility of the DSG process was proven in the project DISS 10, and design/simulation tools had been developed, the EU co-funded project INDITEP (2002-2005) undertook the detail design of a first pre-commercial DSG power plant of 5 MW_{el}. Optimization of some key components for DSG plants (e.g., water/steam separators, selective coatings, etc.) was also included in the work program of INDITEP.

Three basic requirements were defined for the design of this first pre-commercial DSG solar power plant:

a) since there is no previous experience on the operation of a commercial DSG power plant under real solar conditions, the power block selected must be robust and flexible concerning operation conditions to assure a good durability and reliability. Higher priority has therefore been given to power block robustness and flexibility, while efficiency has been considered less critical for this first DSG plant. A superheated steam turbine was chosen in order to fulfil this requirement,
b) the size must be small in order to limit the financial risk for investors. A net nominal power of about 5 MW_{el} was defined for the power block of this first DSG plant in order to achieve a good compromise between a bigger size that would make the plant more profitable and the small size required to limit the financial risk for investors,
c) the solar field must be designed to be operated in recirculation mode because the analysis of the three basic DSG operation modes (i.e., injection, once-through and recirculation) performed within the project DISS showed that recirculation mode is the best option for commercial DSG solar fields.
d)

Figure 5-6 shows a simplified scheme of the power block selected for the plant, with the main technical parameters concerning flow rates, pressures and temperatures. Those technical parameters not displayed in Figure 5-6 are listed in Table 5-5.

Table 5-5: Power block parameters.

Manufacturer	KKK
Gross Power (kW_{el})	5472
Net Power (kW_{el})	5175
Net heat rate (kJ/kWh)	14460
Gross / Net efficiencies (%)	26.34 / 24.9

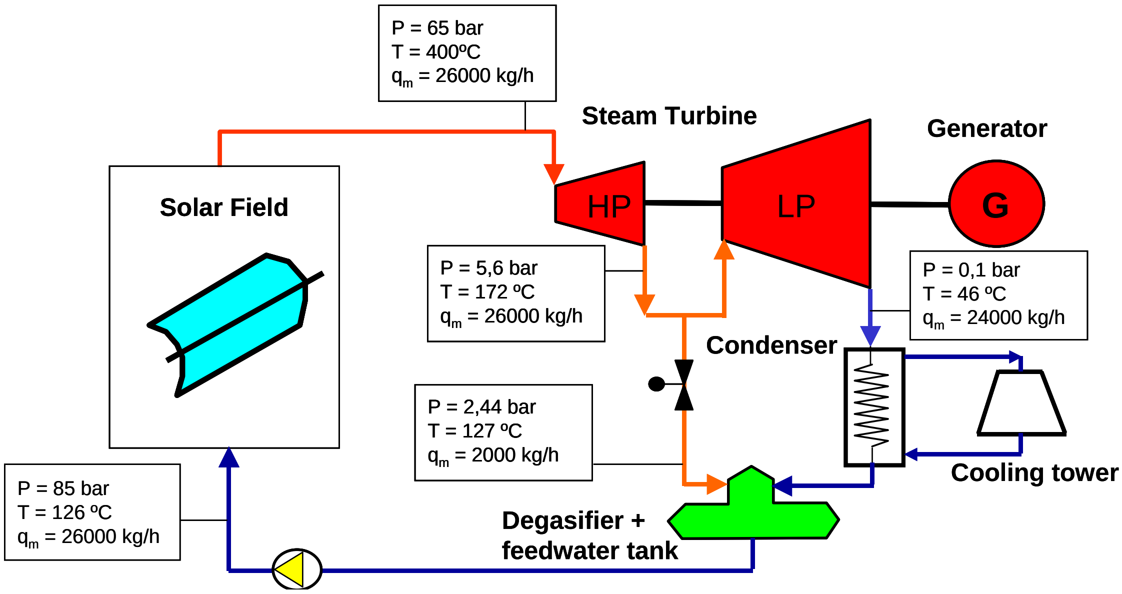


Figure 5-6: Simplified scheme of the power block.

Though the small size of the selected power block could be in principle a handicap for its commercial profitability, this problem can be overcome if external financial incentives that are usually given to demonstration plants are obtained, thus making the implementation and exploitation of this plant financially feasible.

5.2.2. Cost and performance of reference system

Due to the small size of the plant INDITEP, the specific annual cost for O&M is very high because a much larger DSG power plant could be operated with the same staff. At the same time, the low efficiency of its power block (0.26) is caused by its small size. These are the reasons why the levelized electricity cost of such a plant is very high (>0.20 €/kWh). The reasons why a small size was selected for INDITEP have been explained in Section 5.2.1. Since there is no technical barrier at present to design a bigger DSG plant, a DSG reference plant with a net nominal power of 50 MW_{el} could be designed. However, such a design would not represent the state-of-the-art of the DSG technology and therefore is treated as innovation in chapter 7.2. The net electrical power of the DSG reference plant is 47 MW_{el} and it is composed by ten INDITEP plants working in parallel. No storage system is foreseen, because today there are no technical options available. The site and other parameters defined for all the reference systems considered in this road mapping study have been considered in this system also. Table 5-5 and Table 5-6 summarize the system data.

Table 5-6: Design Data for DSG Parabolic Trough Reference System.

Location		
Site name	Seville	(Spain)
Longitude	-5.9	º
Latitude	37.2	º
Annual Solar Direct Insolation	2014	kWh/m²a
Load curve	Solar Only 9:00 a.m. – 11:00 p.m.	
Solar Field Design		
Aperture area of the solar field	448 191	m²
Total area of the plant	1.6	km²
Length of one single collector	150	m
Focal length (average)	2.12	m
Collector row spacing / aperture width	3	
Average reflectivity	0.88	
Optical peak efficincy	0.75	
Water temperature at field entrance	126	ºC
Steam temperature at field exit	411	ºC
Design parasitics for pumping and tracking	4034	kW
Heat loss factor piping	0.02	kW/m²
Power Block Design (10 equal power block units)		
Design net electrical output	47 000	kW
Design efficiency of the power block	26	%
Overall plant availability	0.96	

Table 5-7: Cost data used for evaluation of reference DSG parabolic trough concept.

Investment (inc. engineering & construction)		
Specific investment cost for solar field	190	€/m²
Specific investment cost for power block	435	€/kW$_{el}$
Specific land cost	2	€/m²
Surcharge for construction, engineering & contingencies	20	%
Operation and Maintenance		
Annual O&M costs (43 persons + 1% of investment)	3 515 128	€/a
Number of persons plant operation	30	
Number of persons for field maintenance	13	
Financial parameters		
Annual insurance cost	1	%/a
Life time	30	Years
Dept interest rate	8.0	%

The calculation results for solar-only operation presented in Table 5-8 yield to total investments (including engineering and construction) of 133 Mio.€ and 18.7 cents€/kWh; 3.9 cents€/kWh of this amount is attributed to O&M costs. The plant would achieve a solar net capacity factor of 21.7%.

Table 5-8: Economical results of the INDITEP Reference system[11].

Economical Results		
fixed charge rate	0.0988	
investment solar field	85 156 338	€
investment power block, BOP	22 813 019	€
investment land	3 271 796	€
contingencies	22 248 242	€
sum total equipment costs	111 241 211	€
total investment including indirect costs	133 489 454	€
specific investment	2.840	€/kW$_{el}$
annual O&M costs	3 515 128	€
annual financing & insurance costs	13 192 420	€
levelized electricity costs (solar-only)	0.187	€/kWh$_{el}$
O&M cost / kWh	0.039	€/kWh

The annual performance of the plant is characterized in Figure 5-7. The overall solar-to-net electric efficiency is calculated as 9.9%. This number is low because of the low efficiency of the small reference power block.
The relative investment cost distribution is shown in Figure 5-8. Engineering and construction and contingencies are included in the indirect cost figure. Solar field costs represent the largest share (64%). Total investment cost of the power block is 22.8 Mio €, with a specific cost of

[11] Note, that absolute cost data for each of the reference systems are on a different level of maturity, so that no direct comparison between costs of different reference systems appears feasible. The numbers may also deviate significantly from project cost of the first commercial plant currently erected in Spain. However the relative distribution of the different cost items and their relative cost reduction potential is considered to be well estimated by this approach.

435 €/kW$_{el}$ (38% lower than for the HTF reference plant due to the simplicity of the INDITEP power block).

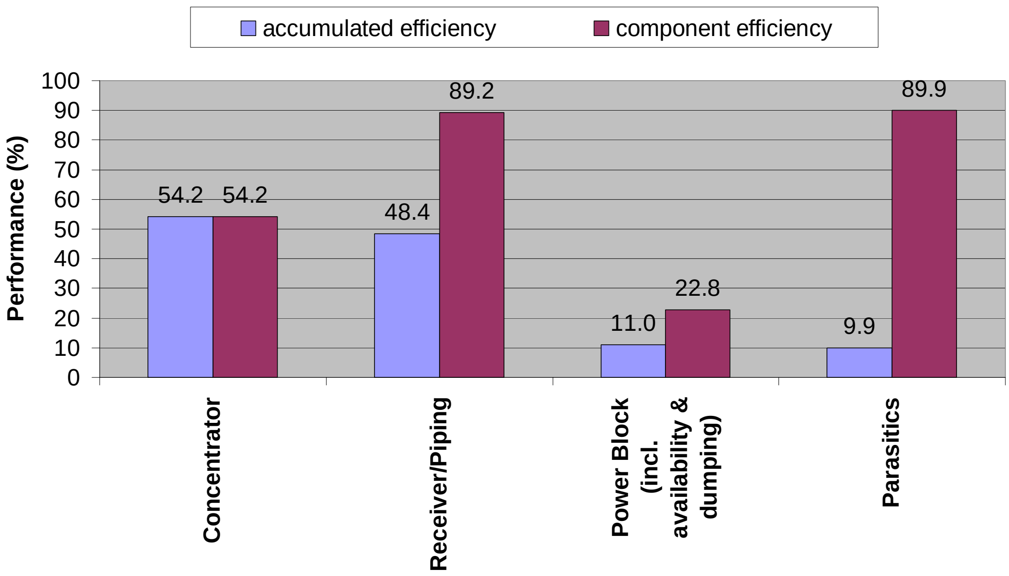


Figure 5-7: Results of annual performance calculation for solar-only operation of the DSG parabolic trough plant made of 10 single units of 4.7MW each.

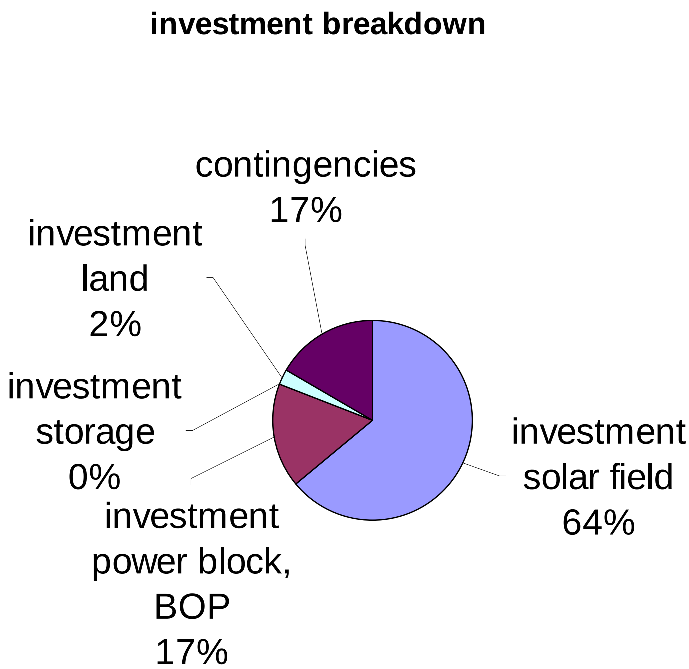


Figure 5-8: Investment breakdown of reference DSG parabolic trough power plant.

The linear Fresnel system may be considered as innovation for the direct steam generating (DSG) parabolic trough system, since it is also designed for DSG rather than for the utilization of a heat transfer fluid. Since the plant design and characteristics are differ significantly from a parabolic trough plant, Linear Fresnel systems have been treated by a separate model and the results are shown in a special manner compared to the other innovations. Linear Fresnel systems suffer from performance drawbacks due to higher intrinsic optical losses compared to parabolic trough systems. The performance cascade for a 50 MW plant in Seville without storage based on performance figures evaluated by Fraunhofer ISE [11] are shown in Figure 5-9 and yield an annual net efficiency of 10.6% compared to 14.1% for a parabolic trough DSG plant of the same block size and operated under in the same temperature range. The inputs for the calculations are summarized in Table 5-9.

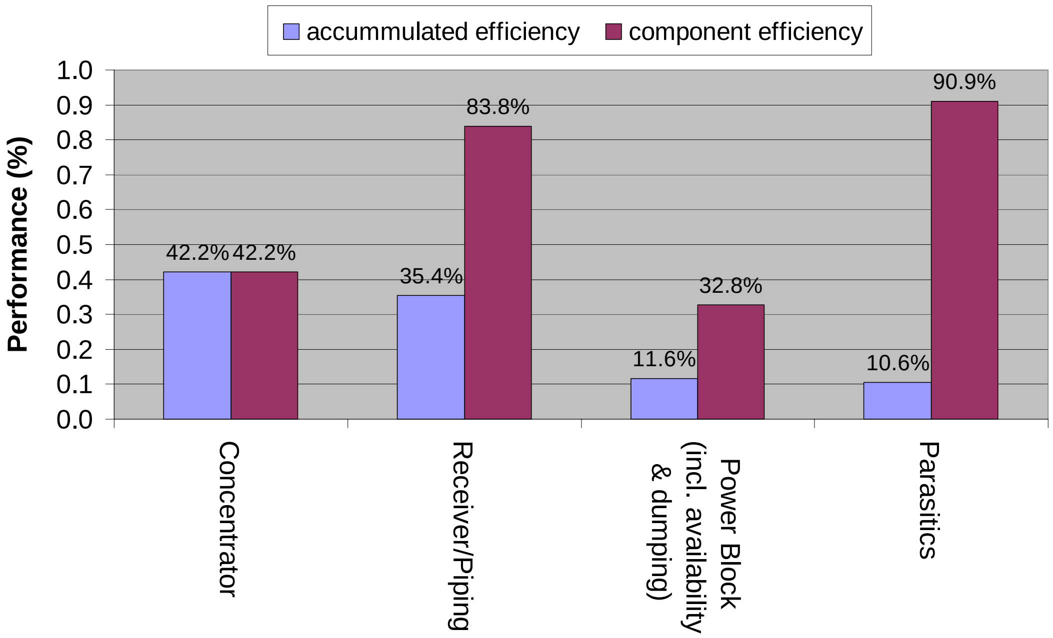


Figure 5-9: Results of annual performance calculation for a Linear Fresnel DSG plant of 50 MW.

Table 5-9: Input Data for DSG System with Linear Fresnel concentrator:

Input data		
site name	Seville	
Longitude	-5.9	
Latitude	37.2	°
Solar Field		
aperture area of the solar field	376200	m^2
total area of the plant	0.5643	km^2
length of one single collector	1000	M
average reflectivity	0.88	
Optical peak efficiency	0.64	
HTF temperature at field entrance	126	°C
HTF temperature at field exit	411	°C
Factor for solar field parasitics	0.009	
Heat loss factor piping	0.02	W/m^2
design parasitics for pumping and tracking	3386	kW
Power Bock		
Factor for power block parasitics	0.03	
design net electrical output	50000	kW
design efficiency of the power block	0.385	
O&M Input		
Labor costs per employee	48000	€/a
number of persons (without field maintenance)	30	
number of persons for field maintenance	7.5	
O&M Equipment costs percentage of investment	1%	per a
Cost input		
specific investment cost for solar field	120	€/m^2
spec. investment cost for power block	700	€/kW_{el}
specific land cost	2	€/m^2
annual insurance cost	0.01	
Life time	30	years
dept interest rate	8	%
surcharge for construction, engineering & contingencies	20	%
Overall plant availability	96	%

Table 5-10: Economical results of the Fresnel system[12].

Economical Results		
fixed charge rate	0.0988	
investment solar field	45 144 000	€
investment power block, BOP	38 420 410	€
investment land	1 128 600	€
contingencies	16 938 688	€
sum total equipment costs	84 693 440	€
total investment including indirect costs	101 632 128	€
specific investment	2033	€/kW_{el}
annual O&M costs	2 921 659	€
annual financing & insurance costs	10 044 042	€
levelized electricity costs (solar-only)	0.162	€/kWh_{el}
O&M cost / kWh	0.036	€/kWh

[12] Note, that absolute cost data for each of the reference systems are on a different level of maturity, so that no direct comparison between costs of different reference systems appears feasible. The numbers may also deviate significantly from project cost of the first commercial plant currently erected in Spain. However the relative distribution of the different cost items and their relative cost reduction potential is considered to be well estimated by this approach.

5.3. CRS using molten salt as heat transfer fluid

5.3.1. Status of technology

To provide high annual capacity factors with solar-only power plants, a cost-effective thermal storage system must be integrated. One such thermal storage system employs molten nitrate salt as the receiver heat transfer fluid and thermal storage media. The usable operating range of molten nitrate salt, a mixture of 60% sodium nitrate and 40% potassium nitrate, matches the operating temperatures of modern Rankine cycle turbines. In a molten-salt power tower plant, cold salt at 290 °C is pumped from a tank at ground level to the receiver mounted atop a tower where it is heated by concentrated sunlight to 565°C. The salt flows back to ground level into another tank. To make electricity, hot salt is pumped from the hot tank through a steam generator to make superheated steam. The superheated steam powers a Rankine-cycle turbine. A schematic of a molten-salt power tower is shown in Figure 5-10. The collector field can be sized to collect more power than demanded by the steam generator system and the excess salt is accumulated in the hot storage tank. With this type of storage system, solar power tower plants can be built with annual capacity factors up to 70% [**Fehler! Textmarke nicht definiert.**].

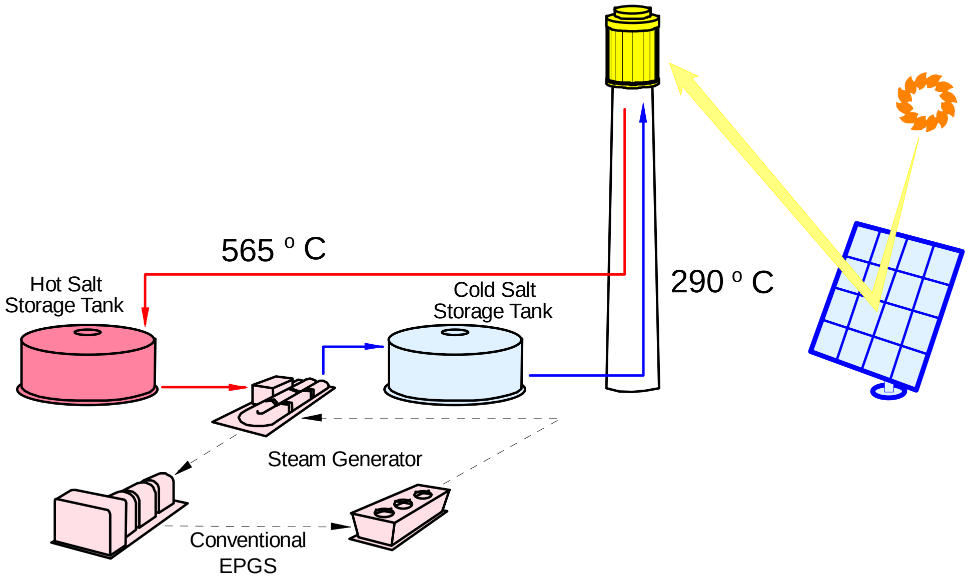


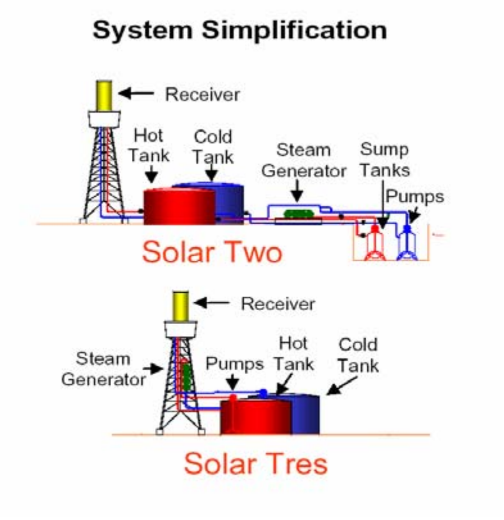
Figure 5-10: Process flow diagram of molten salt SCR plant [12].

Several molten salt development and demonstration experiments have been conducted over the past two and half decades in the USA and Europe to test entire systems and develop components. The largest demonstration of a molten salt power tower was the Solar Two project - a 10 MW power tower located near Barstow, CA.
The purpose of the Solar Two project was to validate the technical characteristics of the molten salt receiver, thermal storage, and steam generator technologies, improve the accuracy of economic projections for commercial projects by increasing the database of capital, operating, and maintenance costs, and to distribute information to utilities and the solar industry to foster wider interest in the first commercial plants. The Solar Two plant was built at the same site as the Solar One pilot plant and reused much of the hardware including the heliostat collector field,

tower structure, 10 MW turbine and balance of plant. A new, 110 MWh_{th} two-tank molten-salt thermal storage system was installed as well as a new 42 MW_{th} receiver, a 35 MW_{th} steam generator system (535°C, 100 bar), and master control system. Additional 108 heliostats each 95 m^2 were refurbished from a defunct photovoltaic facility to supplement the original 1818 heliostats (each 39 m^2) [13].
The plant began operating in June 1996. The project successfully demonstrated the potential of nitrate salt technology. Some of the key results were: the receiver efficiency was measured to be 88%, the thermal storage system had a measured round-trip efficiency of greater than 97%, the gross Rankine-turbine cycle efficiency was 34%, all of which matched performance projections. The collector field under-performed relative to predicted values primarily due to the low availability of heliostats (85 to 95% versus 98% expected), the degradation of the mirrored surfaces, and poor canting of the heliostats. Most of the heliostat problems were attributed to the fact that the heliostat field sat idle and un-maintained for six years between Solar One shut down and Solar Two start-up. The overall peak-conversion efficiency of the plant was measured to 13.5%. The plant successfully demonstrated its ability to dispatch electricity independent of collection. On one occasion, the plant operated around-the-clock for 154 hours straight [14]. The plant met daily performance projections when the actual heliostat availability was accounted for. Although the plant had some start up issues and did not run long enough to establish annual performance or refine operating and maintenance procedures, the project identified several areas to simplify the technology and to improve its reliability. On April 8, 1999, this demonstration project completed its test and evaluations and was shut down.
Since Solar Two was a demonstration project and was quite small by conventional power plants standards, it could not compete economically with fossil fired power plants without special subsidies. Solar-only commercial power tower plants must be larger to take advantage of economy of scales, to have more efficient designs, and to distribute the costs of the maintenance crew over greater energy production [15].
To reduce risks associated with scaling-up hardware, the first commercial molten salt power tower will be approximately three times the size of Solar Two. This project is called Solar Tres and has 17 MW. It is being pursued by the Spanish company Sener, together with Boeing as major supplier of the molten-salt circuit and receiver [16]. Solar Tres will take advantage of several advancements to the molten salt technology since Solar Two was designed and built (Figure 5-11).
These include:

- a larger plant with a heliostat field approximately three times the size of Solar Two (264,825 m^2 of mirrors),
- 2750 large-area glass-metal heliostats each 96 m^2, developed by Sener, which have higher-reflectivity glass,
- a 120-MW_{th} (8.4x10.5 m) cylindrical receiver system with higher flux capability and thus lower heat losses which also is immune to stress corrosion cracking located on top of a 120-m tower,
- a larger thermal storage system (15 hours, 647 MWh, 6250 t salts),
- advanced pump designs that will pump salt directly from the storage tanks eliminating the need for pump sumps [17],
- a 43 MW steam generator system that will have a forced-recirculation steam drum,
- a more efficient (39.4% at design point and 38% annual average), higher-pressure reheat turbine of 17 MW, and
- a simplified molten-salt flow loop that reduces the number of valves.

With these advancements, the peak and annual conversion efficiency will improve over Solar Two's design. Although the turbine will be only slightly larger than Solar Two's turbine, the larger heliostat field and thermal storage system will enable the plant to operate 24 hours a day during the summer and have an annual solar capacity factor of approximately 64% and up to 71% including 15% production from fossil backup [18].



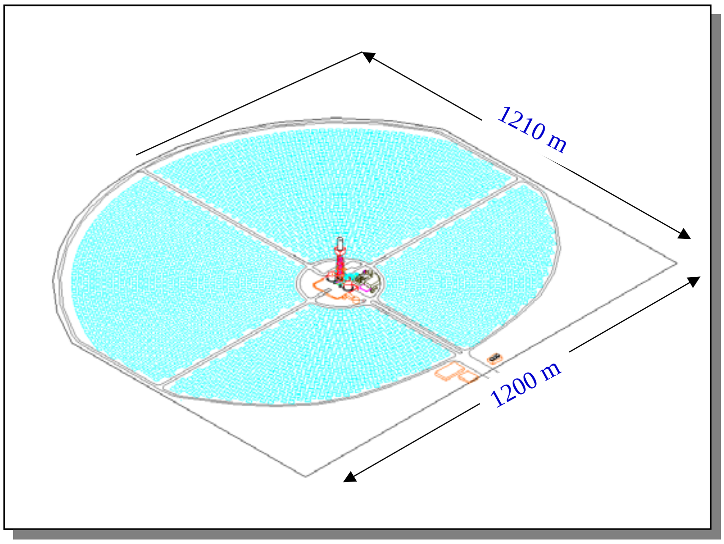


Figure 5-11: System simplification for Solar Tres versus Solar Two and heliostat field layout.

5.3.2. Reference plant definition

- The Solar Tres concept is considered as the current state of the art for molten salt power towers. Thus, a 50 MW reference system is composed of several modules based on 17-MW Solar Tres project with molten salt technology has been sized to accomplish with the common restriction agreed in this project. In this particular case the load curve proposed for the ECOSTAR methodology requires a down-scaling, to meet the design requirements of 14 hours of full load electricity (9 a.m. to 11 p.m.)
- Storage capacity has been fixed to 3 hours, the same value as for the other two CRS technologies using heat storage.
- The solar field has been sized to provide the lowest LEC for the chosen site and load curve (9 a.m. to 11 p.m.).
- Original module technical data have been supplied by the Spanish company SENER. Those aspects not covered by SENER have been obtained from the Second Generation Study [19].
- Receiver efficiency matrix has been introduced using data from Solar Two experience and Second Generation Study [20] [15].
- Characteristics of the solar field (as heliostat size, reflectivity, etc.) are equal to other CRS references.
- The power size of the "module" is, as in the Solar Tres design, 17 MW_{el}. Thus, three modules have been introduced in the "scaling" to approach the common 50 MW_{el} of power for reference comparison with other technologies.

Since there is no technical barrier at present to design a bigger molten salt power plant, a reference plant with a net nominal power of 50 MW_{el} could be designed. However, such a design would not represent the state-of-the-art of the molten salt technology and therefore is treated as innovation in chapter 7.3.

Table 5-11: Technical data for the SCR-molten salt receiver with superheated steam turbine (17-MW original module).

Input data	**17 MW Plant**	**50 MW Plant (3 Modules)**	
site name	Seville	Seville	
Longitude	-5.9	-5.9	°
Latitude	37.2	37.2	°
Heliostat Field			
total reflective area of the solar field	152 720	458 160	m²
total area needed for the power plant	0.611	1.833	km²
area of one heliostat	121.34	121.34	m²
number of heliostats	1259	3776	
mean reflectivity	0.88	0.88	-
Optical peak efficiency	0.75	0.75	-
design parasitics for pumping and tracking	2482	7445	kW
Storage			
storage capacity	3.00	3.00	H
thermal capacity of the storage	153 803	461 409	kWh
storage efficiency	0.95	0.95	-
temperature at storage discharging	560	560	°C
efficiency factor due to lower fluid temperature	0.997	0.997	-
Receiver			
design solar thermal input (to receiver)	73 993	221 979	kW
max. temperature at receiver exit	565	565	°C
Power Cycle			
design net electrical output	17 000	51 000	kW
Design point cycle efficiency	38	38	%

- O&M input parameters are the same than for the SCR air reference. They are shown in next table (Table 5-12).

Table 5-12: O&M input data for molten salt SCR module.

O&M Input	**17 MW Plant**	**50 MW Plant**	
Labor costs per employee	48000	48000	€/a
number of persons (without field maintenance)	30	30	
spec. number of persons for field maintenance	0.030	0.03	1/1000m²
number of persons for field maintenance	4.6	13.7	
Water costs per MWh electricity produced	1.30	1.30	€/MWh
O&M Equipment costs percentage of investment	1%	1%	per a
power block O&M fix	27	27	€/kW
power block O&M variable	2.5	2.5	€/MWh

- Economical information has been estimated by DLR and CIEMAT from SolarPACES data, or extrapolated from PS10 project. Financial scenario, heliostat reflectivity and price, have been adapted according to ECOSTAR general rules (see Table 5-13).

Table 5-13: Economic input data for molten salt SCR module.

Cost input	17 MW Plant	50 MW Plant	
specific investment cost for solar field	150	142	€/m²
spec. investment cost for power block	750	694	€/kW$_{el}$
spec. investment cost for storage	14	13	€/kWh$_{th}$
spec. land costs	2	2	€/m²
total investment cost for tower	2 000 000	5 555 879	€
spec. investment cost for receiver	125	116	€/kW$_{th}$
annual insurance cost	0.01	0.01	
annual O&M costs factor	1.000	1.000	
Life time	30	30	years
dept interest rate	0.08	0.08	
surcharge for construction, engineering & contingencies	0.20	0.20	
Overall plant availability	0.96	0.96	

The performance results, as estimated with the ECOSTAR methodology, are presented in Figure 5-12. The net annual plant performance plant is calculated to be 16%.
The "Economical results" are shown in Table 5-14. LEC for the 50 MW$_{el}$ plant reaches 15.5 cent€/kWh. The O&M contributes to this value with 3.7 cent€. In Figure 5-13, the investment breakdown is shown.
At a first glance the previous figures reveal the strong influence of the cheap "molten salt storage" technology on the whole cost breakdown. For a 50 MW with 3 hours of storage, the percentage of investment produced by the storage system is small (3%).

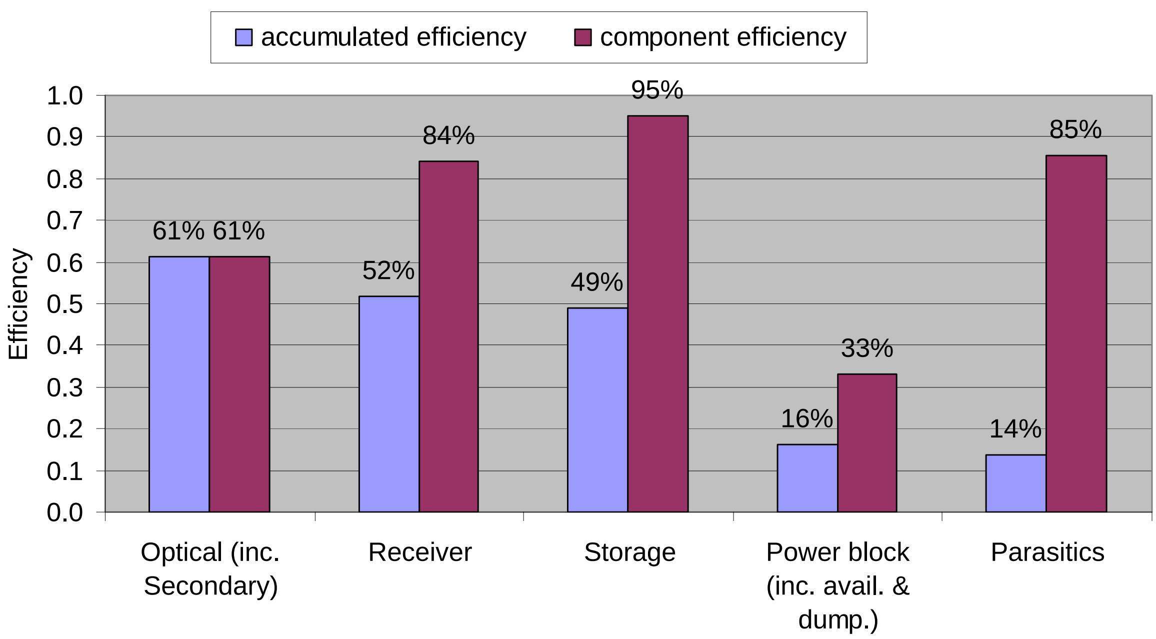


Figure 5-12: Results of annual performance calculation for the molten salt reference plant of 50 MW.

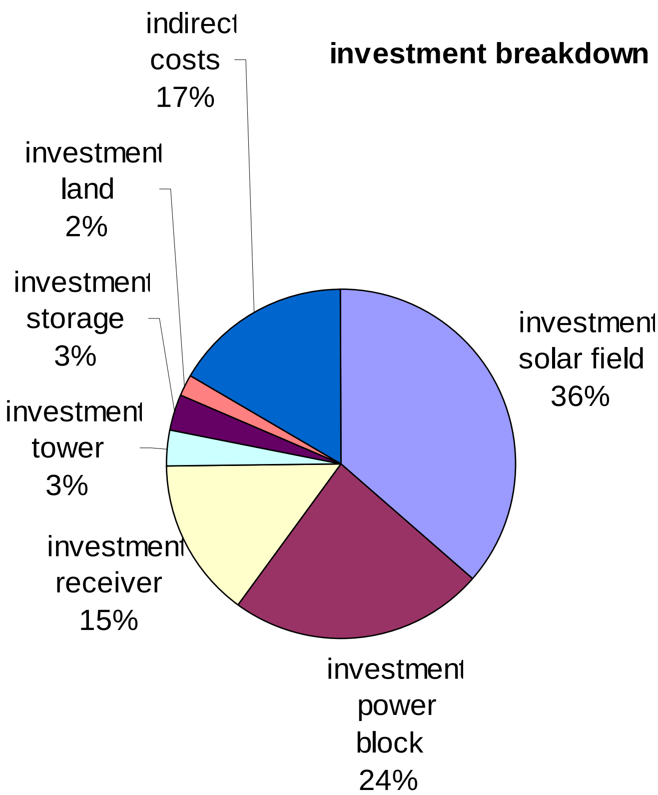


Figure 5-13: Investment breakdown for the molten salt reference plant of 50 MW.

Table 5-14: Economical results obtained for the molten salt SCR plant[13].

Economical Results	17 MW Plant	50 MW Plant	
fixed charge rate	0.0988	0.0988	
Investment solar field	22 908 000	65 050 759	€
Investment power block	14 993 903	41 652 152	€
Investment receiver	9 249 105	25 693 453	€
Investment tower	2 000 000	5 555 879	€
Investment storage	2 153 241	5 981 572	€
Investment land	1 221 760	3 665 280	€
indirect costs	10 505 202	29 519 819	€
sum total equipment costs	52 526 008	147 599 095	€
total investment including indirect costs	63 031 210	177 118 914	€
specific investment	3,708	3,473	€/kW_{el}
annual O&M costs	2 832 888	5 518 874	€
annual financing & insurance costs	6 229 213	17 504 208	€
levelized electricity costs	**0.1825**	**0.1545**	**€/kWh_{el}**

In this sense it can be expected that larger storage capacities would be in principle possible and are meant to improve LEC figures. The circular field used for the Solar Tres design is leading also to small towers that represent only 3% of the investment.
Annual performance by components reveals relatively high efficiencies for all of them (Figure 5-12).
Although showing attractive levelized electricity cost, major uncertainty of the concept is the plant availability. Experiences in the Solar Two demonstration plant revealed a variety of problems caused by the molten salt. Corrosion and problems with the trace heating to prevent the freezing as well delayed start-up yield very low availability figures. The current design has addressed these problems by a variety of design modifications. However, the fact is still perceived as risk and may result in higher costs for the first system due to high risk surcharges.

[13] Please note that absolute cost data for each of the reference systems are on a different level of maturity, so that no direct comparison between costs of different reference systems appears feasible. The numbers may also deviate significantly from project cost of the first commercial plant currently erected in Spain. However the relative distribution of the different cost items and their relative cost reduction potential is considered to be well estimated by this approach.

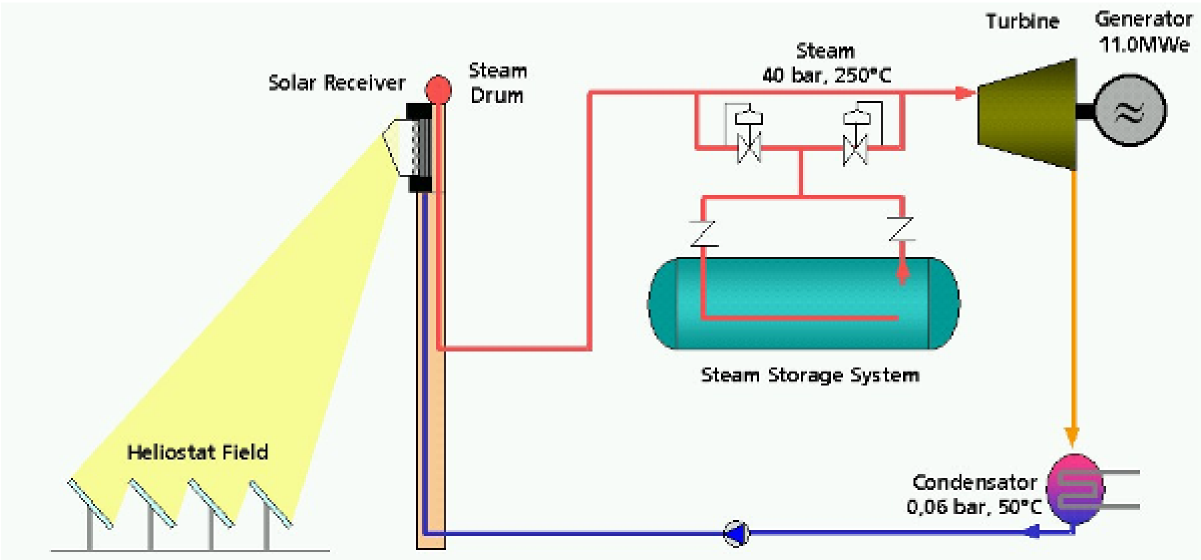
5.4. CRS using saturated steam as heat transfer fluid

5.4.1. Status of technology

Production of superheated steam at the solar receiver has been demonstrated in several plants like Solar One, Eurelios or CESA-1, but the operational experience evidenced critical problems related to the control of zones with dissimilar heat transfer coefficients like evaporators and superheaters [**Fehler! Textmarke nicht definiert.**]. Better results regarding absorber panels' lifetime and controllability have been reported for saturated steam receivers. In particular the STEOR pilot plant (Solar Thermal Enhanced Oil Recovery) for oil extraction using direct injection of steam was successfully operated in Kern County, California, during 345 days in 1983 with a high reliability [**Fehler! Textmarke nicht definiert.**]. The good performance of saturated steam receivers was also qualified at the 2 MW Weizmann receiver tested in 1989 that produced steam at 15 bar for 500 hours [21]. Even though utilizing saturated steam receivers reduces technical risks, the outlet temperatures are significantly lower than those of superheated steam making necessary to limit the size of the heat storage or to search for applications where heat storage is replaced by fossil fuel backup.

Solar-specific electricity costs drop 25% in a hybrid plant relative to a solar-only plant. This is caused by reduced financial risk associated with the solar system and caused by lower costs of solar electricity which leads to lower incremental capital, lower incremental O&M and improved efficiency [22]. Two projects subsidized by the European Commission, the project SOLGAS promoted by SODEAN and the project COLON SOLAR promoted by SEVILLANA [18], have established the strategy of penetration on the basis of the integration of the saturated steam receivers into cogeneration systems and the repowering of combined cycles. The size of the cavity receiver was optimized to supply 21.8 MW_{th} to the fluid at 135 bar and 332.8ºC outlet temperature. The collector subsystem consisted of 489 heliostats (each with a 70 m^2 reflective surface) and a 109-m tower. Integrating power towers into existing combined cycle plants can create issues with respect to heliostat field layout, since the solar field is forced to make use of sites nearby gas pipelines and industrial areas. Land becomes a non-negligible portion of the plant cost and site constraints lead to some particular problems for layout optimization and subsequent optical performance. This was the case for COLON heliostat field and represented a real challenge during the design phase, because of the important restrictions stemming from the available site [23]. The feasibility project of the SOLGAS plant was completed at the beginning of 1996 and had its continuation in the project COLON SOLAR whose detailed design was finalized in April of 1998 [24]. The SOLGAS scheme predicts annual solar shares in the range of 8-15%. With the existing legal framework for solar thermal electricity in Spain this concept is not eligible, forcing developers and promoters to explore stand-alone options with a marginal contribution of fossil backup.

At present the state-of-the-art for the saturated steam technology is represented by the PS10 project. PS10 makes use of the former COLON SOLAR scheme with a cavity receiver including vertical panels producing saturated steam. The systems make use of a glass-metal heliostat field, a saturated steam cavity receiver, a saturated steam storage vessel and a saturated steam turbine (Figure 5-14). Under Spanish electricity regulations, gas may not be used to superheat steam. The 10-MW PS10 plant, promoted by the IPP Sanlúcar Solar through the Solúcar Energía company, will be located on the Casa Quemada estate (37.2º latitude) near the town of Sanlúcar la Mayor, 15 km West of Seville [25].



General Description		
Emplacement	Sanlúcar M. (Sevilla), Lat 37.4º, Lon 6.23º	
Nominal Power	11.02MWe	
Tower Height	90m	
Receiver Technology	Saturated Steam	
Receiver Geometry	Cavity180º, 4 Pannels 5m x 12m	
Heliostats	624 @ 121m2	
Thermal Storage Technology	Water/Steam	
Thermal Storage Capacity	15MWh, 50min @50% Rate	
Steam Cycle	40bar 250ºC, 2 Pressures	
Electric Generation	6.3kV, 50Hz -> 66kV, 50Hz	
Land	60Has	
Annual Electricity Production	24.2GWh	
Nominal Rate Operation		
Optical Efficiency	77.0%	67.5MW -> 51.9MW
Receiver and Heat Handling Efficiency	92.0%	51.9MW -> 47.7MW
Thermal Power to Storage		11.9MW
Thermal Power to Turbine		35.8MW
Thermal Pow. -> Electric Pow. Efficiency	30.7%	35.8MW -> 11.0MW
Total Efficiency at Nominal Rate	21.7%	
Energetical Balance in Annual Basis		
Mean Annual Optical Efficiency	64.0%	148.63GWh(useful) -> 95.12GWh
Mean Annual Receiver&Heat Handling Efficiency	90.2%	95.12GWh -> 85.80GWh
Operational Efficiency (Starts Up/Stops)	92.0%	85.80GWh -> 78.94GWh
Mean Annual Thermal Ener. -> Electric Efficiency	30.6%	78.94GWh -> 24.2GWh
Total Annual Efficiency	16.3%	

Figure 5-14: (Up) Process flow diagram of the PS10 solar tower power plant, based on saturated steam receiver (Nominal gross power is 11 MW). (Down) Technical specifications for PS10 SOLUCAR project [25].

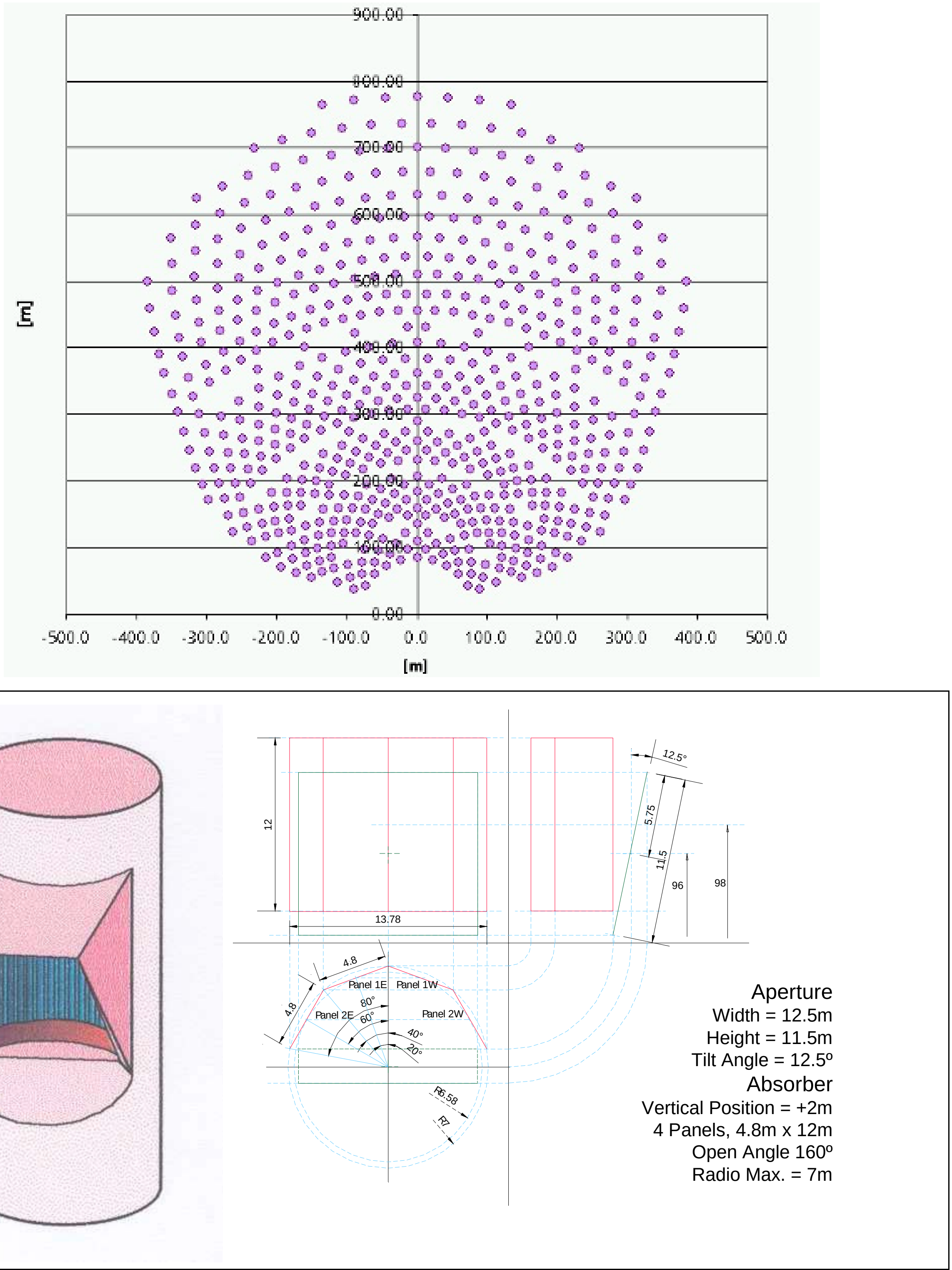


Figure 5-15: (Up) Geometrical arrangement for 624 units in the Heliostat Layout at PS10 Plant. (Down) Geometrical arrangement of cavity receiver [25].

A heliostat field (624 units, 121 m^2 each) concentrates solar radiation onto a receiver placed on the top of a tower (90 m optical height), as depicted in Figure 5-15. The cavity concept receiver was designed to reduce radiation and convective losses as much as possible, providing 90%

thermal efficiency, annual average. The tube panels (4 vertical panels 5x12 m) inside the receiver are independent and spaced to allow thermal expansion and mechanical deformation without causing breaks or leaks. The receiver produces saturated steam at 40 bar/ 250ºC, and feeds it into a drum that increases system thermal inertia. Steam is sent to the turbine where it expands to produce mechanical work and electricity. At the turbogenerator outlet it is sent to a water-cooled condenser at 0.06 bar working pressure. The condenser outlet is preheated with turbine extraction at 0.8 and 16 bar. Output from the first preheater is sent to a deaerator fed with steam from another turbine extraction. A humidity separator will be provided between high and low turbine pressure bodies to increase the steam title in the last stages of expansion. A third and last preheater is fed with steam from the receiver, increasing water temperature to 245ºC. When mixed with returned water from the drum, a 247ºC input water to the receiver is obtained.
For cloud transients, the plant has a saturated steam heat storage system with a 15-MWh thermal capacity (50 minutes at 50% load). During full load operation of the plant, part of the steam produced by the receiver at 250ºC-40 bar is employed to load the thermal storage system. Conversion efficiency of the power block at design point and with 250ºC steam reaches 30.7%. With this value, the system efficiency is 21.7% at design point and 16.3% annual average, with 24 GWh (gross) annual electricity production estimated.

5.4.2. Reference Plant Characteristics

The reference module established for ECOSTAR study has been obviously based on PS10 project information, with some additional inputs from previous references obtained in other recent projects like COLON SOLAR. To implement the methodology agreed for ECOSTAR, one of the main difficulties with saturated steam SCR plants is the pre-fixed load curve. It is at present not technically feasible to propose a typical module working stand-alone from 9 am to 11 pm based on saturated steam storage. The solution decided for PS10 is based on a 15-MWh thermal capacity that has been optimized in terms of operation modes. Operation from the heat storage is done following a part-load strategy with 50% load of turbine, so that the ability to dispatch can be extended to 50 minutes. This means that the state-of-the-art plant for the early plants is using 20-minute nominal storage. Taking into account those restrictions, the following assumptions have been made for the reference case:

- the plant module has a very small storage capacity. Thus it is not able to provide the 14 hours full load operation without hybridization. In the current analysis no hybridization has been considered.
- storage capacity has been fixed to 0.4 hours at full load.
- the solar field has been sized in accordance with the PS-10 project but augmented a little bit to reduce the resultant LEC (a previous parametric analysis was carried out for this purpose). The optimum module was obtained for a solar field of 766 heliostats (of 121 m^2) instead of 624 of the PS-10 project.
- original module technical data have been supplied by the company Solucar and ABENER.
- receiver efficiency matrix has been introduced in a similar way to the SCR Molten Salt case with a slightly higher efficiency. Values of nominal efficiency of 92% are expected because of the low operating temperature (250ºC) and the use of a cavity-type receiver.
- characteristics of the solar field (as heliostat size, reflectivity, etc.) are equal to other CRS references.
- the power size of the "module" is 11 MW_{el}. Thus, five modules have been introduced in the "scaling" to approach the common 50 MW_{el} of power for reference comparison with other technologies. The integration of the concept in one 50 MW power block will be considered as innovation in chapter 1.1.

Table 5-15: Technical input data for the SCR saturated steam plant.

Input data	**11 MW**	**5 x 11 MW Plant**	
site name	Seville	Seville	
Longitude	-5.9	-5.9	°
Latitude	37.2	37.2	°
Heliostat Field			
total reflective area of the solar field	93006	465032	m^2
total area needed for the power plant	0.372	1.86	km^2
area of one heliostat	121.34	121.34	m^2
number of heliostats	766	3832	
mean reflectivity	0.88	0.88	
Optical peak efficiency	0.75	0.75	
Factor for Solar field Parasitcs	0.0016	0.0016	
design parasitics for pumping and tracking	149	744	kW
Receiver			
max. fluid temperature at receiver exit	260	260	°C
design solar thermal input (to receiver)	45062	225308	kW
design net electrical output	11000	55000	kW
Power block			
Factor for power block parasitics	0.03	0.03	
design efficiency of the power block	0.303	0.303	
mean plant availability	0.96	0.96	
Storage			
storage capacity	0.40	0.40	h
thermal capacity of the storage	14718	73590	kWh
storage efficiency	0.95	0.95	
temperature at storage discharging	260	260	°C
Efficiency factor due to lower fluid temperature	0.8	0.8	

For O&M cost the common ECOSTAR assumption are used, specific costs data has been taken from Solucar and Abener (see next tables).

Table 5-16: O&M input for the SCR saturated steam plant.

O&M Input	11 MW	5 x 11 MW Plant	
Labor costs per employee	48000	48000	€/a
number of persons (without field maintenance)	30	30	
spec. number of persons for field maintenance	0.030	0.03	$1/1000m^2$
number of persons for field maintenance	2.8	14.0	
Water costs per MWh electricity produced	1.30	1.30	€/MWh
O&M Equipment costs percentage of investment	1%	1%	per a
power block O&M fix	20	20	€/kW
power block O&M variable	2.6	2.6	€/MWh

Table 5-17: Cost input data for the SCR saturated steam plant.

Cost input	11 MW	5 x 11 MW Plant	
specific investment cost for solar field	150	138	€/m^2
spec. investment cost for power block	636	568	€/kW_e
spec. investment cost for storage	100	89	€/kWh_{th}
spec. Land costs	2	2	€/m^2
total investment cost for tower	2 000 000	8 934 538	€
spec. investment cost for receiver	110	98	€/kWh_{th}
annual insurance cost	0.01	0.01	
annual O&M costs factor	1.000	1.000	
Life time	30	30	Years
dept interest rate	0.08	0.08	
surcharge for construction, engineering & contingencies	0.20	0.20	
Overall plant availability	0.96	0.96	

Regarding performance, it can be observed that due to the small storage size the system is only able to provide a small capacity factor (26.4%). Annual production for the base module is 25.5 GWh. Receiver efficiency offers very high annual values because of the low-temperature and cavity design. As it can be observed in Figure 5-16, this annual value can reach 88% so that very little room exists for improvements in receiver performance. Another key aspect of this design is the relatively low efficiency offered by the saturated steam PB (31% gross). Saturated steam turbine cycles are also penalized by a high O&M of the turbine. Annual efficiency of the whole plant is 13.6%.
Regarding economical figures, it can be observed that in this case the power block is the second largest factor in influence, representing 25% of total. A replicated plant containing 5 modules of 11-MW each would reach a LEC of 16.8 €/MWh.

Table 5-18: Economical results of the SCR saturated steam plant.[14]

Economical Results	11 MW	5 x 11 MW Plant	
fixed charge rate	0.0988	0.0988	
investment solar field	13 950 972	64 361 472	€
investment power block	7 300 593	32 613 714	€
investment receiver	4 956 780	22 143 271	€
investment tower	2 000 000	8 934 538	€
investment storage	1 471 790	6 574 882	€
investment land	744 052	3 720 259	€
indirect costs	6 084 838	27 669 628	€
sum total equipment costs	30 424 188	138 348 138	€
total investment including indirect costs	36 509 025	166 017 765	€
specific investment	3 319	3 019	€/kW_e
annual O&M costs	2 175 105	4 977 789	€
annual financing & insurance costs	3 608 093	16 407 110	€
levelized electricity costs	0.2272	0.1681	€/kWh_e

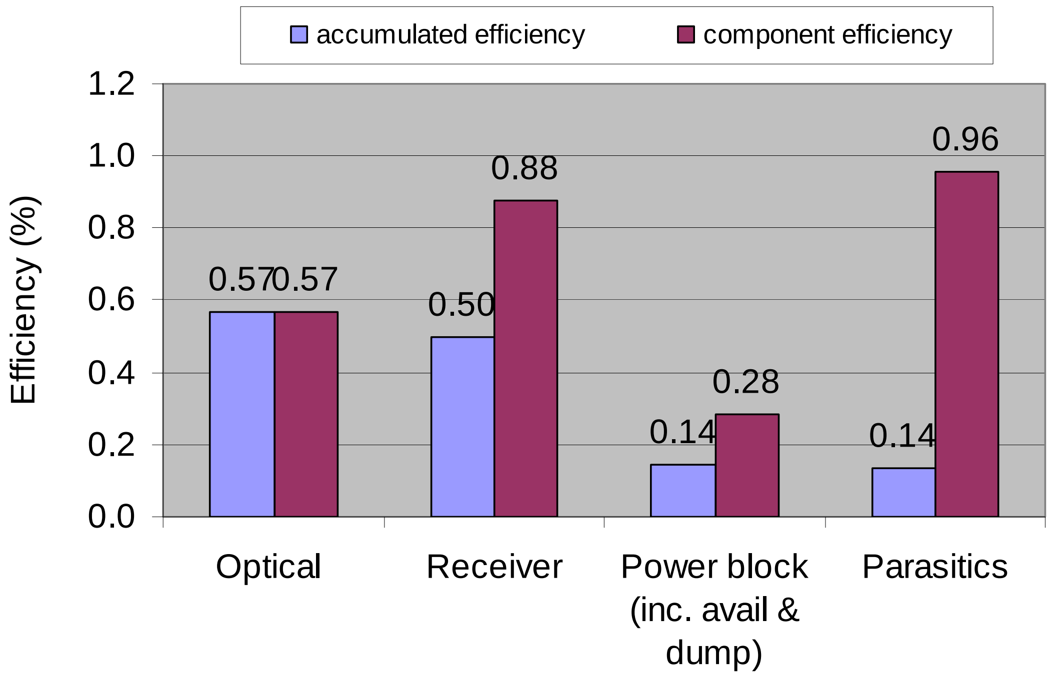


Figure 5-16: Annual performance cascade for the SCR saturated steam plant.

[14] Please note that absolute cost data for each of the reference systems are on a different level of maturity, so that no direct comparison between costs of different reference systems appears feasible. The numbers may also deviate significantly from project costs of the first commercial plant currently erected in Spain. However the relative distribution of the different cost items and their relative cost reduction potential is considered to be well estimated by this approach.

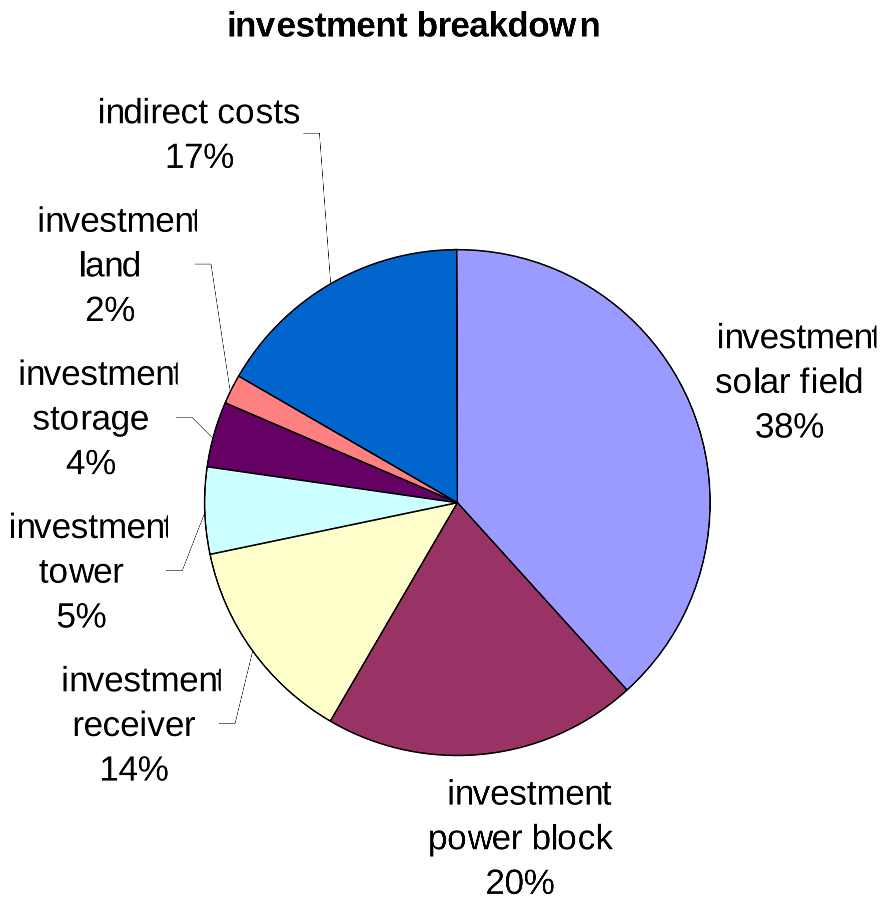


Figure 5-17: Breakdown, in percentage, of investment costs.

5.5. CRS using atmospheric air as heat transfer fluid

5.5.1. Status of technology

The concept presented in this section is a central receiver solar power plant with an atmospheric air heat transfer circuit based on the so-called PHOEBUS scheme (Figure 5-18), where atmospheric air is heated up through a porous absorber receiver to temperatures in the order of 700ºC and used to produce steam at 480-540ºC and 35-140 bar, in a heat recovery steam generator with separate superheater, reheater, evaporator and economizer sections feeding a Rankine turbine-generator system. The PHOEBUS scheme integrates several equivalent hours of ceramic thermocline thermal storage able to work for charging and discharging modes by reversing air flow with two axial blowers [**Fehler! Textmarke nicht definiert.**]. Current heat storage capacity restrictions lead to designs with a limited number of hours (between 3 and 6 hours maximum), therefore for higher annual capacity factors hybrid designs are proposed with the backup from a duct burner located in the downcomer of the receiver.

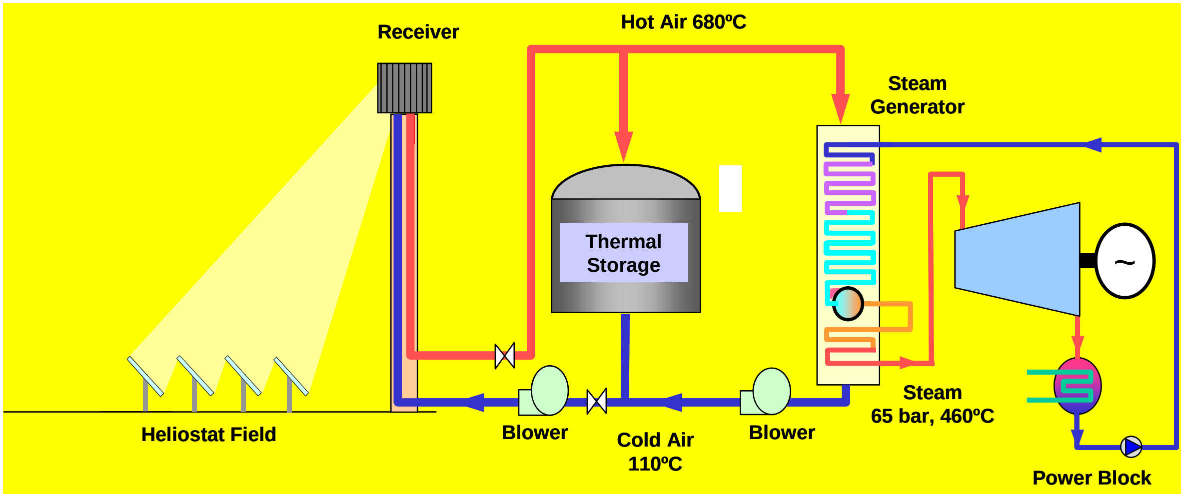


Figure 5-18: Process flow diagram of the PS10 solar tower power plant, based on volumetric air-cooled receiver (Nominal gross power is 11 MW).

In 1986 under the initiative of SOTEL and DLR the study of a 30 MW plant for Jordan was initiated. The international PHOEBUS Consortium was formed by companies from Germany, Switzerland, Spain and the USA and the feasibility study completed in March 1990 [26]. Unfortunately the project could not complete the necessary grants and financial support and did not come to eventual construction. Technology development of key components followed through the German TSA Consortium (Technology Program Solar Air Receiver), with the leadership of the company Steinmüller. A 2.5 MW_{th} air-receiver facility comprising the complete PHOEBUS-power plant cycle that included air-recirculation loop, thermal storage and steam generator was assembled on top of the CESA-1 tower in Spain at the end of 1991. The plant was successfully operated by DLR and CIEMAT for a total of nearly 400 hours between April and December 1993, and for shorter periods in 1994 and 1999, demonstrating that a receiver outlet temperature of 700ºC could easily be achieved within twenty minutes of plant start-up [27]. The benefit of the technology was mainly seen by its simple design concept based on atmospheric air as heat transfer medium compared to synthetic oil or molten salt systems, thus promising high availabilities from the very beginning.

TSA operational results attracted the interest of the Spanish company Abengoa that decided to analyze the Phoebus scheme as one of the options for the design of its first commercial demonstration plant. The project named PS10 started in 1999 and its goal is the construction and connection to the grid of a 10 MW plant to be located in Seville (Spain). Even though PS10 project finally selected water/steam as the option for the plant, the detailed engineering carried out on air/volumetric scheme between 2000 and 2003, remains as the state of the art for SCR with air and Rankine cycle [28].

Some distinctive features of the original PS10-scheme developed by Abengoa are [18]:

- North heliostat field with 781 heliostats (121.34 m^2 each) developed by Solucar. Heliostat has a wide aspect ratio 9575 x 12925 mm and 2.1 mrad beam quality, though with relevant elipticity out of noon time.
- Wire-mesh volumetric receiver making use of the same modular absorber already qualified at the 2.5 MW_{th} TSA receiver but the aperture shape is sectional cylindrical. Air mass flowrate: 65.35 kg/s. Thermal efficiency of receiver at design point: 74.85%
- Absorber material lifetime risks limited by reducing the outlet temperature of the air from 700 ºC to 680ºC.
- Low air-return temperature (110ºC), to minimize losses. Air return ratio: 45%.
- Al_2O_3 ceramic saddles geometry of ¾ inch for the storage core material (390 t). The size of the heat storage (∅ 10 x 8 m) has been reduced to 20 MWh total capacities by running from storage at a reduced air mass flow rate corresponding to approximately 70 % of the nominal value.
- Two pressure steam turbine of 11 MW (gross) and 10 MW (net). Annual efficiency: 30.6%.
- Natural draft two-pressure heat recovery steam generator. Live steam: 80 bar / 515°C (outlet) and 3 bar/150°C (inlet). Hot inlet air: 680°C. Cool outlet air: 100°C

A recent design for Abengoa, conducted by the German company KAM, updates PS10 design including a new receiver with modular structure and ceramic absorber based on technology developed within the European project SOLAIR [29]. The compact design of the tower is depicted in Figure 5-19.

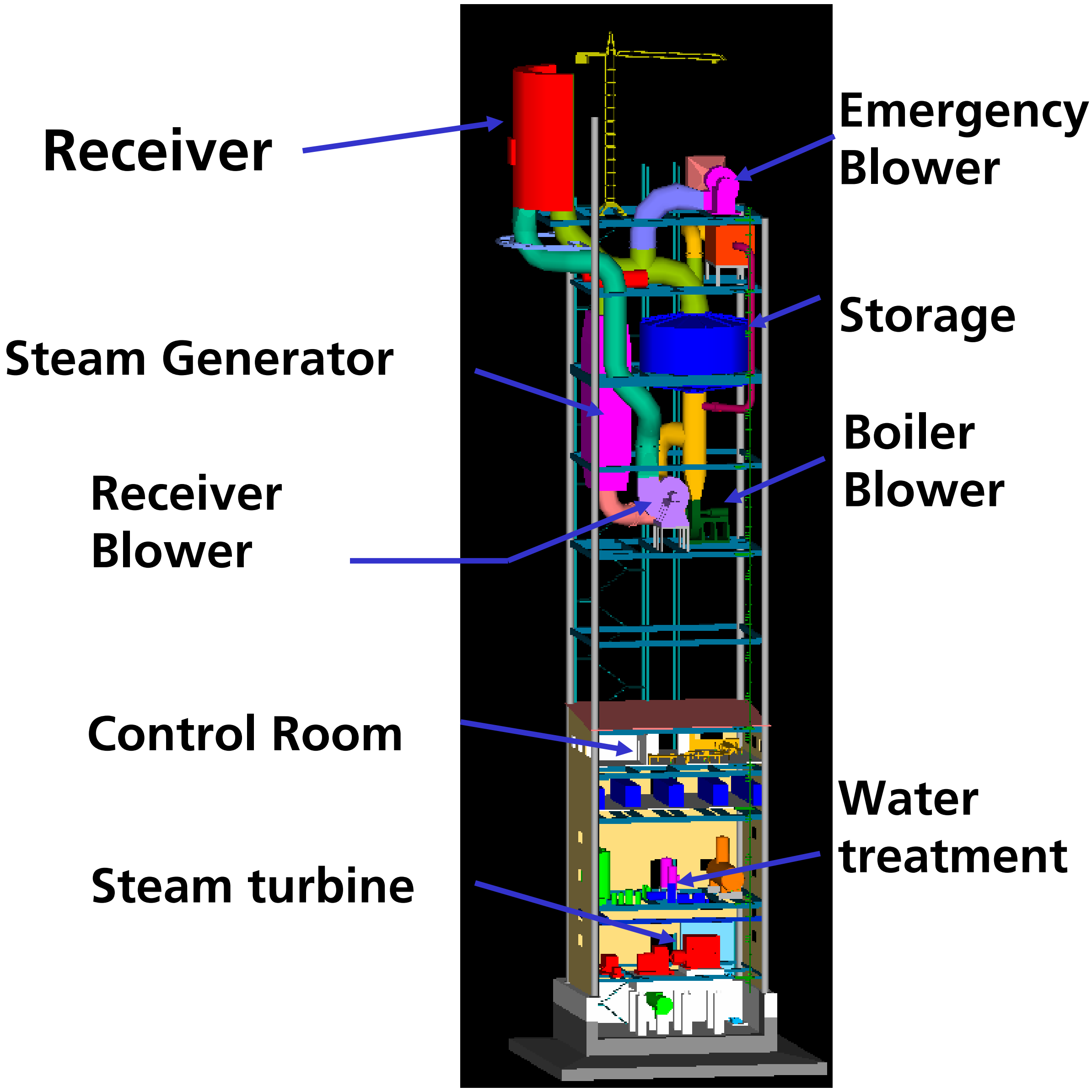


Figure 5-19: Compact design of the tower and receiver + air circuit done by the German company KAM for PS10 Abengoa project.

5.5.2. Costs and Performance of the reference system

The ECOSTAR reference module has been created as a modified version of the PS10 project described in the previous section. Table 5-19 collects the information for the adapted unitary version of ECOSTAR-air plant with SM=1.82, and a 50 MW commercial plant made of five 10-MW units.

Most of input data for the modules, like heliostats, tower, power block and heat storage, have been provided by the company SOLUCAR and based on commercial offers of suppliers. For some key components, the cost has been adapted from the Second Generation Study [15]. Financial scenario, heliostat reflectivity and price, and fuel cost, have been adapted according to ECOSTAR general rules and methodology.

Table 5-19: Base module of 10 MW and multi-tower 50 MW plant of air-cooled receiver tower power system (Input data).

Input data	10 MW unit	5x 10 MW	
site name	Seville	Seville	
Longitude	-5.9	-5.9	°
Latitude	37.2	37.2	°
Solar field			
total reflective area of the solar field	104580	522900	m^2
total area needed for the power plant	0.418	2.092	km^2
area of one heliostat	121.34	121.34	m^2
number of heliostats	862	4309	
mean reflectivity	0.88	0.88	-
Factor for Solar field parasitics	0.0065	0.0065	
design parasitics for pumping and tracking	680	3399	kW
Receiver			
max. air temperature at receiver exit	680	680	°C
design solar thermal input (to receiver)	50669	253345	kW
Power block			
design net electrical output	10000	50000	kW
Factor for power block parasitics	0.030	0.030	
design efficiency of the power block	0.34	0.34	-
mean plant availability	0.96	0.96	
Storage			
storage capacity	3	3	h
thermal capacity of the storage	94233	471166	kWh
storage efficiency	0.95	0.95	-
air temperature at storage discharging	650	650	°C
Efficiency factor due to lower fluid temperature	0.985	0.985	-
O&M Input			
Labor costs per employee	48000	48000	€/a
number of persons (without field maintenance)	30	30	
spec. number of persons for field maintenance	0.03	0.03	$1/1000m^2$
number of persons for field maintenance	3.1	15.7	
Water costs per MWh electricity produced	1.30	1.30	€/MWh
O&M Equipment costs percentage of investment	1%	1%	per a
power block O&M fix	27	27	€/kW
power block O&M variable	2.5	2.5	€/MWh
Overall plant availability	0.96	0.96	

Cost input			
specific investment cost for solar field	150	138	€/m2
spec. investment cost for power block	600	536	€/kW$_e$
spec. investment cost for storage	60	54	€/kWh$_{th}$
spec. investment cost for receiver	115	103	€/kW$_{th}$
spec. land costs	2	2	€/m^2
total investment cost for tower	2 000 000	8 934 538	€
annual insurance cost	0.01	0.01	
Life time	30	30	years
dept interest rate	0.08	0.08	
surcharge for construction, engineering & contingencies	0.20	0.20	

Table 5-19 summarizes the main input data for both the ECOSTAR 10-MW module and the 50 MW plant. Because of the 3-hour heat storage of 94 MWh, the base module represents a significant scaling up versus the original PS10 plant designed by Abengoa with only 20 MWh. Subsequently, the number of heliostats has been significantly increased to 862 and therefore the cost scaled down to 134 €/m^2. Investments required for receiver, tower and storage were supplied by Abengoa and based in commercial offers for PS10. Mature systems like the storage were scaled up from PS10 to ECOSTAR10 using an exponent of 0.6. Less mature systems like the receiver and air circuit were scaled up with an exponent of 0.8. Mass production of heliostats was given an exponent of 0.95.
The second scaling up from ECOSTAR10 to ECOSTAR50 represented a 5-module replication. Again heliostats were given a replication exponent of 0.95. Replication of towers, storage modules, receivers and power blocks were quantified with exponents of 0.93.

Table 5-20: Base module of 10 MW and multi-tower 50 MW plant of air-cooled receiver tower power system (Results)[15].

Economical Results	10 MW unit	5 x 10 MW	
fixed charge rate	0.0988	0.0988	
investment solar field	15 687 000	72 370 471	€
investment power block	6 587 922	29 430 020	€
investment receiver	5 826 936	26 030 491	€
investment tower	2 000 000	8 934 538	€
investment storage	5 653 996	25 257 920	€
investment land	836 640	4 183 200	€
indirect costs	7 673 182	34 825 793	€
sum total equipment costs	36 592 494	166 206 641	€
total investment including indirect costs	43 910 993	199 447 969	€
specific investment	4 391	3 989	€/kW_{el}
annual O&M costs	2 334 800	5 825 666	€
annual financing & insurance costs	4 339 611	19 710 931	€
levelized electricity costs	**0.2342**	**0.1787**	**€/kWh_{el}**

The cost and performance calculation are done for operation according to the load curve (9:00 a.m. to 11 p.m.). Expected LEC for the reference 10-MW module would be 23.42 €/MWh with a projected scaling down to 17.87 €/MWh for replication to 5 modules at the same site.
The annual component performance is presented in Figure 5-20. Solar-to-electric efficiency is estimated to 13.5%, which is considered as quite low for CSP systems. This is due to the relative low receiver performance of current state-of-the-art the volumetric receiver systems, which are less far developed than molten salt or saturated steam receiver technology. Efficiency improvements should, therefore, first concentrate on receiver and air circuit and related parasitics like blowers consumption.
Compared to other systems the cost of the heat storage is also relatively high. This may result from the fact that the costs provided by industry include high additional risk surcharges since the requested sizes are not typical in other applications for the first of its-kind demonstration systems.

[15] Note that absolute cost data for each of the reference systems are on a different level of maturity, so that no direct comparison between costs of different reference systems appears feasible. The numbers may also deviate significantly from project costs of the first commercial plant currently erected in Spain. However the relative distribution of the different cost items and their relative cost reduction potential is considered to be well estimated by this approach.

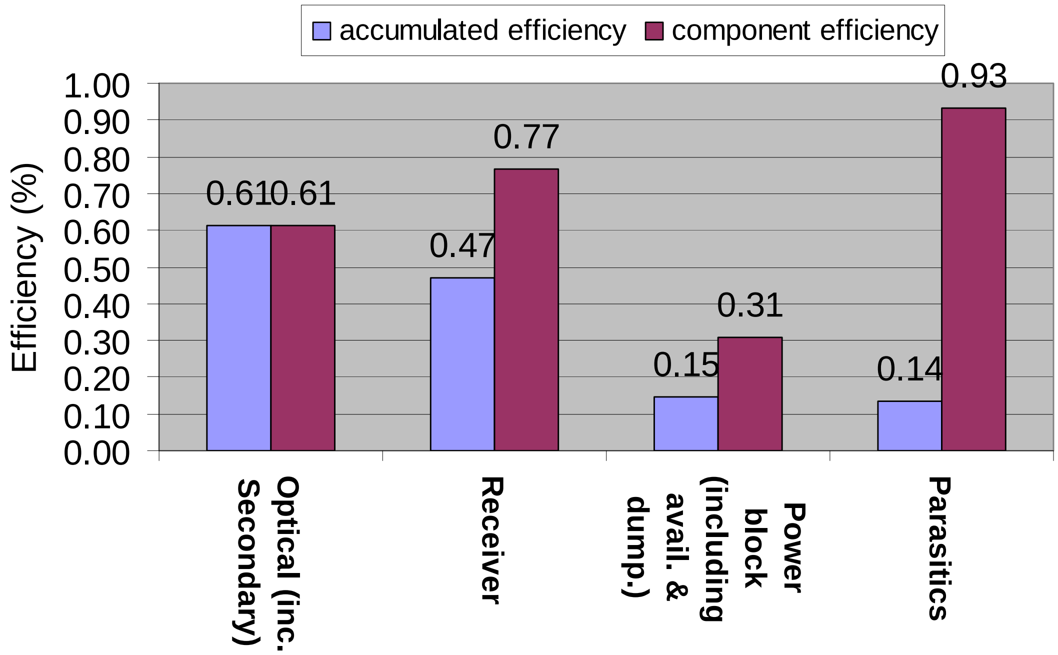


Figure 5-20: Results of annual performance calculation for the reference plant of 50 MW.

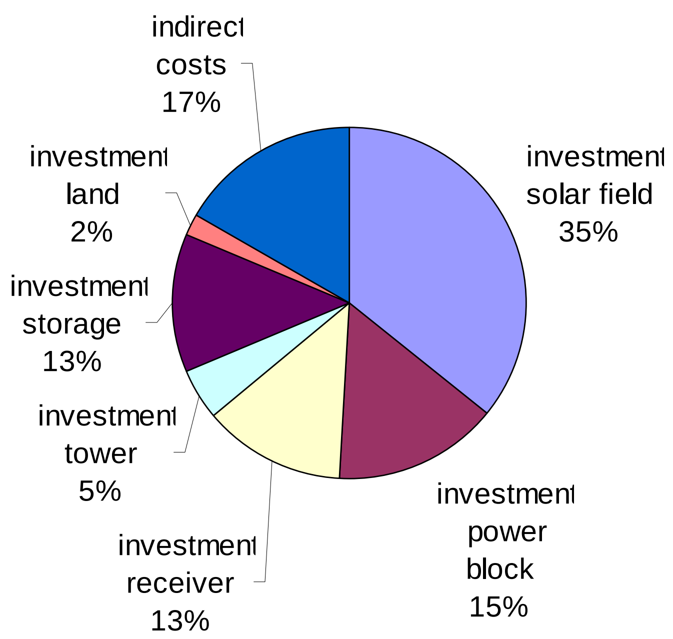


Figure 5-21: Investment breakdown for the reference plant of 50 MW.

5.6. CRS using pressurized air in combination with a solar hybrid gas-turbine

5.6.1. Status of technology

The concept presented in this chapter is a central receiver solar hybrid gas turbine power plant. It is based on the Refos receiver type, which is a pressurised volumetric air receiver. Different than in all other concepts, solar high temperature heat is introduced into a gas-turbine (Figure 5-22). The concept actually needs additional fuel to increase the temperature above the level of solar system. In a later stage of development a solar-only operation at higher receiver outlet temperatures and the use of thermal energy storage can be possible. The motivation for this approach is that high power conversion efficiencies for both solar and fossil input can be achieved. No, or less cooling water is required for cooling purposes and specific investment costs of gas-turbine or combined cycle systems are generally lower than for Rankine cycles. This concept has been investigated recently under the EC contract No. ENK5-CT-200-00333. Partners involved were ORMAT, (Israel) CIEMAT (Spain), DLR (Germany), SOLUCAR (Spain) and TUMA (Switzerland). This project has included experimental investigations of a REFOS system at the Plataforma Solar at Almería, Spain as well as theoretical studies concerning the up scaling of the plant to 16 MW_{el}. In the experimental part of the SOLGATE project a cluster of three receivers with 1 MW_{th} power was integrated into a gas turbine with a design power output of 250 kW. The system was operated in the project for 500h under solar conditions. Most of the information given here are taken from [30] and are referred to the theoretically investigated PGT10 combined cycle system designed for Seville. Beside technical system optimisations through the use of computer simulations the study includes also detailed economical information on this type of power plant. A first pilot plant with a power size of 2 x 200 kW is currently under construction in Italy (see Figure 5-24). Performance and cost information presented here are less mature than for other systems presented in this report, since no pilot plant experience for the considered reference design is yet available. However they appear appropriate to identify most relevant approaches for cost reduction.

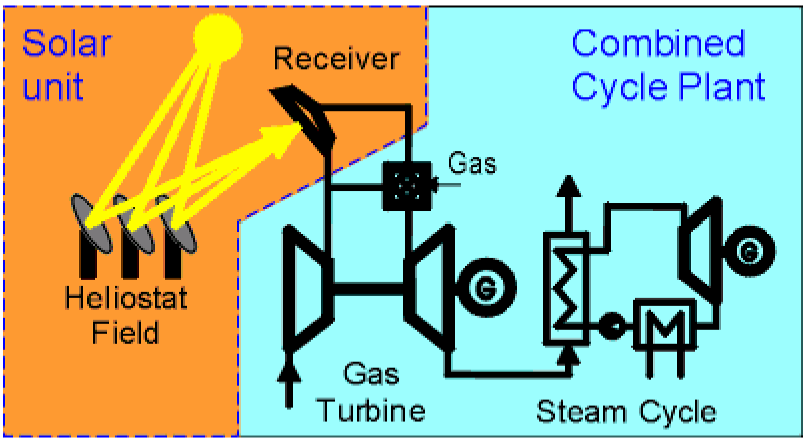


Figure 5-22: Scheme of the SOLGATE power plant concept.

This system consists of a solar field using 343 heliostats and a REFOS receiver with 2 different types of receiver elements. One type is designed for low temperatures up to 600°C, and the second type is designed for temperatures up to 800°C. A modified PGT10 gas turbine from GE Oil&Gas was considered for this system. At design conditions the pressurised air from the compressor of the gas turbine (14.3 bar, 420°C) is fed into the low temperature receiver elements, and heated up to 600°C by solar. Afterwards this air enters the mid-temperature receiver elements and is heated further up to 800°C. The remaining heat required to reach the turbine inlet temperature of 1020°C is provided by natural gas burned in a combustion chamber. After the expansion in the turbine, the gas enters a heat recovery steam generator with 480°C and is used to generate steam for a Rankine cycle. The thermal power input from solar is 18.5 MW at design point. An additionally thermal input from natural gas of 14.4 MW is required at design conditions in order to get an electrical output of 10.8 MW_{el} from the gas turbine generator plus 5 MW_{el} from the bottom cycle. The solar fraction at the design point is 56.8%.

A further increase of the receiver temperature up to 1000°C has been demonstrated at the Plataforma Solar prototype receiver, but doesn't provide sufficient information on cost, durability and performance, so that it was not considered in this study.

Since the SOLGATE system is a hybrid power plant, it is not able to run in solar only mode, but it is able to deliver the design electrical output in pure fossil operation mode. The only limitation of the power output is caused by the strong dependency on ambient temperature which is common for gas turbine cycles.

The reference data of reference [30] is taken from the system layout and the simulation of the plant at Seville with a two-stage receiver and a maximal temperature of 800°C at receiver outlet (Figure 5-23).

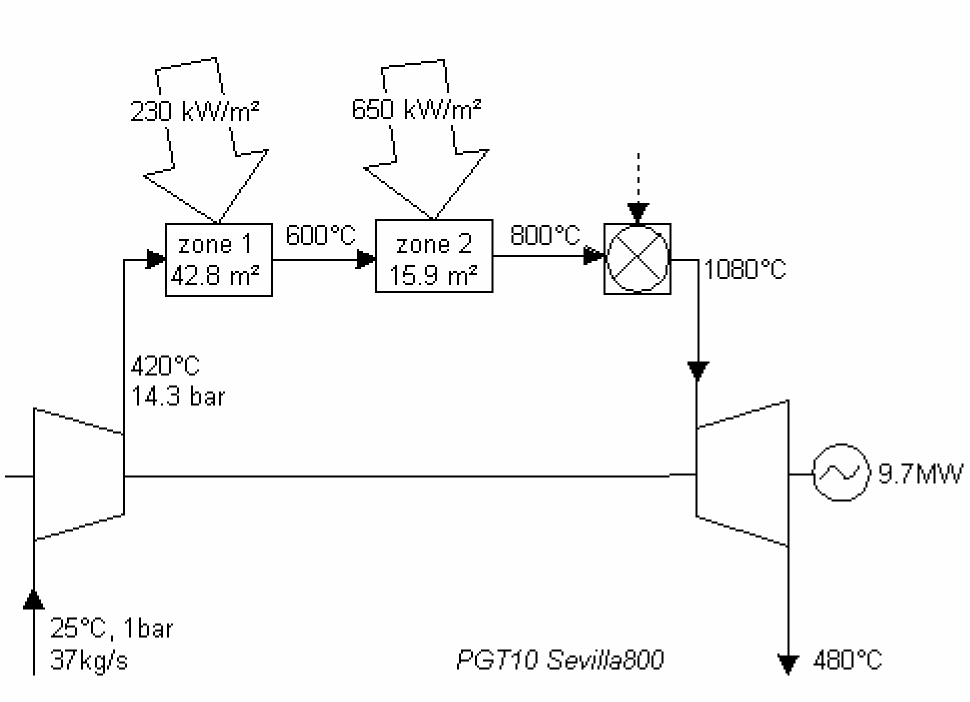


Figure 5-23: Heat flow diagram for the gas turbine part of SOLGATE PGT10 power plant concept

Figure 5-24: Construction site of a solar-hybrid gas-turbine plant in Italy.

5.6.2. Cost and performance of reference system

Based on these reference data, we have designed a power plant for the selected site, load curve and other boundary conditions. Since the reference system has only a power 14.6 MW_{el} we investigate a power park of four equal systems at one site, to account for similar O&M conditions than in the other cases. Specific costs for the power block, receiver, and storage were scaled using an exponent of 0.93 resulting in 90% of the specific costs figures of the original design. Design and cost assumptions are summarized in Table 5-21 and Table 5-22.

Table 5-21: Design data for solar hybrid gas turbine reference system.

Input data	14 MW Plant	4 x 14 MW	
site name	Seville	Seville	
Longitude	-5.9	-5.9	°
Latitude	37.2	37.2	°
Solar Field			
total reflective area of the solar field	38000	152000	m^2
total area needed for the power plant	0.432	1.728	km^2
area of one heliostat	121.34	121.34	m^2
number of heliostats	313	1253	
mean reflectivity	0.88	0.88	
Receiver			
max. air temperature at receiver exit	800	800	°C
design solar thermal input	18 500	74 000	kW
Power cycle			
design solar fraction	0.5631	0.5631	-
design net electrical output	14 683	58 732	kW
design efficiency of the plant	0.447	0.447	-
mean plant availability	0.96	0.96	
O&M Input			
Labor costs per employee	48 000	48 000	€/a
number of persons (without field maintenance)	30	30	
spec. number of persons for field maintenance	0.03	0.03	$1/1000m^2$
number of persons for field maintenance	1.1	4.6	
Water costs per MWh electricity produced	1.00	1.00	€/MWh
O&M Equipment costs percentage of investment	1%	1%	per a
power block O&M fix	27	27	€/kW
power block O&M variable	2.5	2.5	€/MWh

Table 5-22: Cost data for solar hybrid gas turbine reference system.

Cost input	14 MW Plant	4 x 14 MW	
specific investment cost for solar field	150	140	€/m^2
spec. investment cost for power block	700	635	€/kW$_e$
spec. investment cost for storage	50	45	€/kWh$_{th}$
spec. land costs	2	2	€/m^2
total investment cost for tower	2 000 000	7 260 153	€
spec. investment cost for receiver	150	136	€/kW$_{th}$
annual insurance cost	0.01	0.01	
annual O&M costs factor	1.00	1.00	
Life time	30	30	years
dept interest rate	0.08	0.08	
surcharge for construction, engineering & contingencies	0.20	0.20	
fuel costs	15	15	€/MWh

The cost and performance calculations are done for a hybrid operation according to the load curve (9:00 a.m. to 11 p.m.). The annual capacity factor was evaluated to be 55.1%; 19% of the heat was provided by the solar system. If the outlet temperature of the receiver would be increased to 1000°C a solar contribution up to 30% would be feasible (without storage) following this load curve[16]. The calculation yield total investments of 95 Mio.€; Blended LEC at the given fuel price of 15 €/MWh, result in hybrid electricity costs of 8.2 cents€/kWh. 3.0 cents€/kWh of this amount is attributed to fuel costs. When cost of solar and fossil operation are artificially separated to split the generation cost to the solar and fossil part, the solar LEC[17] would be 13.9 cents€/kWh and the fossil LEC 6.9 cents€/kWh.

Hybrid operation would yield on the one hand side a constant and well defined capacity factor (55% in this case), one the other side, it would result in relatively low LEC compared to solar-only operation. However, the boundary conditions in some of today's political frameworks where solar electricity is supported by a feed-in tariff, hybrid operation is not applicable or very much restricted.

The annual component performance is presented in Figure 5-25. Solar to electric efficiency is 19.1%, which is considered to be very high for CSP systems. This is the key motivation to follow this concept, although the technical integration of the receiver into the gas-turbine system is rather complex. Concentrator and receiver performance are based on comprehensive numerical models which have used measured performance figures of individual components. Thus, the uncertainty is still rather high. Parasitic power consumption is included into the power cycle efficiency, since a major parasitic load is produced by the pressure drop of the gas turbine air flow through the receiver between compressor and gas turbine.

The distribution of investment cost is presented in Figure 5-26. The specific investment cost is 1622 €/kW$_e$. Since this number depends strongly on the capacity factor and solar share of the plant it is not considered to be useful for comparisons. Due to the small solar fraction is reflected in the larger share of the power block costs compared to other technologies presented here. Based on the available information cost for engineering and construction are listed separately.

[16] Higher receiver temperature would lead to slightly lower receiver efficiencies; the integration of a thermal energy storage in such a system is rather complex and is evaluated in chapter 7.
[17] taking into account all solar investment and O&M costs and the respective share of the power block O&M and investments

Table 5-23: Economical results for the solar hybrid gas turbine system[18].

Economical Results			
fixed charge rate	0.0988	0.0988	
investment solar field	5 700 000	21 273 152	€
investment power block	10 278 100	37 310 291	€
investment receiver	2 775 000	10 073 463	€
investment tower	2 000 000	7 260 153	€
investment land	864 000	3 456 000	€
indirect costs	4 323 440	15 874 684	€
sum total equipment costs	21 617 199	79 373 419	€
total investment including indirect costs	25 940 639	95 248 103	€
specific investment	1 767	1 622	€/kWh_{el}
annual O&M costs	2 398 645	5 189 437	€
annual financing & insurance costs	2 563 647	9 413 126	€
annual fuel costs	2 156 205	8 624 820	€
levelized electricity costs	0.1004	0.0819	€/kWh_{el}
levelized solar electricity costs	0.1474	0.1385	€/kWh_{el}
levelized fossil electricity costs	0.0704	0.0688	€/kWh_{el}
fuel costs included in fossil LEC	0.0304	0.0304	€/kWh_{el}

[18] Note that absolute cost data for each of the reference systems are on a different level of maturity, so that no direct comparison between costs of different reference systems appears feasible. The numbers may also deviate significantly from project costs of the first commercial plant currently erected in Spain. However the relative distribution of the different cost items and their relative cost reduction potential is considered to be well estimated by this approach.

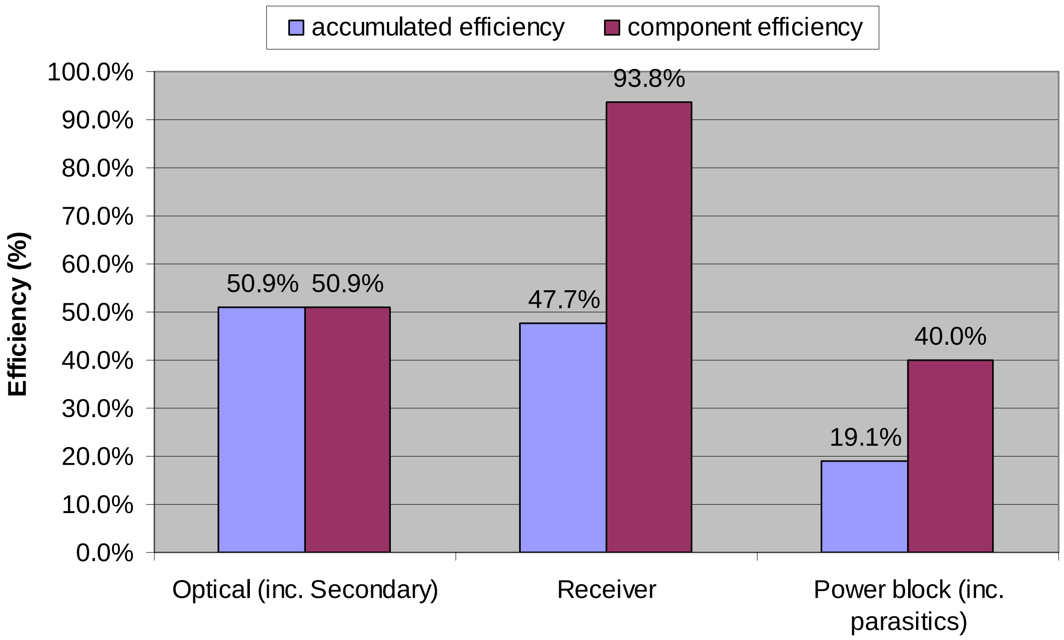


Figure 5-25: Results of annual performance calculation.

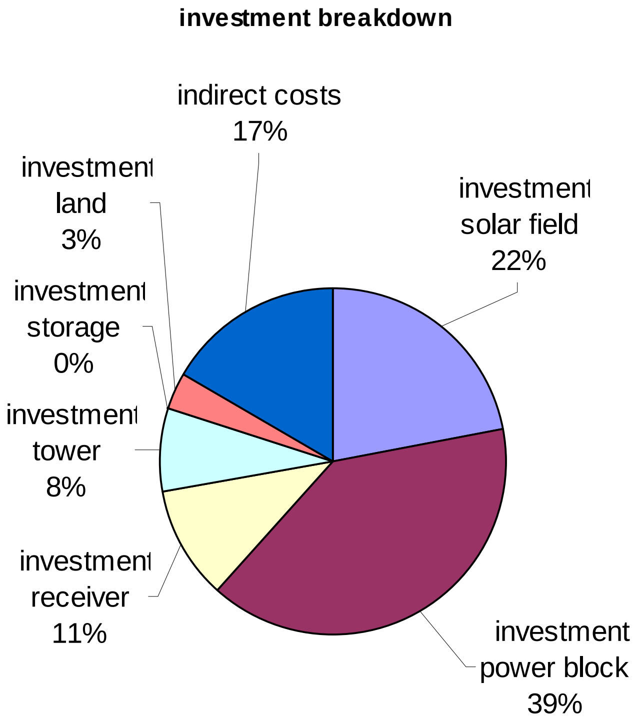


Figure 5-26: Investment breakdown of reference SOLGATE plant.

5.7. Dish-engine systems using Stirling or Brayton cycles

5.7.1. Status of technology

Initially inspired by parabolic dish antennas and the high potential efficiency of Stirling engines, several dish-Stirling systems have been built and tested extensively over the last three decades, while some dish-concentrators where developed for other purposes. Figure 5-27 shows some of these dishes and dish engine systems. Two or more units of each of the four dish/Stirling systems shown in the figure were tested for thousands, or tens of thousand hours. Seven 10 kW EURODISH systems are currently in operation in several countries (Spain, Italy, France, Germany, India). A WGA dish with a SOLO Stirling engine is still running at the Sandia National laboratory. Numerous solar receivers were also designed and tried with the Stirling engines. Standard is a tubular receiver made of high temperature alloys, others like sodium pool-boilers and heat-pipes, or multiple heat-transfer tube arrays have been tested. More recent designs (e.g. the SAIC system) include a fuel combustion option to boost power during periods of insufficient solar input.

Two main showstoppers have so far prevented dish/Stirling commercialization – the dish cost and the lack of a Stirling engine industry, at the appropriate power level for solarization, which is needed to reduce engine production and O&M costs, and increase its reliability. There is so far only one company (SOLO, Germany) that started small series production of Stirling engines, in this case not even for solar but for Cogen applications. The development of a Microturbine industry in the last decade opened the door for gas turbines (Brayton cycle) as possible substitution for the Stirling engine. These small gas turbines (30-100 kW) rely on a mature and extensive industry, with a proven record of high reliability and low production and O&M costs. Their efficiency has been rising steadily due to the recent development of efficient high-temperature recuperators, air bearings, high-speed alternators and ceramic rotors. Proven thermal to electric efficiency is above 30% and thus still lower than that of Stirling engines.

Dish-Stirling overview

The basic module of a dish/Stirling power plant is shown in Figure 5-28; it is made of a parabolic dish concentrator, solar receiver and a Kinematics Stirling engine. Typically the dish reflective area is between 40 to 120m² and the power output of each module is from 10 to 25kW, but as large as 400m² dishes have been made, though there is no matching Stirling engine yet. The plant is made of as many modules as needed to produce the required power. The system is hybrid by nature, using fuel to supplement solar power. When solar energy is unavailable, the system can operate with fuel alone. The solar fraction is therefore a design parameter.

Dish-Brayton overview

The basic module of a dish/Brayton power plant is shown in Figure 5-29; it is made of a parabolic dish concentrator, solar receiver and a recuperated gas turbine. First system design for a possibly interesting prototype size is in the order of 120m² reflective area and a power output of each module of 30kW Since dishes as large as 400m² have been made, bigger and thus already commercialized engines could be interesting to be coupled with these big dishes. The plant can be made of as many modules as needed to produce the required power. The system is hybrid by nature, using fuel to supplement solar power, assuring that the turbine always operates at full capacity. When solar energy is unavailable, the system can operate with fuel alone. The solar fraction is therefore a design parameter.

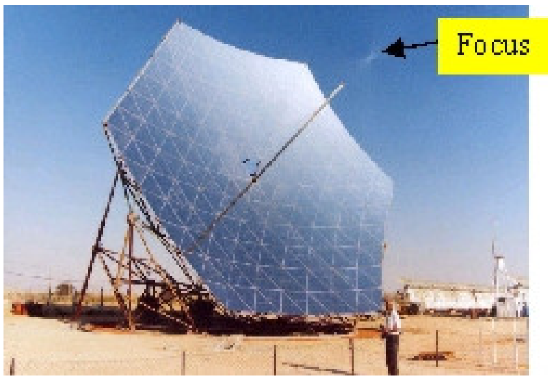
The McDonnell-Douglas dish/Stirling system

The WGAssociates dish/Stirling system

The SAIC dish/Stirling system

The Schlaich Bergermann und Partner dish/Stirling system

HiTek's 14 m^2 dish prototype



The Australia National University 400 m^2 dish

Figure 5-27: Some of the dish systems developed over the past 30 years. The McDonnell-Douglas and WGA technologies are now owned by Stirling Engine Systems (SES)

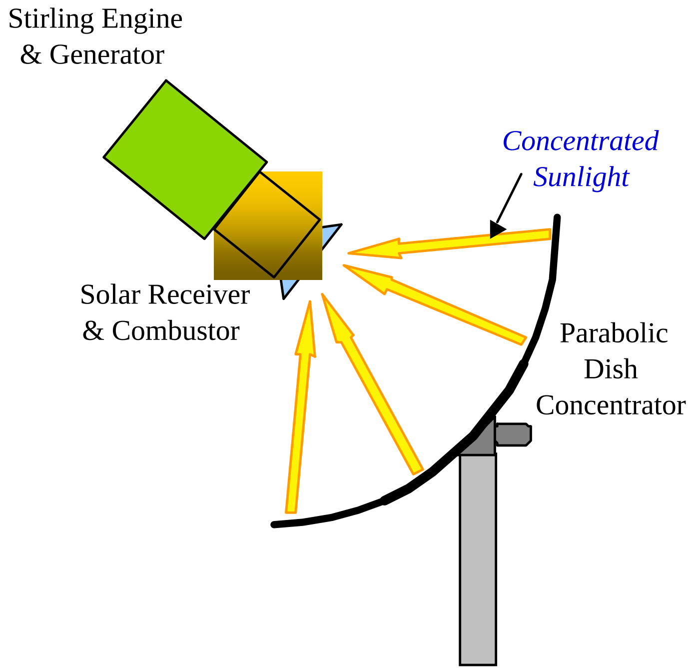


Figure 5-28: Operational scheme of the Dish/Stirling unit

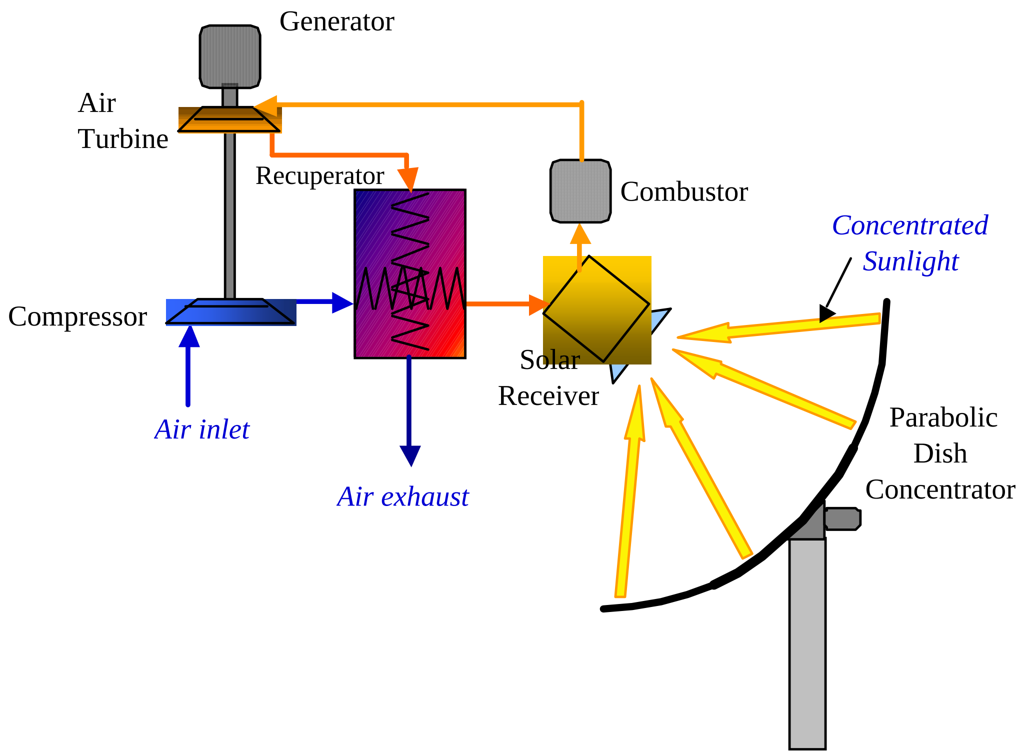


Figure 5-29: Operational scheme of the Dish/Brayton unit

5.7.2. Cost and performance of the reference system

Based on these reference data, we have designed a power plant for the selected site, load curve and other boundary conditions. Since one reference system unit has only a power 22 kW_{el} we investigate a power park of many equal systems at one site, to account for similar O&M conditions than in the other cases. Design and cost assumptions are summarized in Table 5-24 and Table 5-25.

Table 5-24: Design data for the dish/stirling reference system.

Input data	50 MW Plant	
site name	Seville	
Longitude	-5.9	°
Latitude	37.2	°
Solar Field		
total reflective area of the solar field	350000	m^2
total area needed for the power plant	1.4	km^2
area of one dish	120.4	m^2
number of dishes	2907	
mean reflectivity	0.88	
Receiver		
max. hydrogen temperature at receiver exit	800	°C
design solar thermal input	233125	kW
Power cycle		
design solar fraction	1.0	-
design net electrical output	50000	kW
design efficiency of the plant	0.2145	-
mean plant availability	0.90	
O&M Input		
Labor costs per employee	48 000	€/a
number of persons (without field maintenance)	30	
spec. number of persons for field maintenance	0.060	$1/1000m^2$
number of persons for field maintenance	21	
O&M Equipment costs percentage of investment	1.5	% per a
power block O&M fix	40	€/kW
power block O&M variable	4.5	€/MWh

Table 5-25: Cost data for the dish/stirling reference system.

Cost input	50 MW Plant	
specific investment cost for solar field	440	€/m^2
spec. investment cost for power block	3000	€/kW$_e$
spec. land costs	2	€/m^2
spec. investment cost for receiver	120	€/kW$_{th}$
annual insurance cost	0.01	
Life time	30	years
dept interest rate	0.08	
surcharge for construction, engineering & contingencies	0.20	
fuel costs	15	€/MWh

The cost and performance calculations are done for a hybrid operation according to the load curve (9:00 a.m. to 11 p.m.). The annual capacity factor was evaluated to be 49.6%; 45% of the heat was provided by the solar system. The calculation yield total investments of 401 Mio.€; Blended LEC at the given fuel price of 15 €/MWh, result in hybrid electricity costs of 28.11 cents€/kWh. 4.6 cents€/kWh of this amount is attributed to fuel costs. When cost of solar and fossil operation are artificially separated to split the generation cost to the solar and fossil part, the solar LEC would be 38.4 cents€/kWh and the fossil LEC 19.7 cents€/kWh.
Hybrid operation would yield on the one hand side a constant and well defined capacity factor (50% in this case), one the other side, it would result in relatively low LEC compared to solar-only operation. However, the boundary conditions in some of today's political frameworks where solar electricity is supported by a feed-in tariff, hybrid operation is not applicable or very much restricted.
The annual component performance is presented in Figure 5-30. Solar to electric efficiency is 16.7%.
The distribution of investment cost is presented in Figure 5-31. The specific investment cost is 8035 €/kW$_e$. Since this number depends strongly on the number of produced units, the capacity factor and solar share of the plant it is not considered to be useful for comparisons.
Compared to the other reference systems considered in this study, a dish plant providing 50MW capacity, consists of a huge number of single units (2900). This would presumably lead to considerably cost reduction because it requires a mass production of dish/stirling systems in a magnitude quit comparable to the heliostat production for the 50 MW CRS systems. However, such a mass production would not represent the state-of-the-art of the dish/stirling technology and therefore is treated as innovation in chapter 6.

Table 5-26: Cost data for the dish/stirling reference system.[19]

Economical Results		
fixed charge rate	0.0988	
investment solar field	154 000 000	€
investment power block	150 000 000	€
investment receiver	27 975 000	€
investment land	2 800 000	€
indirect costs	66 955 000	€
sum total equipment costs	334 775 000	€
total investment including indirect costs	401 730 000	€
specific investment	8035	€/kW$_{el}$
annual O&M costs	11 451 238	€
annual financing & insurance costs	39 701945	€
annual fuel costs	9 893 639	€
levelized electricity costs	0.2811	€/kWh$_{el}$
levelized solar electricity costs	0.3835	€/kWh$_{el}$
levelized fossil electricity costs	0.1974	€/kWh$_{el}$
fuel costs included in fossil LEC	0.0456	€/kWh$_{el}$

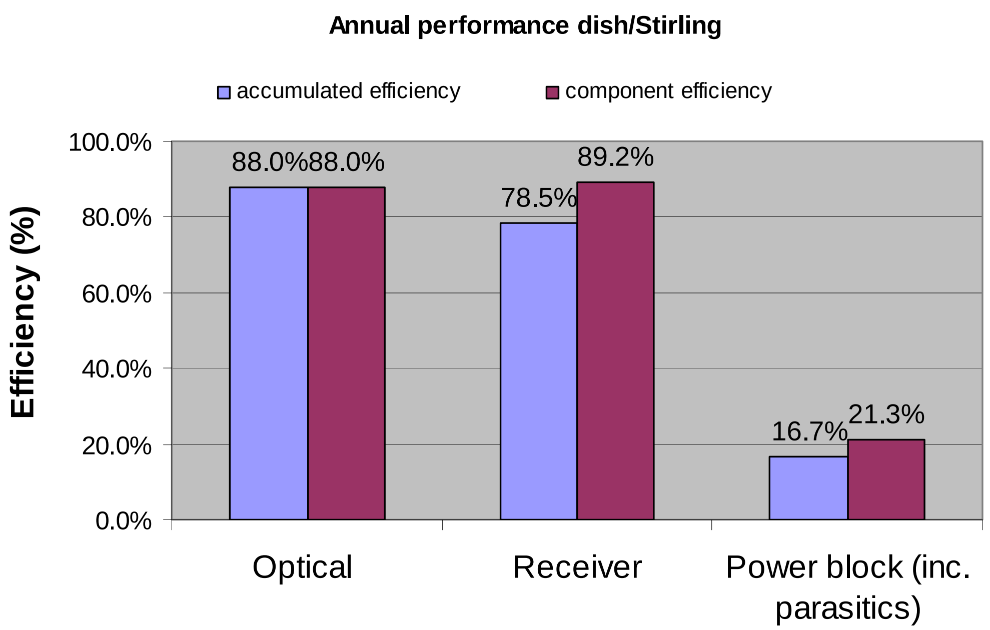


Figure 5-30: Results of annual performance calculation.

[19] Please note that absolute cost data for each of the reference systems are on a different level of maturity, so that no direct comparison between costs of different reference systems appears feasible. The numbers may also deviate significantly from project costs of the first commercial plant currently erected in Spain. However the relative distribution of the different cost items and their relative cost reduction potential is considered to be well estimated by this approach.

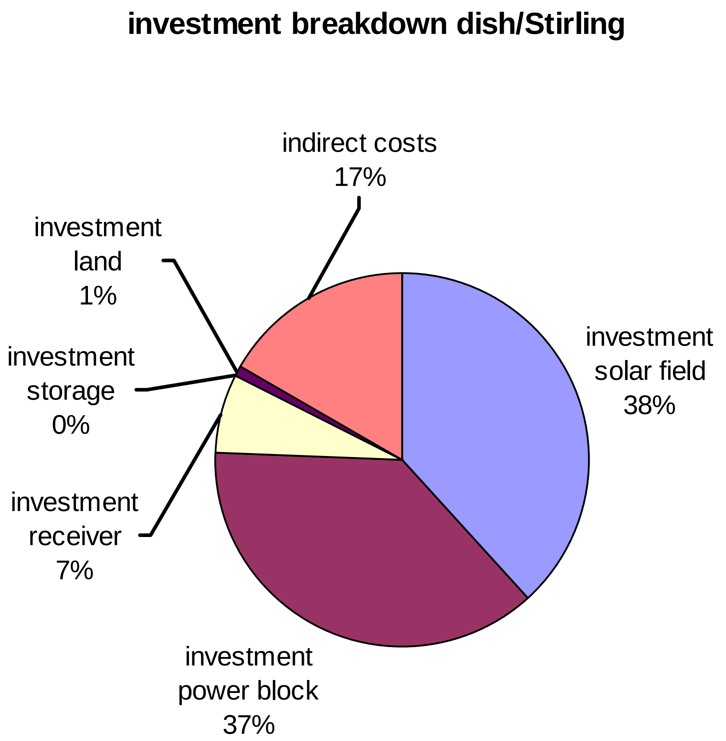


Figure 5-31: Investment breakdown of reference dish/Stirling plant.

6. Technical innovations analysed

The main technical improvements investigated are grouped into three major categories:

- **Concentrators** (including Mirrors)
- **Thermal Energy Storage**
- **Receivers/Absorber and Cycles** (including Heat Collection Elements (HCE) and Power Block).

Technical innovations that reduce costs by improving plant efficiency or reducing initial capital costs are evaluated with respect to probability of the improvement and estimated magnitude of cost reduction. Further the performance potential uncertainties and development risks are analyzed.

6.1. Concentrators

Heliostats are used as concentrators used in Solar Central Receiver Systems. A generic heliostat cost breakdown [1] is shown in Figure 6-1. The major part of the costs are regarding to control and tracking (14% and 30%), the reflector (36%) and the structure (20%), as the technical components of the concentrators.

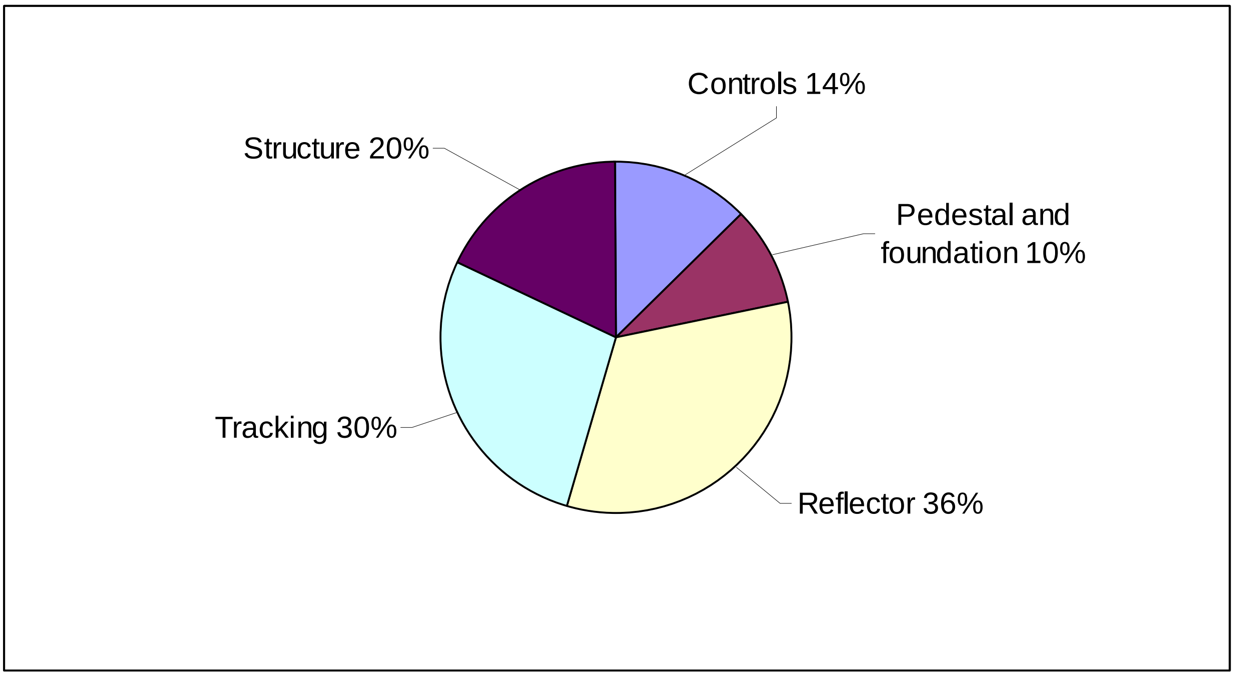


Figure 6-1: Cost breakdown for single heliostat.

For troughs (SEGS), the cost breakdown is shown in Figure 6-2. As the receiver is part of the trough the structure (22.5%) and the mirrors (19.1%) are the main cost-intensive components of the trough systems.

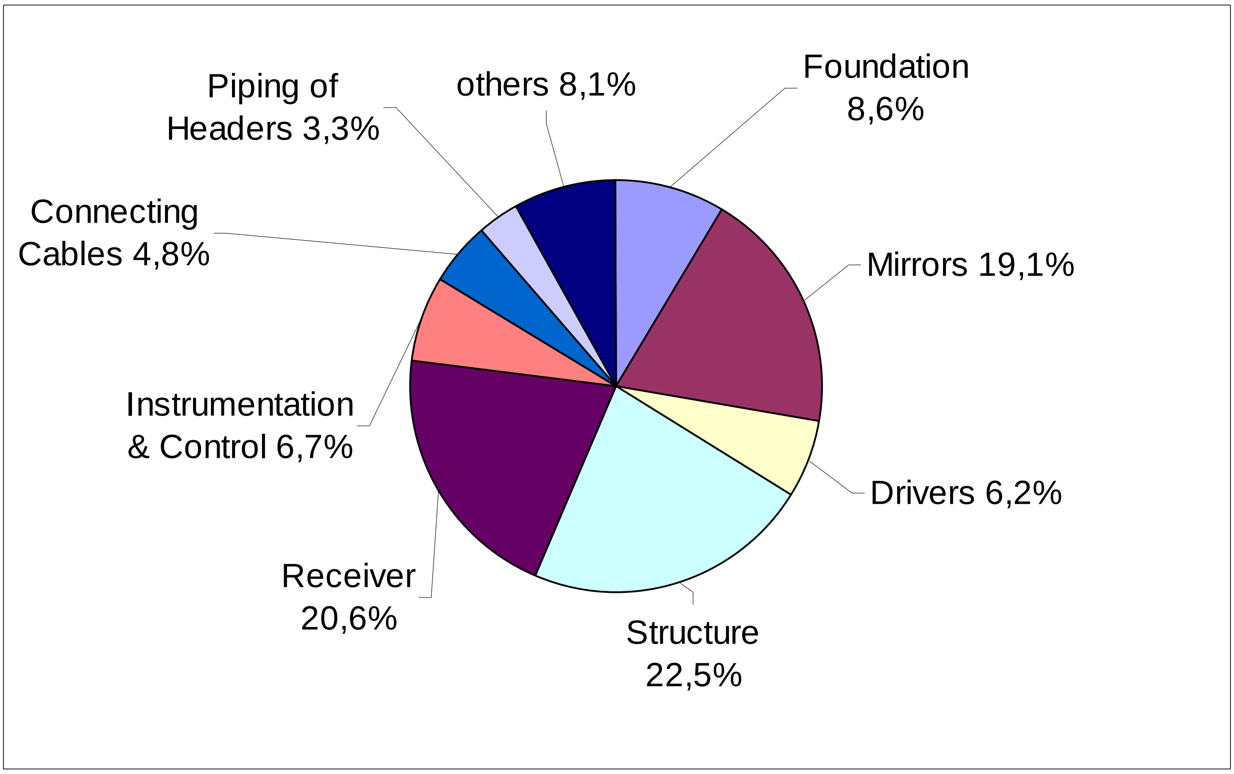


Figure 6-2: Cost breakdown for troughs (SEGS).

The technical improvement of solar concentrators is subdivided based on the innovative impact of:

- Reflector
- Structure
- Control / Tracking.

6.1.1. Reflector (Mirrors)

For all reference systems the technical improvement of the reflectors are essential to reduce the costs of CSP.
State-of-the-art for parabolic trough technology is the currently operating reflector of 4-mm low-iron float glass mirrors used by the SEGS plants in the Mojave Desert in California. Within this chapter the quality of the mirrors is described by a factor which implies not only their reflectivity, but also the availability, the cleanliness, etc..
To increase the reflectivity (> 0.935, AM-1.5) of the optical surface (s. Innovation Report *Concentrators:* 5. Front surface mirrors, 6. Dust repellent mirrors) improvements are possible by:

- Using thin low-iron glass back-silvered mirrors. For parabolic troughs it is necessary to temper the glass to get the needed curvature, but this process is at the moment very expensive and needs further improvement.
- Using front-surface mirrors coated with flexible substrates. Up-to-date resistance under environmental conditions (outdoor durability) are limited.
- Using dust repellent mirrors to improve the cleanliness of the mirrors. Cleanliness requires new materials and significant enhancement in cleaning equipment and methods.

Also cost reductions due to cheaper manufacturing processes of float glass mirrors are conceivable.

New materials should fulfil the following requisites:

- good outdoor durability,
- high solar reflectivity (>92%) for wave lengths within the range: 300 nm - 2500 nm,
- good mechanical resistance to withstand periodical washing,
- low soiling coefficient (<0.15%, similar to that of the back-silvered glass mirrors).

Also the size and geometry of the optical surface influences the costs. Nowadays heliostats up to a size of 150 m² are the commercial reference for CRS.

The so-called Megahelio concept emerges as a very-large-area heliostat concept above 200 m² with the target of 30% cost reduction within less than 5 years time for full development and commercial implementation.

Hexahelium is a combination of enlarging the size of the reflective area above 200 m² and improving the tracking concept (s. below). The expected cost reduction is in a range between 30% and 60%. In 5 to 10 years full development and commercial implementation is required, components are expected to be available before.

Instead of the parabolic geometry Fresnel shaped mirrors are imaginable for the trough technology as well. The main advantages of the Linear Fresnel collector, compared to trough collectors are:

- inexpensive planar mirrors and simple tracking system
- fixed absorber tube with no need for flexible high pressure joints
- no vacuum technology and no metal glass sealing
- one absorber tube with no need for thermal expansion bows
- due to the planarity of the reflector, wind loads are substantially reduced so the reflector width for one absorber tube can easily be three times the width of parabolic troughs
- due to direct steam generation no heat exchanger is necessary
- efficient use of land since the collectors can be placed one next to the other.

One mayor disadvantage of Fresnel shaped mirrors is the notable reduction of the efficiency of 30-40%, which has to be compensated by the lower investment cost. Therefore we have to keep in mind that the cost reduction of about 30-40% for the solar field compared to parabolic troughs takes are needed place with a reduction of efficiency. Cost reduction due to economy of scale and due to an optimal design of the collector will further reduce the investment costs for the solar field. In addition to the cost reduction in the solar field, there are considerable savings offered by lower operation and maintenance costs. Realistic cost targets for the collector are as low as 120 €/m²-.

6.1.2. Structure

The supporting structure of the concentrators also needs improvement. New structures should fulfil the following requisites:

- Lower weight
- Better tracking

The research to improve the supporting structure is mainly integrated in the development of the reflectors as described before and the development of the control and tracking as described in the next chapter.

The concept of Megahelio is a large aspect ratio (≈ 2), preserving similar height than 100 m² units and similar elevation loads, abatement is close to the ground, two pedestals distribute support and motion (for azimuthally turning around one point and moving the other one). A cost reduction of up to 30% is expected.

6.1.3. Control / Tracking

Drive mechanisms of heliostat

Today heliostats are usually mounted on single pedestals and each heliostat, with about 100 to 150 m² of reflective area, is tracked by two single drives in order to adjust it in azimuth

and elevation angle. This adjustment facilitates the redirection of the sun rays onto a fixed receiver for all sun positions above the horizon. More than 40% of the total investment is related to control and tracking of the heliostat system (s. Figure 6-1).
Within Ganged Heliostat the mechanical coupling is reduced to the number of drivers (e.g. by wires). In general there is an antagonistic dependency between optical accuracy and mechanical complexity and an optimum design must be found. Uncertainties and risks in the development of Ganged Heliostats are expected to be high.
The tracking concept of the Hexahelium (see 6.1.1.) belongs to a hexapod mechanism with hydraulic actuators and a new controlling system to have a highly accurate tracking.
Autonomous Heliostats allow removing all the electrical cables, trenches and related components. The main autonomous heliostat field advantages compared on conventional heliostats field are the follow:

- Very low infrastructure cost by elimination of trenches, cables, and electric elements.
- Immunity to lightning damages and rat actions.
- Each heliostat has an Uninterrupted Power Unit and it will not depend on conventional power supply.
- Use of incremental encoders with the advantages of absolute ones (it does not loose the position). The field will continue in operation when software or electric breakdowns happen.
- Increase of field size will be very easy.
- The operational limits due to wind restriction could be supervised by each heliostat.

The development of Autonomous Heliostat will take less than 5 years, the potential of cost reduction is expected to be between 30%and 60% and all with a low to medium level of uncertainty and risk.
New mechanisms should fulfil the following requisites:

- high tracking accuracy
- simple controlling and operation

An overview of the detected innovations for concentrators is given in Table 6-1. It will figure the feasibility to implement the innovations. And will help to select techniques to be supported for further research.

6.1.4. Summary

The detected innovations covered in this Investigation for the concentrators are combined for the LEC calculation and the change of it due to improvements. The mayor fields are:

- ganged heliostats,
- Linear fresnel systems,
- large area heliostats,
- thin glass mirrors / front surface mirrors,
- dust repellent mirrors,
- autonomous heliostats.

The following table should specify a feeling for the ranking of innovations impact on time, cost reduction and risk.

Table 6-1: Summary of technical Innovations for Concentrators.

Innovation class		Linear Fresnel Collector	Ganged Heliostats	Megahelio	Hexahelium	Front surface mirrors (troughs)	Dust repellent mirrors	Autonomous heliostats
Maturity in terms of	durability and robustness	Medium	Medium	Medium	High	Medium	Low	High
	Performance/efficiency	Medium	Medium	Medium	High	Medium	Low	High
Time required for full development and commercial implementation (High: More than 10 years, Medium: 5-10 years, Low: Less than 5 years)		Medium	Medium	Low	Medium	Medium	High	Low
Cost figures dependence on	mass production	High	High	High	High	High	High	High
	Spares/components replacement	Medium	Medium	Low	Low	Low	Low	Low
	Technological breakthroughs during development phase	High	High	Medium	Medium	High	High	Low
	further scaling-up (power, size)	Medium	Medium	Low	Low	Medium	Low	Low
Potential of cost reduction (compared to today’s figures) High: More than 60%, Medium: More than 30%, Low: Less than 30%		Medium	Medium	Low	Medium	Medium	Low	Medium
Uncertainty	Technical / efficiency	High	High	Low	Medium	Medium	Medium	Low
	Economical	High	High	Low	Medium	Medium	High	Low
	Operational	High	High	Medium	Medium	Medium	Low	Medium
Risk	Technical / efficiency	High	High	Medium	Medium	High	Medium	Medium
	Economical	High	High	Low	Medium	Medium	High	Low
	Operational	High	High	Medium	Medium	Medium	Low	Medium

6.2. Storage

The kind of storage system used for solar energy storage depends on the CSP technology. Therefore the analysis of technical innovations for the storage of solar energy is based on the technologies of the CSP reference systems described in chapter 1.
The identified innovations are subdivided into 5 parts:

- Molten salt storage and Room Temperature Ionic Liquids (RTILs)
- Concrete Storage
- Phase Changing Materials (PCM)
- Storage using solid materials
- Storage for saturated water/steam

6.2.1. Molten salt storage and RTILs

State of the art is the 2-tank molten salt storage tested in the Solar Two demonstration project in combination with a Central Receiver Solar Power Plant using solar salt as heat transfer fluid. This 2-tank molten salt storage was also proposed for parabolic trough solar power plants with synthetic oil as heat transfer fluid. Therefore it is necessary to have a heat exchanger for the heat transfer from oil to salt. Otherwise molten salt has to be used as heat transfer medium.
Pacheco et al. [31] published experimental results and theoretical investigations on the usage of a thermocline molten salt storage with a filler material in a parabolic trough power plant. The general idea is to reduce costs through the replacement of expensive salt by cheaper materials. The authors are nominating a cost reduction of about one third compared to a 2-tank molten salt storage. Therefore the 1-tank thermocline storage for parabolic trough plants the selection of a durable filler material and the optimization of charging and discharging methods and devices are the main items. The development risk for them is low. And in short term the technology is able to be implemented.
The usage of new storage materials, so called room temperature ionic liquids (RTILs), may overcome this general drawback since these materials are liquid even at low temperatures. RTILs are organic salts with negligible vapor pressure in the relevant temperature range and a melting temperature below 25°C [32]. Room temperature ionic liquids are quite new materials and it is rather uncertain, whether they are stable up to the temperature level required for CSP and also whether they may be produced at reasonable costs [33].

6.2.2. Concrete storage

The concept of using concrete or castable ceramics to store sensible heat in parabolic trough power plants with synthetic oil as heat transfer fluid (HTF) has been investigated in the WESPE] project ("Mid-term storage concepts – further development of solid media storage") and is continued in the WANDA project.
Since the steel tube register inside the storage material are rather expensive, a tubeless storage could lead to lower specific costs, but there are still some investigations needed for this design. The costs for the tubing make about 45-55% of the total storage costs.
Advanced charging/discharging modes need additional investment in tubes and valves, but they may considerably increase the storage capacity for a given size and material. The basic idea of modular storage charging and discharging is to increase storage capacity by raising the temperature variation between both operating modes. Computer simulations from [34] showed that the capacity of a given storage size could be increased by about 200% compared to the base case operation.
The implementation of a concrete storage system can be realized within less than 5 years. The uncertainties and risks are for both cases (with or without tubes) in a medium range. And in addition the charging/discharging modes are promisingly.

6.2.3. Storage with Phase Change Materials (PCM)

Phase change materials (PCM) are potential candidates for latent heat storage, which is of particular importance for systems which have to deal with large fractions of latent heat, such as direct steam generating systems. PCM storages are not restricted to the solid-liquid transition, they could also use solid-solid or liquid-vapor transition, but actually the solid-liquid transition has some advantages compared to the other phase transitions. At present, two principle measures are investigated:

- encapsulation of small amounts of PCM
- embedding of PCM in a matrix made of another solid material with high heat conduction.

The first measure is based on the reduction of distances inside the PCM and the second one uses the enhancement of heat conduction by other materials.

Storages based on PCM are in an early stage of development and many of the proposed systems are only theoretical or laboratory scale experimental work. Therefore cost estimation is difficult, but the cost target is to stay below **20 €/kWh** based on the thermal capacity.

Even the uncertainties and risks of the PCM storage technology is in a medium range the technology time required for full development and commercial implementation is more than 10 years.

6.2.4. Storage for air receivers using solid materials

Storage types using solid material for sensible heat are normally used together with volumetric atmospheric or pressurized air systems.

The heat has to be transferred to another medium, which may be any kind of solid with high density and heat capacity. Other parameters for a solid material storage are size and shape of the solids which may be chosen in order to minimize pressure loss (high pressure loss causes high parasitic).

Beside fixed solid material as storage medium a new concept using silica sand as intermediate heat transfer medium was developed by DLR to avoid the disadvantages of storage vessels filed with fixed solid material in CSR with open volumetric air technology.

The fixed solid storage medium technology is realizable within a shorter term (less than 5 years) than the moving solid storage medium technology also the uncertainties and risks are in a medium range for solid medium and in a high range for the moving storage material system.

Another innovation is to develop for pressurized closed air receivers a storage container that has to be pressure resistant up to about 16–20 bar depending on the gas turbine pressure ratio. The receiver and the solar field for such a system would be able to deliver thermal power in excess to the power needed by the gas turbine during high insolation periods. This excess power is utilized to charge the thermal storage using a second air cycle driven by an additional blower. In the discharging mode, during non sunshine hours, the receiver is bypassed and the flow direction through the storage is reversed. In addition it would be possible to split up the compressor air flow during low insolation periods, in order to use thermal energy from the receiver and from the storage. For this case the time for development and implementation is between 5 to 10 year and the risks and uncertainties are in a medium range.

6.2.5. Storage for saturated water/steam

In principle the steam drum, which is a common part in many steam generators, is a certain kind of storage because it contains an amount of pressurized boiling water. Steam could be produced from this component solely be lowering the pressure. This storage type has been build several times as process heat storage in industries. The main problem is the size of the steam vessel for larger storage capacity and the degradation of steam quality during discharging.

This storage type is ideal as buffer storage for short time periods of several minutes, to compensate shading of the solar field by fast moving small clouds.
Within a short term of development and commercial implementation the potential for cost reduction is 30 to 60% with low risk and uncertainty.
Using appropriate encapsulated PCM inside the storage could enhance the storage capacity because the latent heat content can be used to slow down the temperature and pressure decrease. They enable smaller storage vessels for the same thermal capacity. The time for full development and commercial implementation using encapsulated PCM for to storage saturated water/steam is estimated in medium range (5-10 years). Uncertainties, risks and potential of cost reduction are also located in the medium range.

6.2.6. Summary

The storage systems are normally especial solutions for the particular Concentrating Solar Power plant type. The given tables show how long the developments will still last and the expected impact of them.

Table 6-2: Summary of technical Innovations for Storage Systems (part 1).

Innovation class		molten salt			RTIL	concrete storage	
Specific type		2-tank	1-tank thermocline	2-tank	tube type	tubeless	advanced charging/ discharging
CSP plant type		Tower / trough	Trough	trough	Trough		
Maturity in terms of	durability and robustness	High	Medium	High	Low	Medium	High
	Performance/efficiency	High	Medium	High	Low	Medium	High
Time required for full development and commercial implementation (High: More than 10 years, Medium: 5-10 years, Low: Less than 5 years)		Low	Medium	Low	High	Medium	Medium
Cost figures dependence on	mass production	Medium	Medium	Medium	High	Medium	Medium
	Spares/components replacement	Low	Low	Medium	Low	Medium	Medium
	technological breakthroughs during development phase	Low	Low	Low	Low	Medium	Medium
	Further scaling-up (power, size)	Medium	Medium	Medium	Low	Medium	Medium
Potential of cost reduction (compared to today's figures) High: More than 60%, Medium: More than 30%, Low: Less than 30%		Low	Medium	Low	Medium	High	Medium
Uncertainty	technical/efficiency	Low	Medium	Medium	High	Medium	Medium
	Economical	Low	Medium	Medium	High	Medium	Medium
	Operational	Medium	Medium	Medium	High	Medium	Medium
Risk	technical/efficiency	Medium	Medium	Medium	High	Medium	Medium
	Economical	Medium	Medium	Medium	High	Medium	Medium
	Operational	Medium	Medium	Medium	Low	Medium	Medium

Table 6-3: Summary of technical Innovations for Storage Systems (part 2).

Innovation class		PCM storage	storage using solid material			steam drum	
Specific type		all types	fixed solids	Mobile solids	fixed solids and pressure vessel	saturated water	saturated water + PCM
CSP plant type		Tower / trough	tower			Tower / trough	
Maturity in terms of	durability and robustness	Medium	High	Medium	High	High	Medium
	Performance/efficiency	Medium	Medium	Medium	Medium	Low	Low
Time required for full development and commercial implementation (High: More than 10 years, Medium: 5-10 years, Low: Less than 5 years)		High	Low	Medium	High	Low	Medium
Cost figures dependence on	mass production	Medium	Medium	Medium	Medium	Medium	Medium
	Spares/components replacement	Medium	Medium	Medium	Medium	Medium	Medium
	technological breakthroughs during development phase	High	Medium	High	Medium	Low	High
	Further scaling-up (power, size)	Medium	Medium	Medium	Medium	Low	Medium
Potential of cost reduction (compared to today's figures) High: More than 60%, Medium: More than 30%, Low: Less than 30%		Medium	Medium	Medium	Medium	Medium	Medium
Uncertainty	technical/efficiency	Medium	Medium	High	High	Low	Medium
	Economical	Medium	Medium	High	High	Low	Medium
	Operational	Medium	Low	High	High	Low	Medium
Risk	technical/efficiency	Medium	Medium	High	High	Low	Medium
	Economical	Medium	Medium	High	High	Low	Medium
	Operational	Medium	Low	High	High	Low	Medium

6.3. Receivers/Absorber and Cycles (including Heat Collection Elements (HCE) and Power Block)

The listed innovations are required for achieving the assumed performance for the analyzed systems and to improve the system performances. The innovations are detailed by the reference systems.

6.3.1. Parabolic trough technology using thermal oil as heat transfer fluid

The impact of the innovations for this system is mainly caused by improvements of the absorber tubes. Enhancing the selective coating and the tube joints lead to higher process temperatures and higher pressure levels (reduced pressure drops). The receiver improvements require innovations of the cycle like adding reheat stages or using organic Rankine turbines. All technical innovations improve the power output level.

Table 6-4: Innovations for the reference system: Parabolic Trough using thermal oil as heat transfer fluid.

			Potential Technological Benefits	**Potential Economical Benefits**
Receiver innovations	1	Advance Coating (higher temperature)	Improve receiver performance and longevity	O&M reduction; assembly and installation cost reduction; some component cost reduction
	2	Eliminate bellows		
	3	Increase working temperature		
	4	Improve tube joints		
	5	Increase pressure		
	6	Reduce pressure drop & pipe length		
	7	Improve working fluid		
Cycle Innovations	1	Increase superheated steam temperature	Increase system efficiency	System installed cost and LEC reduction
	2	Add reheat stages		
	3	Use Organic Rankine turbine (for small system)		

6.3.2. Parabolic trough technology using water/steam as heat transfer fluid

For this system all improvements described before are relevant, too.
In addition further development to reduce asymmetric and instability effects in the receiver tubes progress the technology. Also the direct superheating of the steam increases the efficiency. Taking into consideration the experience gathered at the PSA with the DISS test facility and the development of advanced selective coatings for DSDG absorber pipes, 450ºC seems to be a feasible temperature limit for direct steam superheating. Higher temperatures would significantly increase the thermal losses and would reduce the absorber pipes durability.

Table 6-5: Innovations for the reference system: Parabolic trough technology using water/steam as heat transfer fluid.

			Potential Technological Benefits	Potential Economical Benefits
Receiver innovations	1	Advance Coating (higher temperature)	Improve receiver performance and longevity	O&M reduction; assembly and installation cost reduction; some component cost reduction
	2	Eliminate bellows		
	3	Increase working temperature		
	4	Improve tube joints		
	5	Increase pressure		
	6	Reduce pressure drop & pipe length		
	7	Further development to eliminate asymmetric & instability effects in receiver DSG tube		
Cycle Innovations	1	Increase working temperature	Increase system efficiency	System installed cost and LEC reduction
	2	Superheat the steam		
	3	Add reheat stages		

6.3.3. *CRS using molten salt as HTF*

As well as described for the trough systems the homogeneity of the heat transfer fluid is important to increase the efficiency of the system. Also the working temperature is necessary to be maximized. Therefore several possible innovations are listed below.

Table 6-6: Innovations for the reference system: CRS using molten salt as heat transfer fluid.

			Potential Technological Benefits	Potential Economical Benefits
Receiver innovations	1	Maximize working fluid temperature	Improve receiver performance and longevity	O&M reduction; assembly and installation cost reduction; some component cost reduction
	2	Increase homogeneity of solar insolation		
	3	Increase homogeneity of fluid flow		
	4	Hot spots management		
	5	Absorption instabilities management		
	6	Working fluid flow management		
Cycle Innovations	1	Increase working temperature	Increase system efficiency	System installed cost and LEC reduction
	2	Use superheated steam cycle		
	3	Add reheat stages		
	4	Avoid freezing of working fluid		

6.3.4. CRS using steam as heat transfer fluid

For this technology the homogeneity of the temperature and therefore the pressure in the receiver is essential to improve the efficiency. Hot spots can be reduced by an improved precision of concentrator tracking or/and an optimized fluid flow through the receiver cavity.

Table 6-7: Innovations for the reference system: CRS using steam as heat transfer fluid.

			Potential Technological Benefits	**Potential Economical Benefits**
Receiver innovations	1	Hot spots management	Improve receiver performance and longevity	O&M reduction; assembly and installation cost reduction; some component cost reduction
	2	Absorption instabilities management		
	3	Working fluid flow management		
Cycle Innovations	1	Maximize working fluid pressure	Increase system efficiency	System installed cost and LEC reduction
	2	Add steam superheating		
	3	Use PCM storage tank		
	4	Single large turbine for several towers		

6.3.5. CRS using atmospheric air as heat transfer fluid

Again hot spot management is essential for the receiver to avoid destruction of the wire-mesh volumetric absorber material.

Table 6-8: Innovations for the system: CRS using atmospheric air as heat transfer fluid.

			Potential Technological Benefits	**Potential Economical Benefits**
Receiver innovations	1	Matrix construction ("Lego" blocks)	Improve receiver performance and longevity	O&M reduction; assembly and installation cost reduction; some component cost reduction
	2	Air flow control		
	3	Hot spots management		
	4	Absorber instabilities management		
Cycle Innovations	1	Improve steam/air heat exchanger	Increase system efficiency	Significant component cost reduction; system installed cost and LEC reduction
	2	Design for superheated steam cycle		
	3	Add reheat stages		

6.3.6. CRS using pressurized air in combination with a solar hybrid gas turbine

In addition to the before described technologies a mayor point of improvement for this technology is to optimize the secondary optic design including the maximization of the window size of the receiver. The system is a multilevel receiver configuration (to increase the air temperature step by step up to about 1000°C). The solar high temperature heat is introduced into a gas-turbine which is supported by hybrid fuel. The combined cycle plant can be improved by gas-turbine modifications, with regard to increase the solar fraction.

Table 6-9: Innovations for the system: CRS using pressurized air in combination with a solar hybrid gas turbine

			Potential Technological Benefits	Potential Economical Benefits
Receiver innovations	1	Hot spots management	Improve receiver performance and longevity	O&M reduction; assembly and installation cost reduction; some component cost reduction
	2	Absorber instabilities management		
	3	Working fluid flow management		
	4	Secondary optics design		
	5	Maximize window size		
Cycle Innovations	1	Increase solar fraction	Increase system efficiency	System installed cost and LEC reduction
	2	GT combustor modification		
	3	GT adaptation for partial load operation		

6.3.7. Dish-engine system using Stirling or Brayton cycles

Table 6-10: Innovations for the system: Dish-engine system using Stirling or Brayton cycles.

			Potential Technological Benefits	Potential Economical Benefits
Receiver innovations	1	Tolerance to variable intensity distribution	Improve receiver performance and longevity	O&M reduction; assembly and installation cost reduction; some component cost reduction
	2	Minimize fluid volume		
Cycle Innovations	1	Increase engine size	Increase system efficiency	System installed cost and LEC reduction
	2	Improve longevity		
	3	Reduce maintenance		
	4	Free-piston Stirling increase size and adaptation for solar		
	5	Hybridization		
	6	Handle access solar power input		
	7	Increase dish size		
	8	Use Brayton Engine	Increase system reliability	System installed cost and LEC reduction
	8.1	Combustor adaptation		
	8.2	Partial load operation		
	8.3	Handle variable gravitation effects		

6.3.8. Summary

The aim to reduce the LEC by improvements of receivers and cycles for the parabolic trough technology can be summarized by two mayor fields:

- Increased maximum fluid (HTF or water/steam system) temperature,
- Reduced pressure losses (parasitics) in solar field and piping

For the calculations of LEC and the impact of innovations these two fields are relevant. They can be divided into various technical innovations, which are up to date on different development status.

Table 6-11: Summary of technical innovation for Receivers/Absorber and Cycles for trough systems.

Innovation class Trough system		Heat Collecting Elements (HCE) Receiver				Cycles			
		Advanced Coating	Eliminate Bellows	Improve Tube Joints and Design	Improve HTF	Add Reheat Stages	Increase Fluid Temperature / Superheat Steam	Decrease Pressure Losses	Use Organic Rankine Turbine
CSP plant type		Thermal oil & DSG	Thermal oil & DSG	Thermal oil & DSG	Thermal oil	Thermal oil & DSG	Thermal oil & DSG	Thermal oil & DSG	Thermal oil
Maturity in terms of	durability and robustness	Medium	N/A	N/A	Medium	High	Medium	N/A	High
	Performance/efficiency	Medium	N/A	N/A	Medium	High	Medium	N/A	High
Time required for full development and commercial implementation (High: More than 10 years, Medium: 5-10 years, Low: Less than 5 years)		Medium	Low	Low	Medium	Low	Medium	Low	Low
Cost figures dependence on	mass production	Medium	Low	Low	High	Low	Low	Low	Medium
	Spares/components replacement	High	Medium	Medium	Low	Low	Low	Medium	Medium
	Technological breakthroughs during development phase	High	Low	Medium	High	Low	High	High	Medium
	further scaling-up (power, size)	Low	Low	Low	Low	High	High	High	Medium
Potential of cost reduction (compared to today's figures) High: More than 60%, Medium: More than 30%, Low: Less than 30%		Medium	Low	Low	Medium	Low	Medium	Low	Low
Uncertainty	Technical / efficiency	Medium	Low	Low	High	Low	Low	Medium	Medium
	Economical	Low	Medium	Medium	High	Low	High	High	Medium
	Operational	Medium	Medium	Medium	High	Low	Medium	Low	Low
Risk	Technical / efficiency	Medium	Low	Low	Medium	Low	Low	Low	Medium
	Economical	Medium	Medium	Medium	Medium	Medium	High	Medium	High
	Operational	Medium	Medium	Medium	Low	Medium	Medium	Low	Medium

The aim to reduce the LEC by improvements of receivers and cycles for the Central receiver technology can be summarized by three mayor fields:

- Increased module size
- Increased receiver temperature
- Increased receiver performance

These mayor fields are relevant for the impact of innovations on LEC calculation as described in the following chapter.
Various technical innovations are imaginable which are up to date on different development status.

Table 6-12: Summary of innovation classes Receivers/Absorber and Cycles for Central Receiver Systems.

Innovation class Central Receiver Systems		Receivers						Cycles			
		Maximize Working Fluid Tempera-ture	Homo-geneity Of Solar Insolation / Hot Spot Manage-ment	Homo-geneity Of Fluid Flow / Fluid Manage-ment / Air Flow Control	Absorber Instability Manage-ment	Secondary Optics / Window Size	Matrix Construc-tion	Add Reheat Stages	Super-heated Steam/ Increase Temperature	Improve Heat Exchanger	Avoid Freezing
CSP plant type with HTF (molten salt MS; Steam; atmospheric air: AA; solar hybrid gas turbine: SOLGT)		MS / Steam	MS / steam / AA / SolGT	MS/ steam / AA / SolGT	MS / steam / AA / SOLGT	SOLGT	AA	MS / steam / AA	MS / AA	AA	MS
Maturity in terms of	durability and robustness	Medium	Medium	Medium	Medium	Medium	Medium	High	Medium	High	Low
	Performance/efficiency	low	Medium	Medium	Medium	Medium	Medium	High	Medium	High	Medium
Time required for full development and commercial implementation (High: More than 10 years, Medium: 5-10 years, Low: Less than 5 years)		Medium	Low	Low	Low	Medium	Low	Low	Medium	Low	Low
Cost figures dependence on	mass production	Low	Low	Low	Low	Medium	Medium	Low	Low	Medium	Low
	Spares/components replacement	Medium	Low	Low	Low	Medium	Medium	Low	Low	Medium	Medium
	Technological breakthroughs during development phase	High	Low	Low	Low	Low	Low	Low	High	Medium	Low
	further scaling-up (power, size)	High	Low	Low	Low	High	High	High	High	High	Low
Potential of cost reduction (compared to today's figures) High: More than 60%, Medium: More than 30%, Low: Less than 30%		Medium	Medium	Medium	Low	Medium	Medium	Low	Medium	Medium	High
Uncertainty	Technical / efficiency	Low	Low	Medium	Medium	Low	Low	Low	Low	Low	Medium
	Economical	High	Medium	Medium	Medium	Medium	Medium	Low	High	Medium	Low
	Operational	High	High	High	High	Medium	Low	Low	Medium	Low	High
Risk	Technical / efficiency	High	Medium	Medium	Medium	Medium	Low	Low	Low	Low	Medium
	Economical	High	Medium	Medium	Medium	Medium	Low	Medium	High	Medium	High
	Operational	High	High	High	High	Medium	Low	Medium	Medium	Low	High

7. Impact of innovations on reference systems

In this chapter the impact of each innovation is investigated by calculating the LEC using several annual simulations for the chosen site. The relevant reference system is used as baseline. The solar field size for the reference system is optimized in order to achieve minimal solar LEC for the relevant load curve and solar resource. Using this LEC value as starting point, the calculation is repeated for each innovation considered, changing only the main parameters for this innovation but keeping the remaining parameters unchanged compared to the reference system. This means, e.g. the solar field size is kept constant for all innovations of one reference system. This was done in order to ease the comparison and to limit the number of calculations. For some innovations, it would of course be useful to modify the design, especially the total reflective area, but the comparison between innovations would be impeded. Exceptions are those innovations, which need a considerable different solar field size, e.g. the storage innovations. The reflective area has to be enlarged for them, in order to generate excess heat for storage charging.

In addition to the individual calculation for each innovation, a combination of the selected innovations showing the largest impact on LEC is investigated, to demonstrate the summarized effects on LEC. The results shown here, do not consider any learning curve or mass production effects in the whole system or in other components. Those measures will have an additional and considerable impact on the LEC for solar thermal power plants.

To analyse the impact on the LEC using the ECOSTAR methodology, the innovations are “translated” to specific performance and cost input parameters. Two values for each of the parameters are chosen: one value representing the “high cost reduction estimation”, specifying an optimistic impact of the relevant innovation on this parameter and one value representing the “low cost reduction estimation”, based on a more conservative estimation. Using these two parameter sets for the annual calculation of each innovation gives boundary values for the LEC impact of each innovation.

Some parameter sets are common for several all even for all systems. As an example, the heliostat costs should be identical for all central receiver systems. Those common parameters are given here, whereas the specific parameters of the considered systems are presented in the subsequent subchapters.

Common parameter sets for all parabolic trough systems:

- Thin glass mirrors:
    - mean reflectivity is increased from 0.88 to 0.88 (low estimate) / 0.89 (high estimate)
    - specific investment cost for the solar field is reduced to 90/95% of the reference value
    - The O&M equipment cost percentage of investment is increased from 1.0% to 1.0/1.1% (to account for the potential increase in mirror breakages/damages)
- Multilayer plastics and innovative structures:
    - specific investment cost for the solar field is reduced to 70/90% of the reference value
- Dust repellent mirrors:
    - mean reflectivity is increased to 0.88/0.91 (to account for lower soiling)
    - The specific number of persons required for field maintenance is reduced from 0.03 to 0.02/0.025 persons per 1000 m² of aperture.

Common parameter sets for all central receiver systems:

- Ganged heliostats:

  - specific investment cost for the solar field is reduced to 80/90% of the reference value (120/135 €/m²)
- Large area heliostats:
  - specific investment cost for the solar field is reduced to 70/80% of the reference value (105/120 €/m²)
- Thin glass mirrors:
  - mean reflectivity is increased from 0.88 to 0.88/0.89
  - specific investment cost for the solar field is reduced to 90/95% of the reference value (135/143 €/m²)
  - The O&M equipment cost percentage of investment is increased from 1.0% to 1.0/1.1% (to account for the potential increase in mirror breakages/damages)
- Dust repellent mirrors:
  - mean reflectivity is increased to 0.88/0.91 (to account for lower soiling)
  - The specific number of persons required for field maintenance is reduced from 0.03 to 0.02/0.025 persons per 1000 m² of aperture.
- Autonomous heliostats:
  - specific investment cost for the solar field is reduced by 5/10 €/m² based on recent comparative analysis done for the PS10 project.

7.1. Parabolic trough technology using thermal oil as heat transfer fluid

In addition to the common parameter sets given at the beginning of chapter 6, the specific parameters for this system are:

- 1-tank thermocline molten salt storage:
    - Specific costs of 20/25 €/kWh for the storage are assumed instead of 31 €/kWh for the 2-tank storage
- Concrete storage:
    - Specific costs of 18/22 €/kWh for the storage are assumed
    - HTF temperature at discharging is reduced to 360°C
- Tubeless concrete storage:
    - Specific costs of 15/19 €/kWh for the storage are assumed
    - HTF temperature at discharging is reduced to 360°C
- Tubeless concrete storage with advanced charging/discharging concepts:
    - Specific costs of 9/15 €/kWh for the storage are assumed
    - HTF temperature at discharging is the same as for the 2-tank molten salt system (371°C)
- Increased maximum HTF temperature
    - HTF temperature is increased to 450/480°C
    - Design efficiency of the power block is increased to 39/41%
    - Mean HTF temperature at storage discharging is increased to 430/460°C
- Reduced parasitics:
    - Factor for solar field parasitics is reduced from 0.0098 kW/m² to 0.004/0.006 kW/m² aperture
- Combination of selected measures:
    - Multilayer plastics and innovative structures
    - Dust repellent mirrors
    - Tubeless concrete storage with advanced charging/discharging
    - Increased maximum HTF temperature
    - Reduced parasitics

Figure 7-1 shows the relative LEC reduction for solar thermal parabolic trough power plants using thermal oil as HTF and a thermal storage which would enable a three hours full load operation of the plant if it is completely filled. The input for these calculation results is shown in Table 7-1. Changes compared to the reference system are highlighted in blue. The impact of the individual measures on LEC is limited, but when the most promising measures are combined, there is a considerable decrease in LEC as shown by the rightmost column of Figure 7-1. Most effective measures in the sense of LEC reduction are innovations impacting concentrator and storage costs. Multilayer plastics and new mirror concepts present one option with a high potential of concentrator cost-reduction, thus appearing worthwhile to be explored more deeply. Advanced storage concepts also offer a significant cost reduction potential and should be in the focus of future R&D activities.. This result has to be evaluated taking into account the risks and development efforts documented in chapter 4. The main risk associated with front surface mirrors made of other materials than glass is their long term durability. For thin glass mirrors a technology to bend the thin glass mirrors into the parabolic shape is missing. Multilayer plastics in combination with innovative structures need to proof their durability. But both innovations mentioned above are considered to be available in a relative short time period, whereas dust repellent mirrors will need more research time for commercial availability.
The 1-tank thermocline storage should be commercially available within a short term because it uses almost the same technology as the 2-tank molten salt storage of the reference system. The only uncertainty of this system is the performance in a large scale application due to a

deranged thermocline. The tube type concrete storage may be considered as close to pilot phase scale technology needing a large scale demonstration to proof cost figures and long term stability. The tubeless concrete storage needs some more developing efforts but the cost reduction potential seems to be promising, particularly if it is used in combination with advanced charging/discharging concepts.
Increased HTF temperatures (using with thermal oil heat transfer fluid) need progress in the development of such fluids by the chemical industry to develop a HTF which is stable up to this temperature. Up to now only small margins exist in the temperature stability of the selective absorber coatings so that improvements are needed here, too. Minimizing the parasitics is an ongoing task and though it needs some efforts, the expected benefits as well as the associated risk is considered relatively low.

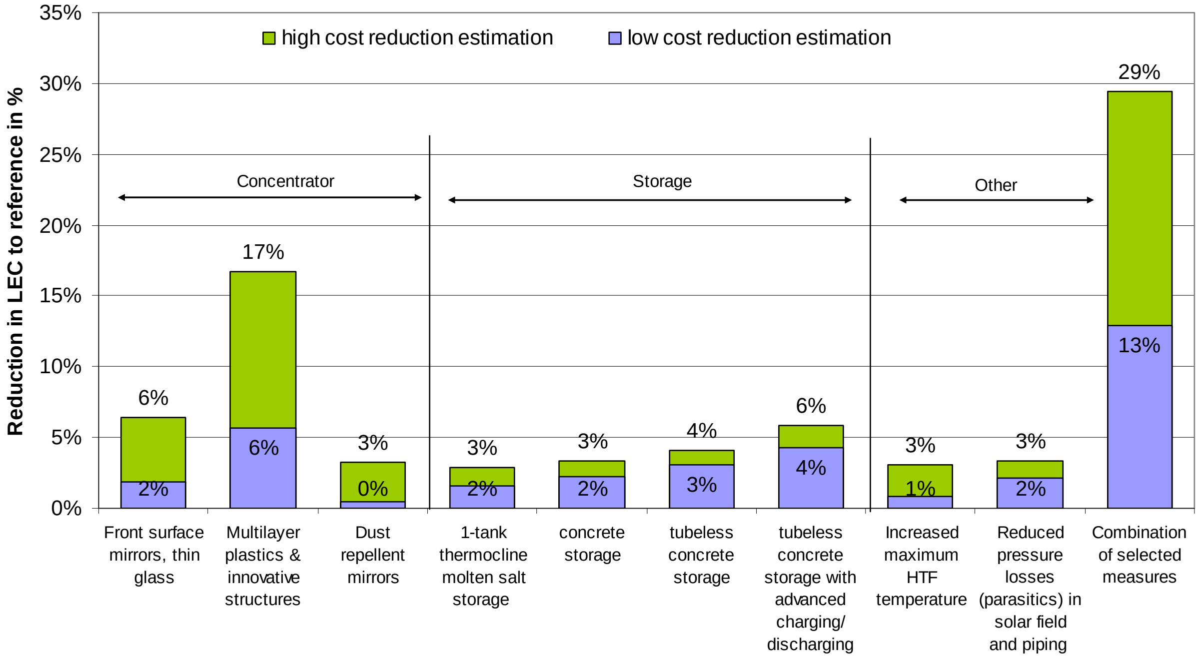


Figure 7-1: Impact of innovations on LEC for solar-only operation of a parabolic trough plant with HTF and 3h thermal storage (full load from 9a.m. – 11p.m.).

The relative results depend only weekly on the chosen operating mode. Full load operation for 24h per day) gives solar LEC which are slightly lower than for the 9 a.m. -11 p.m. since the annual capacity factor increases. The relative impact of the individual measures is more or less independent of the operation mode. The impact of the storage related innovations is higher, because the storage capacity and therefore the cost fraction of this part of the plant is larger than for the 9 a.m. – 11. p.m. operation mode.

Table 7-1: Main input data for the parabolic trough/HTF reference system and the considered innovations.

Innovation		Reference parabolic trough with 2-tank molten salt storage	Front surface mirrors, thin glass	Multilayer plastics & innovative structures	Dust repellent mirrors	1-tank thermocline molten salt storage	concrete storage	tubeless concrete storage	tubeless concrete storage with advanced charging/ discharging	Increased maximum HTF temperature	Reduced pressure losses (parasitics) in solar field and piping	Combination of selected measures
Technical Input												
aperture area of the solar field	m²	442035	442035	442035	442035	442035	442035	442035	442035	442035	442035	442035
average reflectivity	-	0.88	0.88 / 0.89	0.88	0.88 / 0.91	0.88	0.88	0.88	0.88	0.88	0.88	0.88 / 0.91
HTF temperature at field exit	°C	391	391	391	391	391	391	391	391	450 / 480	391	450 / 480
Factor for Solar field Parasitcs		0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.006 / 0.004	0.006 / 0.004
design parasitics for pumping and tracking	kW	4332	4332	4332	4332	4332	4332	4332	4332	4332	2653 / 1768	2653 / 1768
design net electrical output	kW	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
design efficiency of the power block	-	0.375	0.375	0.375	0.375	0.375	0.375	0.375	0.375	0.39 / 0.41	0.375	0.39 / 0.41
storage capacity	h	3	3	3	3	3	3	3	3	3	3	3
thermal capacity of the storage	kWh	434656	434656	434656	434656	434656	434656	434656	434656	417938	421221	405017
HTF temperature in storage discharging	°C	371	371	371	371	371	360	360	371	430 / 460	371	430 / 460
O&M Input												
number of persons power plant		30	30	30	30	30	30	30	30	30	30	30
Specific number of persons for field maintenance	1/1000m²	0.030	0.030	0.030	0.025 / 0.02	0.030	0.030	0.030	0.030	0.030	0.030	0.025 / 0.02
O&M Equipment costs percentage of investment	% per a	1.0	1.1 / 1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1 / 1.0
Cost input												
specific investment for solar field	€/m²	206	196 / 185	185 / 144	206	206	206	206	206	206	206	185 / 144
spec. investment for power block	€/kW$_e$	700	700	700	700	700	700	700	700	700	700	700
spec. investment for storage	€/kWh$_{th}$	31	31	31	31	25 / 20	22 / 18	19 / 15	15 / 9	31	31	15 / 9

7.2. Parabolic trough technology using water/steam as heat transfer fluid

In addition to the common parameter sets given at the beginning of chapter 6, the specific parameters for this system are:

- Up-scaling of power block to 47 MW
    - Design efficiency of the power block is increased from 26% to 38.5%
    - Specific investment cost of the power block is increased to 700 €/kW to account for the more sophisticated Rankine cycle
    - Total reflective area is reduced significantly since the more efficient power block needs a lower thermal input for the same electricity production
- Advanced storage (combination of PCM and concrete storage):
    - A 3h storage is added
    - Solar field size is increased again, to deliver excess thermal energy for storage charging
    - Specific costs of 20/30 €/kWh for the storage are assumed
- Increased solar field outlet temperature
    - Steam temperature at field outlet is increased from 411°C to 450/480°C
    - Design efficiency of the power block is increased to 41.5/39.5%
- Reduced parasitics:
    - Factor for solar field parasitics is reduced from 0.009 kW/m² to 0.004/0.006 kW/m² aperture due to lower pumping power requirements compared to the thermal oil circuit.
- Combination of selected measures:
    - Front surface mirrors
    - Dust repellent mirrors
    - advanced concrete storage
    - Increased field outlet temperature
    - Reduced parasitics

Figure 7-2 shows the relative LEC reduction for solar thermal parabolic trough power plants using direct steam generation in the solar field. The actual impact of the innovations on performance and cost input compared to the reference system is shown in Table 7-2, where changes compared to the reference system are highlighted in blue colour. Due to the reasons already explained in Section 4.2, the most significant improvement is due to the increase of the unit size of the power block from 4.7 MW_{el} to 47 MW_{el}. Compared to parabolic trough systems using thermal oil and storage, the DSG system should achieve a lower LEC even without storage and operating at the same average outlet temperature. An increase in the fluid temperature and the addition of thermal energy storage would result in further cost reduction. Modifications in the concentrator like those discussed in the previous sections are applicable too. In Figure 7-3 the steps of a successive DSG implementation strategy are presented. First DSG systems without storage at the same power level as current parabolic trough plants using thermal oil lead to moderate cost reductions in the order of 6%. A subsequent increase in the fluid temperature adds up to 8% reduction in LEC. Including a high cost storage option may result in a cumulative reduction of up to 11.7 %, low cost storage systems even yield more than 14%. Other measures to improve the collector cost and performance generally applicable to parabolic trough collectors finally show a cost reduction potential of up to 35% compared to today's parabolic trough technology. The operation mode considered for the evaluation of the impact of innovations depicted in Figure 7-2 is full load operation from 9 a.m. to 11 p.m.

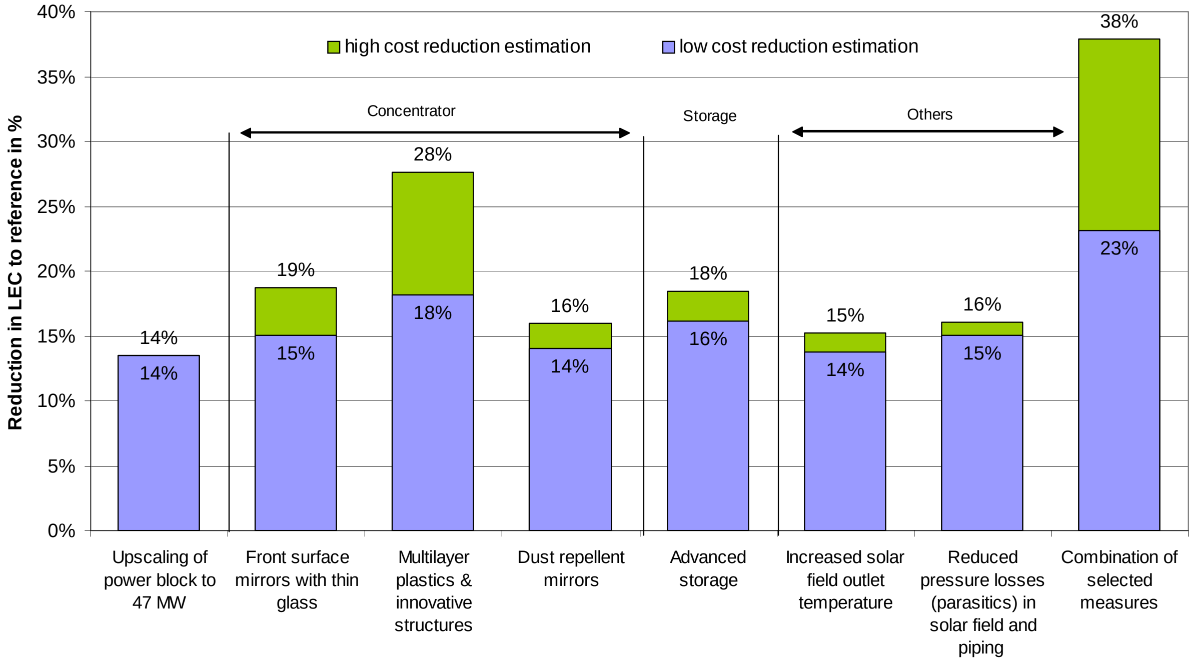


Figure 7-2: Impact of innovations on LEC for solar-only operation of a DSG parabolic trough plant with thermal storage (full load from 9 a. m. to 11 p.m.).

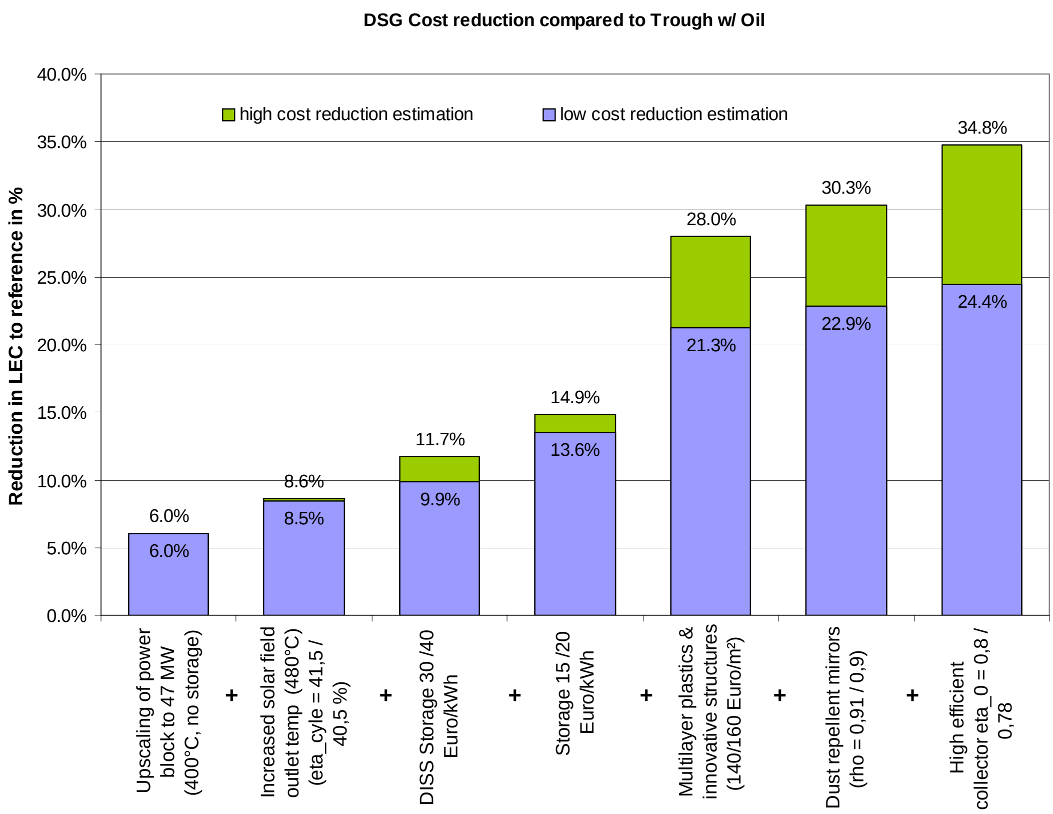


Figure 7-3: Cumulative cost reduction of parabolic trough DSG Systems compared to parabolic trough with oil reference system.

Figure 7-4 shows the impact of different measures on the solar LEC for the linear Fresnel system. As already explained in chapter 4.2, the linear Fresnel is considered as innovation for a parabolic trough system with direct steam generation. Due to the different models used for both systems, the results for the linear Fresnel system are presented in a separate figure. The baseline for the relative LEC is given by a DSG parabolic trough system of the same size. Table 7-3 lists the main input data for the innovations considered.
The cost input for the Fresnel collector is ranging between 110 und 140 €/m². While the optimistic figure would result in a reduction of approx. 4%, the conservative figure would yield a cost increase by 8%. These negative cost reduction values are caused by the reference value. The impact of the other innovations also considered for the DSG parabolic trough option is also presented in the same figure. It is limited because in the cost calculation for the reference linear Fresnel concept, some of the innovations proposed for the parabolic trough system are already anticipated: thin glass mirrors and innovative structures. This is the reason for the solar field costs mentioned above. Based on these figures it appears not clear today whether Linear Fresnel systems will be able to contribute substantially to the cost reduction of concentrating solar power systems.

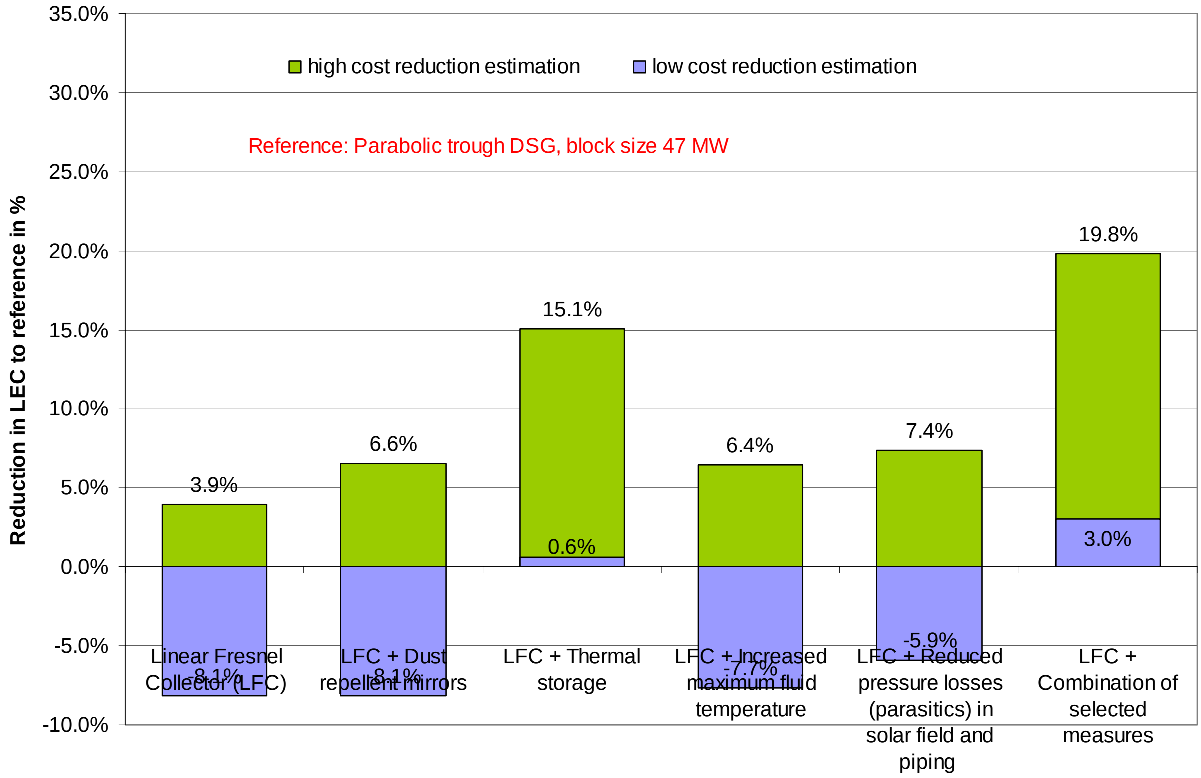


Figure 7-4: Impact of innovations on LEC for solar-only operation of a Linear Fresnel power plant using DSG compared to the reference parabolic trough DSG system of 47 MW (full load from 9 a.m. to 11 p.m.).

Table 7-2: Main input data for the DSG parabolic trough reference system and the considered innovations.

Innovation		Reference DSG parabolic trough 10 units 4.7MW each	Upscaling of power block unit from 4.7 MW_{el} to 47 MW_{el}	Front surface mirrors with thin glass	Multilayer plastics & innovative structures	Dust repellent mirrors	Advanced PCM and concrete storage	Increased Solar field outlet temperature	Reduced pressure losses (parasitics) in solar field and piping	Combination of all the innovations considered in this study
Technical Input										
aperture area of the solar field	m²	448191	337040	337041	337040	337040	394408	337040	337040	394408
average reflectivity	-	0.88	0.88	0.89	0.88	0.89 / 0.91	0.88	0.88	0.88	0.89 / 0.91
HTF temperature at field exit	°C	411	411	411	411	411	411	450 / 480	411	450 / 480
Factor for Solar field Parasitcs		0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.006 / 0.004	0.006 / 0.004
design parasitics for pumping and tracking	kW	4034	3033	3033	3033	3033	3550	3033	2022 / 1348	2366 / 1578
design net electrical output	kW	10 * 4.7	47000	47000	47000	47000	47000	47000	47000	47000
design efficiency of the power block	-	0.25	0.385	0.385	0.385	0.385	0.385	0.395 / 0.415	0.385	0.395 / 0.415
storage capacity	h	0	0	0	0	0	3	0	0	3
thermal capacity of the storage	kWh	0	0	0	0	0	393894	0	0	351164 / 374935
HTF temperature in storage discharging	°C	380	380	380	380	380	380	420 / 450	380	420 / 450
O&M Input										
number of persons power plant		30	30	30	30	30	30	30	30	30
Specific number of persons field maintenance	1/1000m²	0.030	0.030	0.030	0.030	0.025 / 0.02	0.030	0.030	0.030	0.025 / 0.02
O&M Equipment costs percentage of investment	% per a	1.0	1.1 / 1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1 / 1.0
Cost input										
specific investment for solar field	€/m²	190	190	181 / 171	171 / 133	190	190	190	190	171 / 133
spec. investment for power block	€/kW_e	435	700	700	700	700	700	700	700	700
spec. investment for storage	€/kWh_{th}	30	30	30	30	30	30 / 20	30	30	30 / 20

Table 7-3: Main input data for the linear Fresnel system and the considered innovations.

Innovation		Reference DSG parabolic trough 47 MW_{el}	Linear Fresnel Collector (LFC)	LFC + Dust repellent mirrors	LFC + Thermal storage	LFC + Increased maximum fluid temperature	LFC + Reduced pressure losses (parasitics) in solar field and piping	LFC + Combination of selected measures
Technical Input								
aperture area of the solar field	m²	337040	376200	376200	532954	376200	376200	532954
average reflectivity	-	0.88	0.89	0.89 / 0.91	0.88	0.88	0.88	0.89 / 0.91
HTF temperature at field exit	°C	411	411	411	411	450 / 480	411	450 / 480
Factor for Solar field Parasitics		0.009	0.009	0.009	0.009	0.009	0.006 / 0.004	0.006 / 0.004
design parasitics for pumping and tracking	kW	3033	3386	3386	4797	3386	2257 / 1505	3198 / 2132
design net electrical output	kW	47000	50000	50000	50000	50000	50000	50000
design efficiency of the power block	-	0.385	0.385	0.385	0.385	0.395 / 0.415	0.385	0.395 / 0.415
storage capacity	h	0	0	0	3	0	0	3
thermal capacity of the storage	kWh	0	0	0	426986	0	0	395938 / 376857
HTF temperature in storage discharging	°C	380	380	380	380	420 / 450	380	420 / 450
O&M Input								
number of persons power plant		30	30	30	30	30	30	30
Specific number of persons field maintenance	1/1000m²	0.030	0.030	0.025 / 0.02	0.030	0.030	0.030	0.025 / 0.02
O&M Equipment costs percentage of investment	% per a	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Cost input								
specific investment for solar field	€/m²	190	140 / 110	140 / 110	140 / 110	140 / 110	140 / 110	140 / 110
spec. investment for power block	€/kW_e	700	700	700	700	700	700	700
spec. investment for storage	€/kWh_{th}	31	31	31	30 / 20	31	31	30 / 20

7.3. CRS using molten salt as heat transfer fluid

In addition to the common parameter sets given at the beginning of chapter 6, the specific parameters for this system are:

- 1-tank thermocline molten salt storage:
    - Specific costs of 9/11 €/kWh for the storage are assumed instead of 14 €/kWh for the 2-tank storage
- Scale-up of the module size to 51 MW
    - Total reflective area is reduced since the more efficient power block needs a lower thermal input for the same electricity production
    - Design efficiency of the power block is increased to 39/40%
    - Total costs for the tower (only 1 larger tower instead of 3 smaller ones) are reduced to 2.8/4.4 M€
- Combination of selected measures:
    - Scale-up of the module size
    - Large area heliostat
    - Thermocline storage
    - Dust repellent mirrors

As it may be seen in the bar chart a LEC reduction of up to 25% may be achieved by combining selected measures. We could consider this combination of low risk or short term.
Results on the LEC of such an innovations are shown in the bar plot of Figure 7-5.

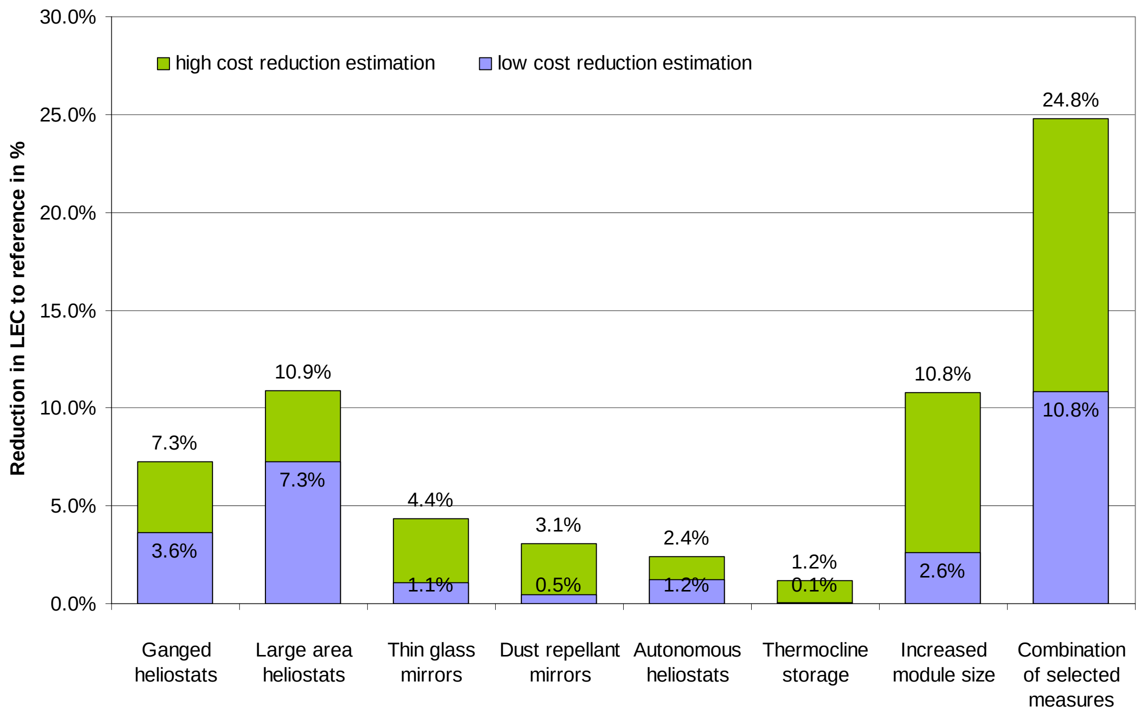


Figure 7-5: Impact of innovations on LEC for the molten salt SCR system (full load from 9 a.m. to 11 p.m.).

Table 7-4 compiles the details on inputs and outputs from the analysis of these innovations. Blue cells are highlighted to distinguish the changes respect to the reference case in each innovation column.

From the previous sensitivity analysis on innovations it can be concluded that molten salt SCR technology is strongly influenced by the size of the heat storage. After the large area heliostats, the second most important factor is increasing the number of operating hours to 24-h. Large storage systems of about 15 h nominal are the most economical solution. A simple combination of low-cost heliostats with 15-h storage, and perhaps the use of wireless heliostat fields, would be enough to reduce the LEC by more than 25% in the short term by innovation aspects.

Table 7-4: Main input data for the CRS molten salt reference system and the considered innovations.

Innovation		**Reference system**	**Ganged heliostats**	**Large area heliostats**	**Thin glass mirrors**	**Dust repellant mirrors**	**Auto-nomous heliostats**	**Thermocline storage**	**Increased module size**	**Combination of selected measures**
Technical Input										
aperture area of the solar field	m²	458160	458160	458160	458160	458160	458160	458160	429525	429525
average reflectivity	-	0.88	0.88	0.89	0.88 / 0.89	0.88 / 0.91	0.88	0.88	0.87 / 0.88	0.87 / 0.91
max. air temperature at receiver exit	°C	565	565	565	565	565	565	565	565	565
Factor for Solar field Parasitcs		0.01625	0.01625	0.01625	0.01625	0.01625	0.01625	0.01625	0.01625	0.01625
design parasitics	kW	7445	7445	7445	7445	7445	7445	7445	7445	7445
design net electrical output	kW	3*17000	3*17000	3*17000	3*17000	3*17000	3*17000	3*17000	51000	51000
design efficiency of the power block	-	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.39 / 0.40	0.39 / 0.40
storage capacity	h	3	3	3	3	3	3	3	3	3
thermal capacity of the storage	kWh	461409	461409	461409	461409	461409	461409	461409	449578 / 438338	449578 / 438338
fluid temperature at storage discharging	°C	560	560	560	560	560	560	560	560	560
O&M Input										
number of persons power plant		30	30	30	30	30	30	30	30	30
Specific number of persons field maintenance	1/1000m²	0.030	0.030	0.030	0.030	0.0025 / 0.02	0.030	0.030	0.030	0.0025 / 0.02
Cost input										
specific investment for solar field	€/m²	150	135 / 120	120 / 105	143 / 135	150	145 / 140	150	150	120 / 105
spec. investment for power block	€/kW_e	750	750	750	750	750	750	750	700 / 550	700 / 550
spec. investment for storage	€/kWh_{th}	14	14	14	14	14	14	11 / 9	14	11 / 9
total investment cost for towers	M€	5.6	5.6	5.6	5.6	5.6	5.6	5.6	4.4 / 2.8	4.4 / 2.8

7.4. CRS using saturated steam as heat transfer fluid

In addition to the common parameter sets given at the beginning of chapter 6, the specific parameters for this system are:

- Advanced storage:
    - Storage capacity is increased to 3 hours
    - Solar field size is increased to enable storage charging
    - Specific costs of 25/35 €/kWh for the storage are assumed instead of 100 €/kWh for the storage of the reference system
- Change from saturated to superheated steam
    - The specific cost of the receiver is increased from 110 to 140/160 €/kWh (due to the necessity of a dual receiver, one for saturated and other for superheated steam)
    - The design power block efficiency is increased to 38/40%
    - Working temperature is increased up to 550 ºC.
- Scale-up of the module size to 55 MW
    - Total reflective area is reduced since the more efficient power block needs a lower thermal input for the same electricity production
    - Design efficiency of the power block is increased to 33/35%
    - Total costs for the tower (only 1 larger tower instead of 5 smaller ones) are reduced to 4.5/7.1 M€
- Combination of selected measures:
    - Dust repellent mirrors
    - Large area heliostats
    - Advanced storage
    - Scale-up of the module size
    - Change to superheated steam

Results on the LEC of such a innovations are shown in the bar plot of next Figure. LEC reduction is estimated about a 20 - 33% with this combination and the above mentioned assumptions in the parametric definition of the innovations.

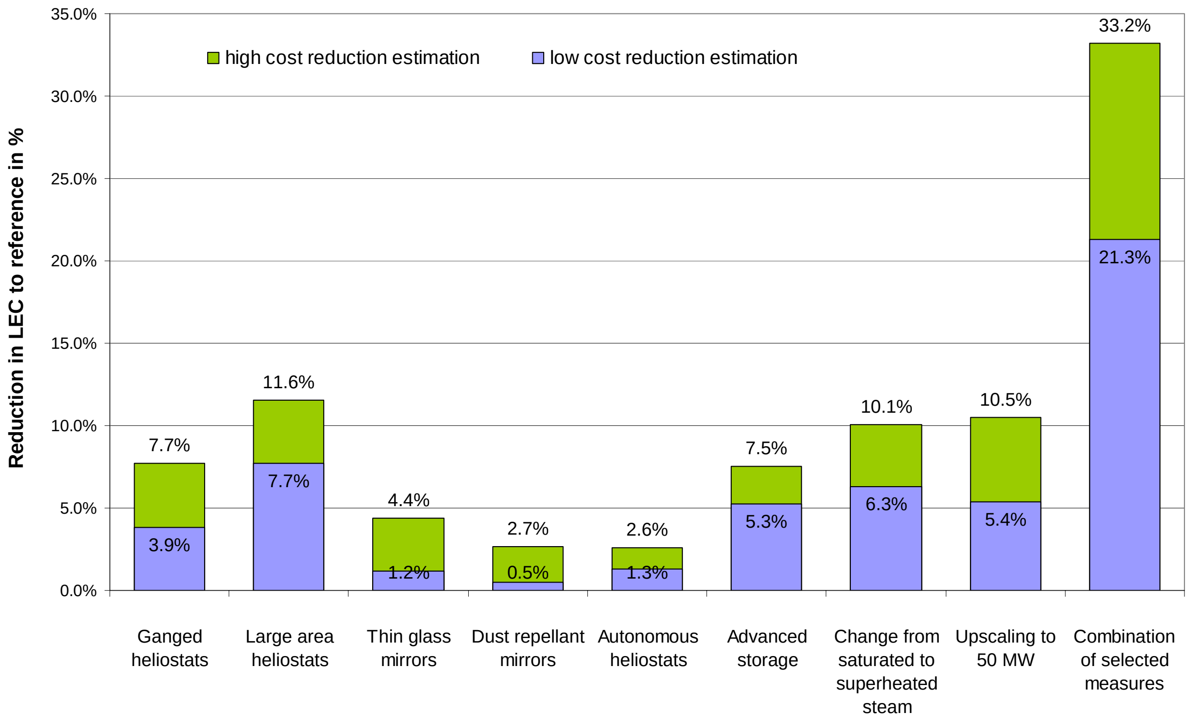


Figure 7-6: Impact of innovations on LEC for the SCR saturated steam system (full load from 9 a.m. to 11 p.m.).

From the previous sensitivity analysis on innovations it can be concluded that saturated steam SCR plants may achieve a 33% reduction of LEC. The challenges are significant because the problem of superheated steam receivers is not solved today although it has been addressed in previous CRS demonstration plants. Scaling the receiver concept does not appear very easy. The low-cost storage of steam also needed for DSG technology is also not solved today. Unlike other CRS technology approaches studied here, which show the benefit of low cost storage option like molten salt, high temperature cycles like air receivers, the steam concept doesn't present any intrinsic benefits compared to the parabolic trough / Fresnel approach that may justify the higher effort of a two-dimensional concentration. Table 7.5 compiles the details on inputs and outputs from the analysis of these innovations. Blue cells are highlighted to distinguish the changes respect to the reference case in each innovation column.

Table 7-5: Main input data for the CRS saturated steam reference system and the considered innovations.

Innovation		**Reference system**	**Ganged heliostats**	**Large area heliostats**	**Thin glass mirrors**	**Dust repellant mirrors**	**Auto-nomous heliostats**	**Advanced storage**	**Change from saturated to superheated steam**	**Upscaling to 55 MW**	**Combination of selected measures**
Technical Input											
aperture area of the solar field	m^2	465032	465032	465032	465032	465032	465032	606564	424595	465032	505470
average reflectivity	-	0.88	0.88	0.89	0.88 / 0.89	0.88 / 0.91	0.88	0.88	0.88	0.88	0.88 / 0.91
ive steam temperature	°C	260	260	260	260	260	260	260	550	260	550
Factor for Solar field Parasitcs		0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016
design parasitics	kW	744	744	744	744	744	744	971	679	744	809
design net electrical output	kW	5*11000	5*11000	5*11000	5*11000	5*11000	5*11000	5*11000	5*11000	55000	55000
design efficiency of the power block	-	0.303	0.303	0.303	0.303	0.303	0.303	0.303	0.38 / 0.40	0.33 / 0.35	0.38 / 0.40
storage capacity	h	0.40	0.4	0.4	0.4	0.4	0.4	3	0.4	0.4	3
thermal capacity of the storage	kWh	73590	73590	73590	73590	73590	73590	554163	55679	63707	418566
fluid temperature at storage discharging	°C	260	260	260	260	260	260	250	530	260	530
O&M Input											
number of persons power plant		30	30	30	30	30	30	30	30	30	30
Specific number of persons field maintenance	$1/1000m^2$	0.030	0.030	0.030	0.030	0.025 / 0.02	0.030	0.030	0.030	0.030	0.025 / 0.02
Cost input											
specific investment for solar field	$€/m^2$	150	135 / 120	120 / 105	143 / 135	150	145 / 140	150	150	150	120 / 105
Spec. investment for receiver	$€/kW_{th}$	110	110	110	110	110	110	110	160 / 140	110	160 / 140
spec. investment for power block	$€/kW_e$	636	636	636	636	636	636	636	636	600 / 550	600 / 550
spec. investment for storage	$€/kWh_{th}$	100	100	100	100	100	100	35 / 25	100	100	35 / 25
total investment cost for towers	M€	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	7.1 / 4.5	7.1 / 4.5

7.5. CRS using atmospheric air as heat transfer fluid

In addition to the common parameter sets given at the beginning of chapter 6, the specific parameters for this system are:

- PCM cascade storage:
  - Specific costs of 25/35 €/kWh for the storage are assumed
- Mobile solid material storage:
  - Specific cost of the storage are reduced to 20/35 €/kWh$_{th}$
  - To account for the parasitics increase, the "Factor for power block parasitics" is increased from 0.03 to 0.04/0.06 (because there is no separate parameter to account for parasitics in the storage). This parameter stands for parasitics/net electric output.
- Storage: solid material with ceramic saddles:
  - Specific cost of the storage is reduced to 20/40 €/kWh$_{th}$
- Scale-up of the module size to 50 MW
  - Total reflective area is reduced since the more efficient power block needs a lower thermal input for the same electricity production
  - Design efficiency of the power block is increased to 36/38%
  - Total costs for the tower (only 1 larger tower instead of 5 smaller ones) are reduced to 4.5/7.1 M€
- Increased receiver performance:
  - The receiver performance is increased by 10/15%.
- Combination of selected measures:
  - Dust repellent mirrors
  - Large area heliostats
  - Storage with mobile solid material
  - Scale-up of the module size
  - Improved receiver performance

Results on the LEC of such innovations are shown in the bar plot of Figure 7-7. The SCR with atmospheric air receiver technology may benefit from its simple design that promises quick start-ups and high reliability figures in the first pilot units. However essential further improvements are necessary to achieve similar cost figures than the other technologies presented here. Improvements should mainly focus in the receiver performance, in the integration into a larger power blocks to take benefit from increased cycle performance and in a reduction of the storage costs. Like in all other cases, innovations in the concentrator have the potential to provide essential reductions, too.
The analysis show that innovation may lead to similar cost figurers that for the other technologies presented.

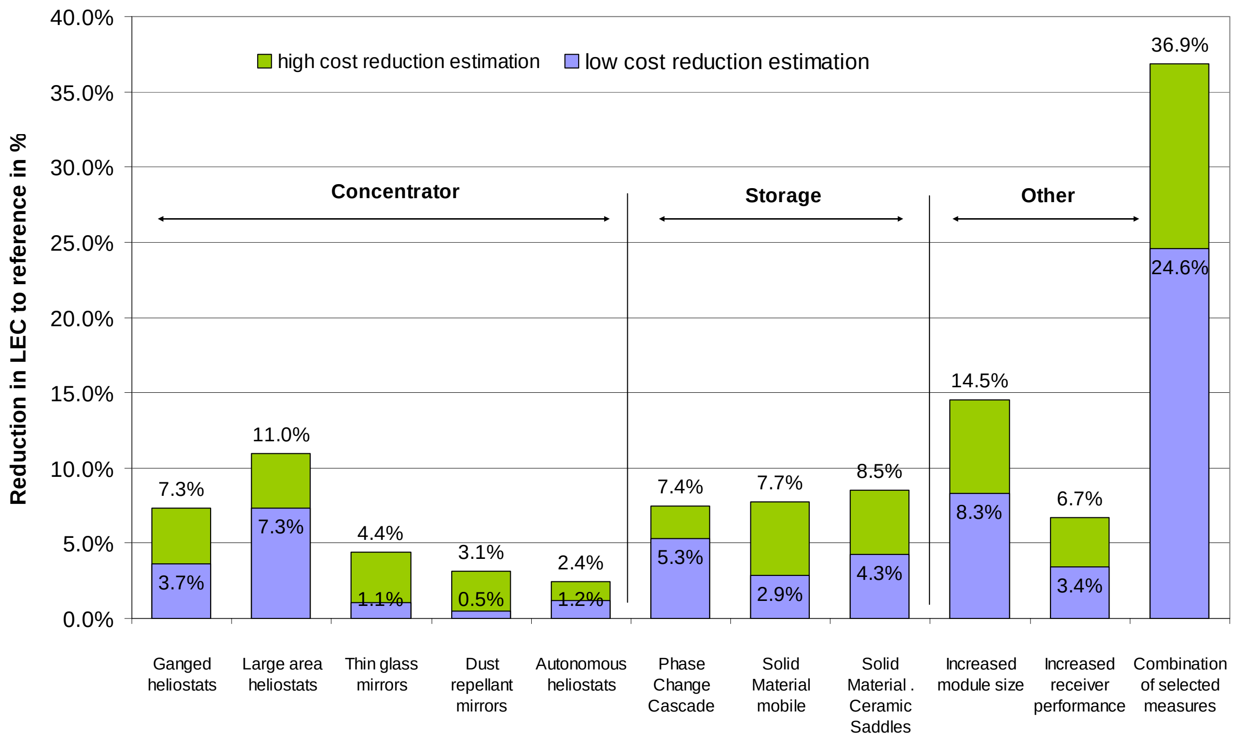


Figure 7-7: Impact of innovations on LEC for the CRS/atmospheric air system (full load from 9 a.m. to 11 p.m.).

Table 7-6 compiles the details on inputs and outputs from the analysis of these innovations. Blue cells are highlighted to distinguish the changes respect to the reference case in each innovation column.

Table 7-6: Main input data for the central receiver system using atmospheric air reference system and considered innovations.

Innovation		**Reference system**	**Ganged heliostats**	**Large area heliostats**	**Thin glass mirrors**	**Dust repellant mirrors**	**Auto-nomous heliostats**	**Phase Change Cascade**	**Solid Material mobile**	**Solid Material . Ceramic Saddles**	**Increased module size**	**Increased receiver per-formance**	**Com-bination of selected measures**
Technical Input													
aperture area of the solar field	m^2	522900	522900	522900	522900	522900	522900	522900	522900	522900	435750	435750	435750
average reflectivity	-	0.88	0.88	0.88	0.88 / 0.89	0.88 / 0.91	0.88	0.88	0.88	0.88	0.87 / 0.88	0.88	0.87 / 0.88
max. air temperature at receiver exit	°C	680	680	680	680	680	680	680	680	680	680	680	680
Factor for receiver efficiency		1	1	1	1	1	1	1	1	1	1	1.1 / 1.15	1.1 / 1.15
design parasitics	kW	3399	3399	3399	3399	3399	3399	3399	3399	3399	2832	2832	2832
design net electrical output	kW	5*10000	5*10000	5*11000	5*10000	5*10000	5*10000	5*10000	5*10000	5*10000	50000	5*10000	50000
design efficiency of the power block	-	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.39 / 0.41	0.34	0.39 / 0.41
Factor for power block parasitics	-	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04 / 0.06	0.03	0.03	0.03	0.03
thermal capacity of the storage	kWh	471166	471166	471166	471166	471166	471166	471166	471166	471166	406403 / 386578	466168	406403 / 386578
fluid temperature at storage discharging	°C	650	650	650	650	650	650	650	650	650	650	650	650
O&M Input													
number of persons power plant		30	30	30	30	30	30	30	30	30	30	30	30
Specific number of persons field maintenance	1/1000m^2	0.030	0.030	0.030	0.030	0.025 / 0.02	0.030	0.030	0.030	0.030	0.030	0.030	0.025 / 0.02
Cost input													
specific investment for solar field	€/m^2	150	125 / 120	120 / 105	143 / 135	150	145 / 140	150	150	150	150	150	120 / 105
spec. investment for power block	€/kW_e	600	600	600	600	600	600	600	600	600	600 / 580	600	600 / 580
spec. investment for storage	€/kWh_{th}	60	60	60	60	60	60	35 / 25	35 / 20	40 / 20	60	60	35 / 20
total investment cost for towers	M€	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	7.1 / 4.5	8.9	7.1 / 4.5

7.6. CRS using pressurized air in combination with a solar hybrid gas-turbine

In contrast to the other concentrating solar power generation technologies discussed in this study, this is a hybrid system and it needs a certain amount of fossil fuel even at design solar input. This is due to the current temperature limit of the available pressurized receivers, which recently have been tested up to 1000°C. Modern high efficient gas turbines exhibit nominal turbine entrance temperatures of 1100 to 1200°C or even higher, which may not be achieved using the existing receivers. On the other hand, the receiver development is going on and an advanced receiver type may be capable for solar only operation in the future.
In addition to the common parameter sets given at the beginning of chapter 6, the specific parameters for the innovations considered for this system are:

- Thermal storage:
    - A 3h storage is included.
    - Solar field size is increased in order to facilitate storage charging
    - Specific costs of 20/30 €/kWh for the storage are assumed
- Increased module size:
    - Instead of 4 modules of 14.6 MW net output one module with 64.4 MW is calculated

    This is done by changing the following parameters:
    - Field mean reflectivity is "penalised" changing the mean annual reflectivity to 0.87 / 0.88, because a larger field may have a lower optical efficiency due to increased distance between many of the heliostats and the receiver.
    - Design efficiency of the Power Block is increased to 46/49%
    - Specific investment in the power block is reduced from 700 to 550/600 €/kW
    - Total investment in towers is reduced to 3.6/5.8 M€
- Increased receiver temperature:
    - Air temperature at receiver exit is increased from 800°C to 1000°C
    - Solar field size is increased, to provide the increased solar thermal input for the gas turbine
    - Specific investment of the receiver is increased from 150€/kW to 180/165 €/kW
- Increased receiver performance:
    - Mean reflectivity is increased from 0.88 to 0.89/0.91
    - Solar field size is reduced
- Combination of selected measures:
    - Large area heliostats
    - Dust repellent mirrors
    - Increased module size
    - thermal storage integration

For hybrid systems like the CRS with pressurized air and gas turbine, of the LEC depend on the fossil share of the plant. The LEC is calculated using the total annual costs and the total annual electricity production as shown in chapter 1.3. To the present distinctions between the costs of solar electricity generation and fossil generation it is beneficial to split the generation cost to the solar and fossil part. For some of the costs (e.g.: the solar field or the fuel costs) the division is rather obvious, since they are clearly assigned to one of these categories. This is different for power block costs and for the electricity generation, they are separated according to the shares of thermal input of solar heat and fossil heat based on LHV.
Figure 7-8 shows the solar LEC for the innovations proposed for the CRS with pressurized air and gas turbine. The annual solar fraction for full load operation from 9 a.m. to 11 p.m. is 19% for almost all cases, except for the thermal storage case, the storage case, the increased receiver temperature case and the combination of measures case, where it is 30%. In general, a comparison of the hybrid LEC for different solar fractions is misleading, since it represents a

blended number and the relative share of fossil and solar costs are changing with the solar fraction. Thus we focus on the solar LEC in this case to identify most relevant innovations although the blended hybrid LEC are presented in Figure 7-9, too.
A larger module size, in this case one 50 MWe power block instead of four single units, shows the largest impact on the LEC. Lower investment in conjunction with higher performance leads to benefits for both the solar and the fossil operation. The integration of a solar receiver into a larger gas turbine system is a big challenge and associated with high uncertainties and risks. However, in this concept it is essential step to reduce the cost significantly.
Ganged heliostats with an estimated cost reduction potential of 20% for these parts, provide a decrease of 7.5% in solar LEC. The risks and uncertainty associated with this innovation is also high. Large area heliostats provide a larger cost reduction potential with lower uncertainty and within a shorter time frame. Front surface mirrors in conjunction with innovative structures show a LEC reduction potential lower than ganged heliostats, the main uncertainty is their durability and long term stability. The impact of dust repellent mirrors and autonomous heliostats on LEC is comparatively small. Dust repellent mirrors are assumed to have higher mean reflectivity due to the lower soiling and they need less cleaning, which results in a lower number of maintenance personnel. A thermal storage would increase the solar fraction and reduce the solar LEC. At the current level of cost it would increase the fossil LEC since the fossil capacity factor decreases.
Increased receiver temperature again leads to a higher solar fraction with increased fossil LEC compared to the reference case. If the minimization of carbon dioxide emissions is one of the targets, an increased solar fraction is important issue.

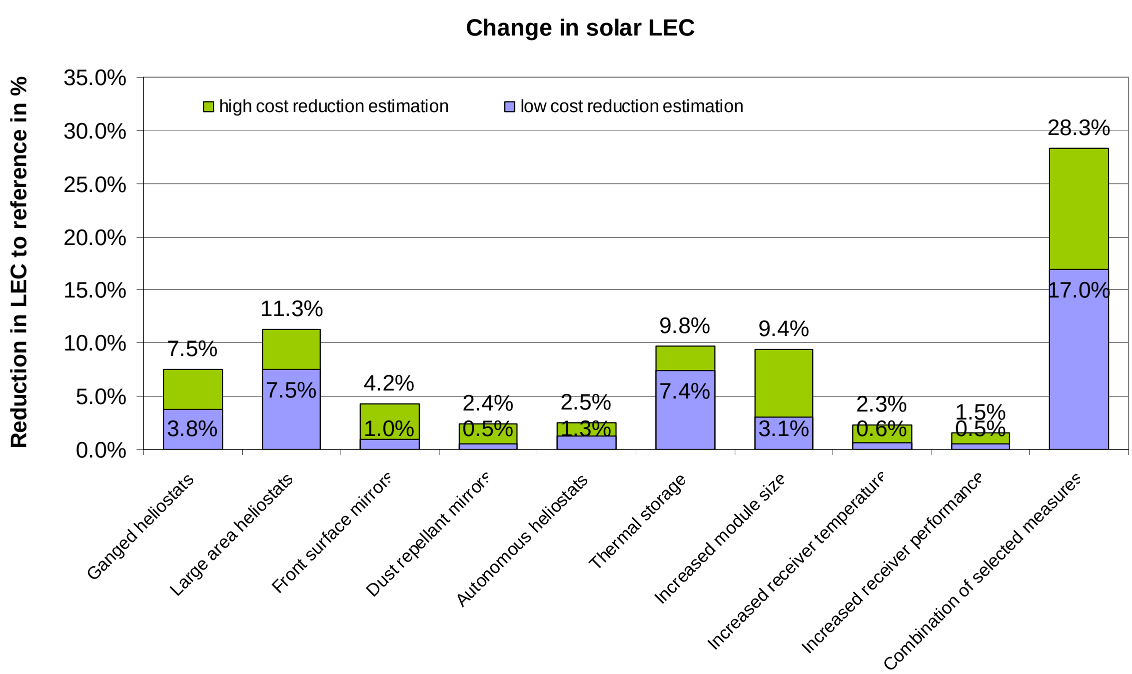


Figure 7-8: Impact of innovations on solar LEC for the SCR pressurized air gas turbine system (full load from 9 a.m. to 11 p.m.).

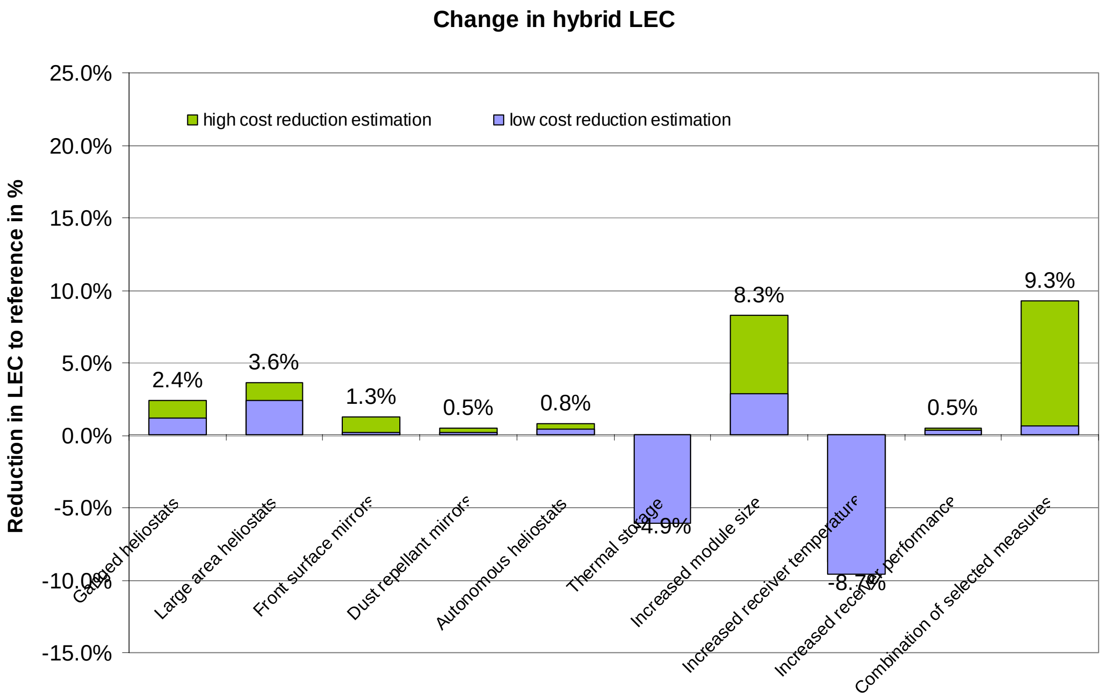


Figure 7-9: Impact of innovations on hybrid LEC for the SCR pressurized air gas turbine system (full load from 9 a.m. to 11 p.m.).

Table 7-7: Main input data for the SCR pressurized air gas turbine system and the considered innovations.

Innovation		**Reference system**	**Ganged heliostats**	**Large area heliostats**	**Front surface mirrors**	**Dust repellent mirrors**	**Autonomous heliostats**	**Thermal storage**	**Increased module size**	**Increased receiver tempe-rature**	**Increased receiver perfor-mance**	**Combi-nation of selected measures**
Technical Input												
aperture area of the solar field	m²	152000	152000	152000	152000	152000	152000	229524	152000	253536	146988	229520
average reflectivity	-	0.88	0.88	0.88	0.88 / 0.89	0.88 / 0.91	0.88	0.88	0.87 / 0.88	0.88	0.89 / 0.91	0.87 / 0.88
air temperature at receiver exit	°C	800	800	800	800	800	800	800	800	1000	800	800
design net electrical output	kW	4*14683	4*14683	4*14683	4*14683	4*14683	4*14683	4*14683	64400	4*14683	4*14683	64400
design efficiency of the power block	-	0.447	0.447	0.447	0.447	0.447	0.447	0.447	0.46 / 0.490	0.445	0.447	0.46 / 0.487
storage capacity	h	0	0	0	0	0	0	3	0	0	0	3
thermal capacity of the storage	kWh	0	0	0	0	0	0	238160	0	0	0	238160
fluid temperature at storage discharging	°C	750	750	750	750	750	750	750	750	750	750	750
O&M Input												
number of persons power plant		30	30	30	30	30	30	30	30	30	30	30
Specific number of persons field maintenance	1/1000m²	0.030	0.030	0.030	0.030	0.025 / 0.02	0.030	0.030	0.030	0.030	0.030	0.025 / 0.02
Cost input												
specific investment for solar field	€/m²	150	135 / 120	120 / 105	143 / 135	150	145 / 140	150	150	150	150	120 / 105
spec. investment for power block	€/kW$_e$	700	700	700	700	700	700	700	650 / 550	700	700	650 / 550
spec. investment for storage	€/kWh$_{th}$	50	50	50	50	50	50	30 / 20	50	50	50	30 / 20
spec. investment cost for receiver	€/kW$_{th}$	150	150	150	150	150	150	150	150	180 / 165	150	150
total investment cost for towers	M€	7.3	7.3	7.3	7.3	7.3	7.3	7.3	5.8 / 3.6	7.3	7.3	5.8 / 3.6

7.7. Dish-Engine Systems Using Stirling or Brayton Cycles

The basic system characteristics of the dish-Engine system considered in this study are:

- Fuel hybridized system providing 100% of the power from sunlight at design conditions
- A single module size can be 10-50kWe (the reference system uses about 20 kWe), hence a large number of modules is required for a utility-scale plant
- The dish optics provide a large solar capacity factor relative to trough and SCR systems
- No storage option is used with the dish/engine systems
- A dish/Stirling is used as a reference, and a dish/Brayton system, where a gas-turbine replaces the Stirling engine is evaluated as a possible innovation.

Other aspects of the system are similar to those of the SCR with a hybrid, solarized gas-turbine described in the previous section. The innovations and improvements proposed for the dish/engine systems are:

1. Improve system availability and reduced O&M costs
2. Reduced Stirling engine cost
3. Increased engine efficiency
4. Increased size and reduce cost of the dish concentrator
5. Reduced receiver cost
6. Increased mirror reflectivity and dish tracking accuracy
7. Replacement of the Stirling engine with a gas-turbine (Brayton cycle)
8. Combination of the various innovation

Table 7-8 lists the main calculation input parameters and various innovation assumptions.

Figure 7-10 and Figure 7-11 show the effect of various innovations and improvements on the LEC of the solar part, and the entire dish/engine system, respectively. Two sets of assumptions were used in the calculations. The “high cost reduction estimates” are calculated using the values listed in Table 7-8, where as the “low cost reduction estimates” assume a smaller effect of the innovation (i.e. a smaller cost reduction, or efficiency increase due to the improvements of a given component). As seen in the Figures, the combined effect of all of these innovations yields a 55% to 66% reduction of the solar LEC, and 47%-58% reduction of the entire system LEC. The greatest impact comes from the mass production which brings down the specific costs per installed power from 8000 €/kW for the reference case to about 4600 €/kW. The lowest expected LEC, based on the combined effect of several innovations and improvement can be around 12 €cents/kWh (installed costs of 2600 €/kW). The largest contributors to cost reduction are improvement of system availability and reduced O&M costs, reduced dish-concentrator cost, and replacement of the Stirling with a Brayton engine, assuming the latter has similar efficiency, lower cost, higher reliability and lower O&M.

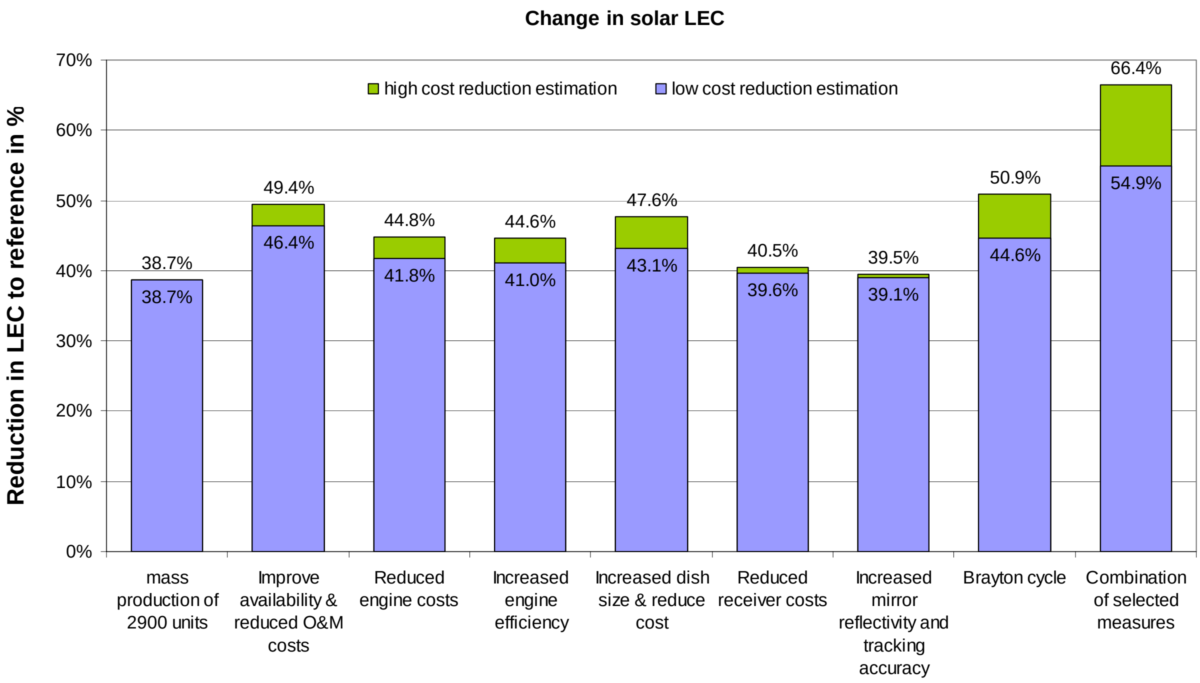


Figure 7-10: Impact of innovations on solar LEC for the dish/engine system (full load from 9 a.m. to 11 p.m.).

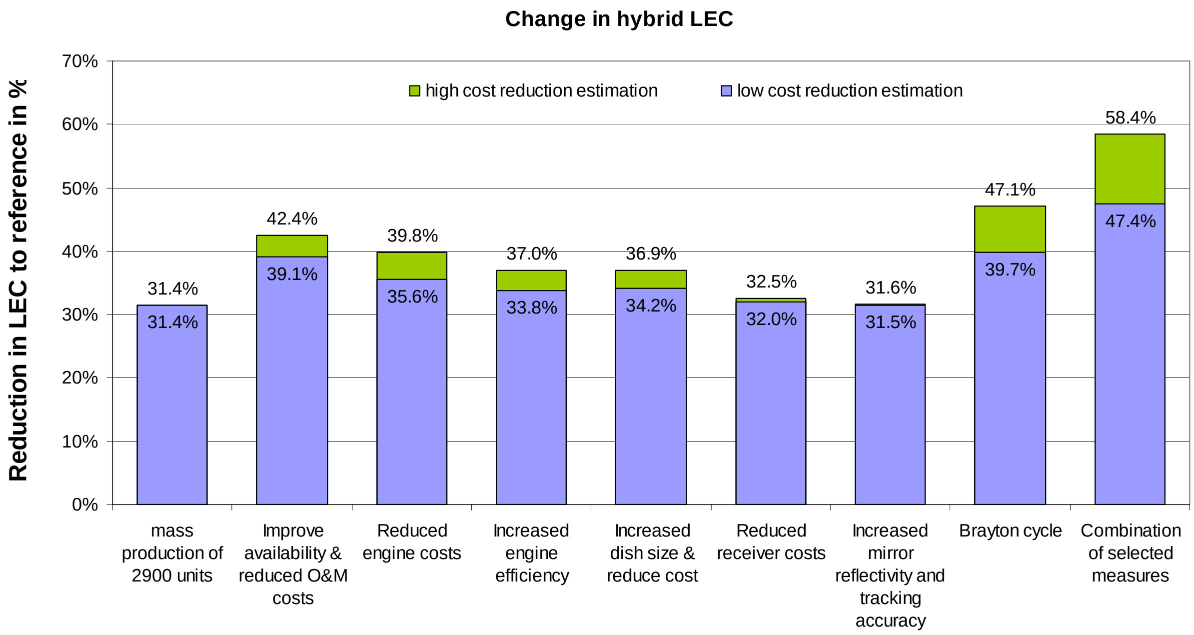


Figure 7-11: Impact of innovations on hybrid LEC for the dish/engine system (full load from 9 a.m. to 11 p.m.).

Table 7-8: Main input data for a 50 MW solar-fuel hybrid dish/engine system and the innovations considered.

Innovation		**Reference system Dish/Stirling**	**Mass production of 2900 units**	**Improve availability & reduced O&M costs**	**Reduced engine costs**	**Increased engine efficiency**	**Increased dish size & reduce cost**	**Reduced receiver costs**	**Increased mirror reflectivity and tracking accuracy**	**Brayton cycle**	**Combination of selected measures**
Technical Input											
aperture area of the solar field	m^2	350,000	350,000	350,000	350,000	310,000/ 330,000	350,000	350,000	350,000	380,000	355,000/ 370,000
average reflectivity	-	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.9 / 0.89	0.88	0.9 / 0.89
reflective area of one dish	m2	120.4	120.4	120.4	120.4	120.4	400	120.4	120.4	121.4	400
design net electrical output	kW	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
design efficiency of the plant	-	0.2145	0.2145	0.2145	0.2145	0.25 / 0.2273	0.2145	0.2145	0.2145	0.1956	0.2083 / 0.20
design solar thermal input	kWt	233,125	233,125	233,125	233,125	200,000 / 220,000	233,125	233,125	233,125	255,569	240,000 / 250,000
mean plant availability		0.85	0.85	0.95 / 0.9	0.85	0.85	0.85	0.85	0.85	0.95 / 0.9	0.95 / 0.9
O&M Input											
number of persons power plant		30	30	30	30	30	30	30	30	30	30
Specific number of persons field maintenance	$1/1000m^2$	0.060	0.060	0.03 / 0.035	0.060	0.060	0.060	0.060	0.060	0.060	0.03 / 0.035
O&M Equipment costs percentage of investment	per a	1.5%	1.5%	1.0%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.0%
power block O&M fix	Euro/kW	40	40	27	40	40	40	40	40	40	27
power block O&M variable	Euro/MWh	4.5	4.5	3	4.5	4.5	4.5	4.5	4.5	4.5	3
Cost input											
specific investment for solar field	€/m^2	440.0	250.0	250.0	250.0	250.0	180 / 215	250.0	250.0	250.0	180 / 215
spec. investment for power block	€/kW_e	3000	1750	1750	1000 / 1375	1750	1750	1750	1750	600 / 1000	600 / 1000
spec. investment cost for receiver	€/kW_{th}	45	71	71	71	71	71	50 / 60	71	59 / 65	50 / 60

8. Conclusions and recommendations

Many of the systems considered here are planned for commercial deployment in Spain, which recently enacted an incentive of around **21 cents€/kWh** for solar thermal electricity. The most mature technology today is the parabolic trough system that uses thermal oil as a heat transfer medium. Several **50 MW$_{el}$** units using thermal energy storage based on molten salt are currently planned in Spain. The present ECOSTAR evaluation estimates levelized electricity cost of **17-18 cents€/kWh** for these initial systems, assuming a load demand between 9:00 a.m. and 11:00 p.m. These cost estimates may deviate from electricity revenues needed for the first commercial plants in Spain because they were evaluated using a simplified methodology including the financing assumptions recommended by the IEA for comparative studies like this. The other technologies analyzed are currently planned in significantly smaller pilot scale of up to **15 MW$_{el}$**. The LEC is significantly higher for these small systems ranging from **19 to 28 cents/kWh**. Assuming that several of the smaller systems are built at the same site to achieve a power level of 50 MW and take benefit of a similar O&M effort as the larger plants, LEC estimates of all of the systems also range between 15 and 20 cents/kWh. The systems achieve a **solar capacity factor of up to 30%** under these conditions (depending on the availability of storage). One significant exception is the integration of solar energy into a gas turbine / combined cycle, which at the current status of technology can only provide a solar capacity factor of 11% and needs significant fossil fuel (20% -25 % annual solar share depending on load curve) but offers **LEC of below 9 cents/kWh for the hybrid operation**[20] (equivalent to 14 cents/kWh for the solar LEC). Due to the low specific investment cost of the gas turbine / combined cycle together with a high efficiency, the system is specifically attractive for hybrid operation. Further development of the receiver technology can increase the solar share significantly in the future.

Since the absolute cost data for each of the reference systems are relatively close and are based on a different level of maturity, **choosing technologies for R&D prioritization** (e.g. troughs vs. towers) **doesn't appear feasible**. This competition between technologies will be left to industrial entrepreneurship and market forces. However, the evaluation has identified the major cost reduction drivers for each of the considered reference systems and has identified the impact of technical innovation approaches.

For all systems considered technical innovations were identified and translated into component cost and performance estimates to calculate LEC. The most promising options were combined to evaluate the overall cost reduction potential. Based on the limited number of approaches suggested in the scope of this study already cost reduction of 25 - 35% appears very feasible for most of the technologies (Figure 8-1). These figures do not include effects of volume production or scaling of the power size of the plants beyond 50 MW. For parabolic trough technology the Sargent & Lundy study [1] has estimated a cost reduction of 14 % by larger power blocks (400 MW) and 17% by volume production effects when installing 600 MW per year. Assuming similar figures also for the other technologies, an **overall cost reduction of 55 – 65%** (see Figure 8-2) can be estimated in the next 15 years. This would lead to levelized cost of electricity in **Southern Spain of around 6.5 cents/kWh** and down to **5 cents/kWh in high insolation areas** (see Figure 8-3) like those at the southern shore of the Mediterranean sea and would represent competitive cost for mid-load power (without CO_2 emissions).

[20] At a fuel price of 15 €/MWh

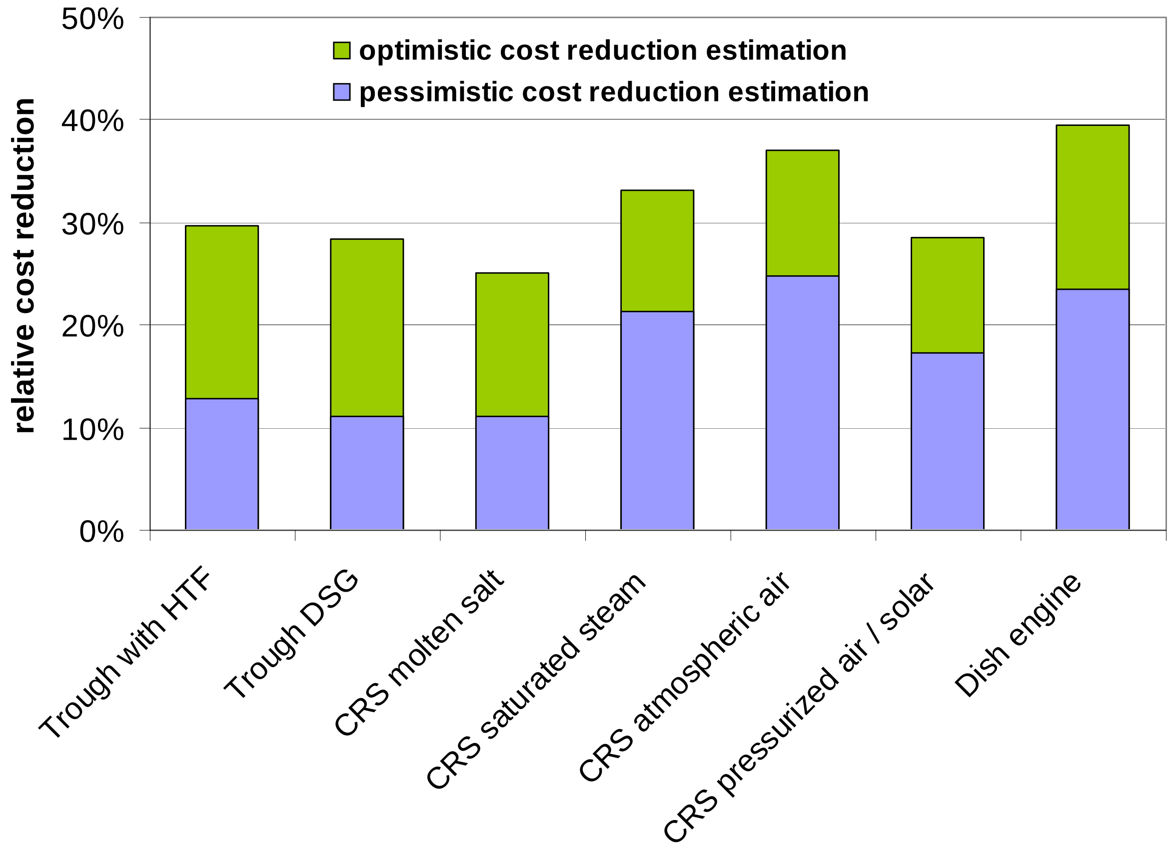


Figure 8-1: Innovation driven cost reduction potential for the 7 CSP technologies investigated in this study based on the LEC for the 50 MW_e reference system and assuming a combination of selected innovations for each system.

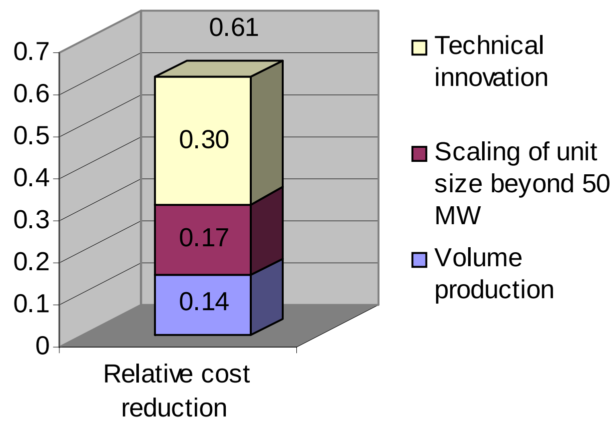


Figure 8-2: Potential relative reduction of LEC by innovations, scaling and series production through 2020 for the parabolic trough/HTF system compared to today's LEC

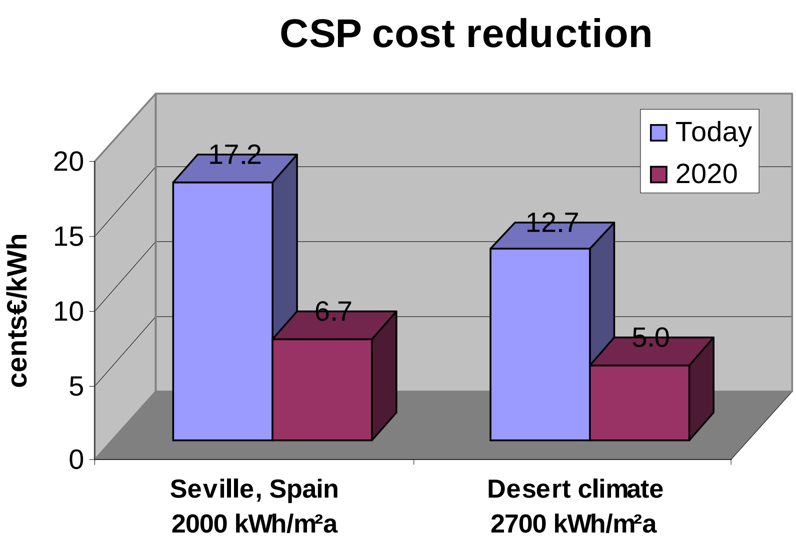


Figure 8-3: Predicted LEC today and in 2020 in cents/kWh for CSP technology for two different climate conditions. Shown for the parabolic trough / HTF system.

Although, it can not be predicted today which of the technologies may finally achieve what market share, or which options may eventually dropped, specific characteristics, benefits and drawbacks as well as development needs can be summarized:

Parabolic Trough Technology using thermal oil as heat transfer fluid
As mentioned above, parabolic trough systems using thermal oil can be considered as most mature CSP technology due to the experience with nine commercial plants in California that have already run through a significant learning curve. This is the reason why it appears feasible today to build 50 MW units with a total cost of more than 200 Mio. Euro. Major perceived risks are associated with the molten salt thermal energy storage system, which is scaled by a factor of ten compared to previous experiences. The optical characteristic of the plant clearly favours summer peak load production. Winter performance in south European latitudes is rather low. Parabolic trough technology can only be deployed in very flat area with slope below 3% whereas CRS show a higher degree of flexibility.
Major limitations of today's trough systems are caused by the synthetic thermal oil, which is costly, may raise environmental concerns and is limited in its application temperature. Somehow linked to this is the availability and costs of thermal energy storage for parabolic trough technology. A temperature rise of only 100 K from collector inlet to outlet lead to significant higher storage volumes and costs compared to some CRS concepts. The collector as the dominant cost fraction of the whole plant - although representing today the fourth commercial generation – is considered to still have a potential for slight performance improvement and significant cost reduction specifically based on new materials for support structure and reflector (up to 15% of the LEC). Depending on the load curve of the system, advanced storage options may also significantly (up to 10%) contribute to the cost reduction of the plant. The development of new HTF fluids with higher temperature stability can also contribute to the cost reduction (3%). Reducing the pumping power (e.g. by a modified receiver piping) may add to the reduction in the same order of magnitude. Combination of these measures may lead to cost reduction of up to 30%.

In terms of risk, the development of new collectors is considered to be linked with lowest scale-up effort, due to the modular concept. Starting form a small prototype, a reference loop added to an existing parabolic trough plant is the only step for a commercial qualification of a new design. The development of storage systems needs several scale-up steps linked with significant cost and time. New HTF fluids need long-term aging test under non-commercial boundary conditions before a replacement may be achieved. It is not clear whether the use of the new fluids in solar power plants by sufficient driver for the chemical industry to develop new HTF fluids.

Parabolic Trough Technology using Direct Steam Generation
DSG systems may be considered as an evolution of parabolic trough systems using thermal oil. They share most of the benefits and drawbacks. However DSG collectors do not face the limits of the thermal oil. This saves costs, reduces heat losses, pumping parasitics and eliminates the temperature limit. Today, the controlled operation of several parallel rows is perceived as highest risk. In addition no realistic storage option for DSG systems exists today. Nevertheless ECOSTAR analysis has shown that a 50 MW plant using DSG without storage at the same temperatures level than the thermal oil collector, may lead to a reduction in LEC compared to the parabolic trough technology reference system. An increase in temperature, and a storage at similar cost than for thermal oil today can lead to a reduction of more than 10 % in LEC. An improvement of the collector performance and cost as discussed in the section above is applicable here too, so that a cost reduction up to 35% compared to today's parabolic trough concept is achievable.
In terms of risk, it appears suitable to operate several rows of DSG collectors parallel to existing parabolic trough fields, to validate costs, performance and operational experience before larger DSG plants may be erected.
Linear Fresnel collectors are another concept for DSG collectors, which may also contribute to the cost reduction. A lower optical performance has to be offset by lower investment costs in the collector due its more standardized components. ECOSTAR has estimated that under southern European conditions Fresnel-collectors need approximately 65 -70% of the specific collectors costs to break even with DSG parabolic trough systems. Up to now, the performance of Fresnel systems is evaluated only on a theoretical basis, so that a verification of both installation cost and system performance is needed. A reference module similar to the DSG system installed at the Plataforma Solar de Almería is required as a first step.

CRS using molten salt
With respect to Central Receiver Systems, molten salt technology is the most developed one today due to its 10 MW pilot plant experience in the US. Based on the cost estimates provided by the US colleagues and on the ECOSTAR evaluation, even the small scale concepts (15 MW) looks relatively attractive in terms of costs (LEC 18-19 cents/kWh). This is mainly attributed to very attractive costs for the thermal energy storage which benefit from a three times larger temperature rise in the CRS compared to the parabolic trough system Additionally a higher annual capacity factor is possible for CRS due the smaller difference between summer and winter performance compared to parabolic trough systems. Largest risk is associated with the expected plant availability which could not be proved to be high in the Solar Two demonstration due to a variety of problems linked to the molten salt and the aged heliostat field. However technical solutions have been identified addressing these issues.
Major aspect of cost reduction is the scaling to a single 50 MW module to take benefit from higher cycle performances (which are not available at small steam turbine systems) (up to 10% LEC cost reduction) as well as a significant cost reduction in the heliostat cost e.g. by

very large heliostats or ganged heliostat concepts (up to 10%). The storage cost can be further reduced replacing the two tank storage concept by a single tank thermocline storage concept (1% LEC). Overall a cost reduction up to 25% by innovations brings molten salt technology in the similar cost range than DSG parabolic trough may enter.
The risk associated with plant availability can only be resolved in a pilot plant, like the one prepared for Spain. At the end, this risk will lead to surcharges in the prices not considered in this analysis.
The development of innovative heliostats as a major driver for cost reduction is considered to be linked with a relatively small scale-up effort, due to the modular concept. Starting from a small prototype, some heliostats may be added to an existing power tower as the only step for a commercial qualification of a new design. However, companies which invest into heliostat development need to see a significant market growth for CRS systems, what is currently less obvious than for parabolic troughs. This may impact the development speed in specific components also for other CRS systems.

CRS using saturated steam

Steam receivers that have been built in several demonstration plants showed operational difficulties in the past mainly attributed to the superheating of steam. Saturated steam is considered as low risk approach. Design concepts are based on experience in steam generator technology. This lead to relatively low investment cost for the receiver and combined with the low temperature to a high receiver performance. On the other hand a low cycle performance, no cheap storage option, and high maintenance cost for the power cycle are the consequence. As long as the steam will not be superheated, system performance can hardly be improved. LEC for an 11 MW plant are around 24 cents/kWh a series of 5 systems at the same site lead to LEC 17-18 cents/kWh.
Besides innovation on the concentrator, valuable for all CSP systems, the highest impact of innovations is linked to a receiver superheater, to a scaling of the system up to one 50 MW plant and to a low cost thermal energy storage.
The challenges are significant because the problem of superheated steam receivers is not solved today although it has been addressed in previous CRS demonstration plants. Scaling the cavity receiver concept to larger power levels has some constraints. The low-cost storage of steam, also needed for DSG technology, is also not solved today. Unlike other CRS technology approaches studied here, which show the benefit of a low cost storage option like molten salt, or the benefit of high temperature cycles like air receivers, the steam concept doesn't present any intrinsic benefits compared to the parabolic trough / Fresnel approach that may justify the higher effort of a two-dimensional concentration. However, the technology is the first in Spain which is under erecting, which is an essential step forward to reduce the risk for follow on projects. If the above mentioned innovations will be achieved, ECOSTAR analyses show that LEC cost reductions up to 33% are feasible leading again to similar cost figures than for molten salt or parabolic trough DSG systems.

CSR using atmospheric air

Atmospheric air receiver technology is a fail-safe concept with low thermal inertia that has proven operation in a 3 MW_{th} pilot test. Therefore, high availability figures for the plant are expected. Cost estimates for the first 10 MW commercial system and for a replication of 5 systems at the same site lead to slightly higher cost estimates than for the saturated steam receiver. Solar-to-electric efficiency is estimated to 13.5%, which is considered as quite low for CRS systems. This is due to the relative low receiver performance of the current state-of-the-art volumetric receiver systems, which are less far developed than molten salt or saturated steam receiver technology and show intrinsic air return losses. Efficiency improvements should, therefore first concentrate on the receiver and the air circuit.

Compared to other systems the cost of the heat storage is also relatively high although the storage concept is very simple. This may result from the fact that the costs provided by industry include high additional risk surcharges since the requested sizes are not typical in other applications for the first of its-kind demonstration systems.
Besides cost reduction in the concentrator, the scaling to a single 50 MW unit opening the opportunity for more efficient cycle (than those available at the small size) together with a reduction of the receiver losses and the development of low cost thermal energy storage is the spectrum of essential R&D needs to bring the cost figures down by up to 36% of today's value, thus entering into a similar range as the concepts mentioned above.
However, in the first step a small full scale prototype plant must be built in order to prove cost and performance as well as operational behaviour. Receiver and concentrator development can be performed on a modular basis which limits the amount of scale-up steps. Single receiver modules can be tested in a larger scale receiver, without interfering significantly with the rest of the system. Storage development needs more complex scale-up approaches, resulting in longer development time and higher development costs. The integration into a larger power block benefits from the modular receivers design. The steam generator technology can be based on conventional heat recovery boilers, which are available in large scale power sizes, so that the scaling risk is considered to be moderate.

CRS using pressurized air receiver
Pressurized air receiver technology is an early stage of development with the long term target to provide high temperature to combined cycle power plants that convert the solar and optionally fossil fuel at a very high efficiency. At the current status of technology the receiver is limited in the temperature to approximately 800°C so that fossil fuel is used to achieve common gas turbine inlet temperatures. This leads to relatively low solar contributions (20-25%). The development of receivers with higher temperatures may overcome this constraint in the future. The benefit of this approach is the relatively low solar/fossil LEC (< 9 cents/kWh for 4 replicated 15 MW systems at a fuel price of 15 €/MW). Other solar systems operated in hybrid operation mode may not achieve the same low figures due to the lower fossil to electric efficiency.
In addition to a reduction in concentrator costs, a larger module size, in this case one 50 MW_{el} power block instead of four single units, shows the largest impact on the LEC because it gives access to larger more efficient gas turbines. Lower investment in conjunction with higher performance leads to benefits for both the solar and the fossil operation. The integration of a solar receiver into a larger gas turbine system is a big challenge and associated with high uncertainties and risks. However, in this concept it is an essential step to reduce the cost significantly.
Solar fossil generation cost can be reduced by 14% (equivalent to a reduction of 33% in the solar electricity costs). At this level and under excellent insolation conditions, solar energy input becomes more profitable than fossil operation. Although the concept is generally attractive providing firm capacity at low LEC, low investment and low CO_2 emissions, current compensation schemes in Spain do not support hybrid operation with a fossil of more than 15%, so that market penetration of this approach is currently difficult to achieve. Decentralized applications with heat and power demand are currently studied as an option for Niche market applications.

Dish Engine Systems
Extensive effort has been devoted to the development of dish/Stirling systems for more than two decades. Several prototype systems, each producing 10-25 kWe, were erected and tested for thousands of hours by different developers. Fuel hybridization was introduced to the more recent systems. These systems demonstrated very high overall efficiency at

design point as well as on an annual basis, relative to other solar-electric systems. They also provide relatively high annual energy output per unit of reflector area. However, the cost of the concentrating dish and the Stirling engine are presently very high, leading to a current system cost of about 8000 €/kWe. Furthermore, the longevity and reliability of the solarized Kinematics Stirling engines used in the above systems were insufficient, instigating low availability and high O&M costs.

Based on assessments provided by the various developers, the ECOSTAR study estimates that the production of nearly 3000 dish/engine units, required for a 50MWe facility, would reduce the system cost by over 40%, to less than 4700 €/kWe. It is further estimated that the system availability would improve and the O&M cost would be reduced during this commercialization phase. The LEC reduction resulting from a 50 MWe production would be almost 40%.

Innovative developments leading to a larger dish-concentrator size and replacement of the Stirling engine with a small, recuperated gas turbine (solarized microturbine) would further reduce system cost and LEC. The combined LEC cost reduction due to these innovations and the number of produced systems for a 50 MWe plant would be about 60%, leading to LEC value of under 0.12 €/kWh for the entire dish/engine system. Further cost reduction should occur as more systems are installed and operated. The modular nature of dish/engine systems offers flexibility of plant size and enables partial generation while the plant is constructed.

8.1. Research Priorities

The various innovations aspects have different impact for on the LEC reduction of the 7 systems investigated. The **innovation potential** with the highest impact on CSP-cost reduction is presented for each of the technologies in the following table

Technology	Priority A	ΔLEC	Priority B	ΔLEC	Priority C	ΔLEC
Trough using oil	concentrator structure and assembly	7-11%	Low cost storage system advanced reflectors and absorber	3-6 % 2-6%	increase HTF Temp reduce parasitics	1 - 3 % 2 – 3 %
Trough DSG	scale increased to 50 MW system Concentrator structure, and assembly	14 % 7-11%	Advanced Storage advanced reflectors and absorber	3-6% 2-6%	Increase HTF Temp reduce parasitics	1 - 3 % 2 – 3 %
SCR Salt	scale increased to 50 MW heliostat size, structure,	3 -11% 7 -11%	Advanced mirrors	2 -6%	advanced storage	0 -1 %
SCR Steam	scale increased to 50 MW heliostat size, structure,	6-11% 7 -11%	superheated steam advanced storage	6 -10% 5-7%	advanced mirrors	2 -6%
SCR Atmosph. Air	scale increased to 50 MW heliostat size, structure,	8 -14% 7 -11%	advanced storage increased receiver performance	4-9% 3-7%	advanced mirrors	2 -6%
SCR Hybrid GT	Heliostat size, structure, Include Thermal Storage	7 -11 % 7 –10%	scale increased to 50 MW	3- 9%	advanced mirrors increased rec. performance.	2 -6% 1- 2%
Dish	mass production for 50 MW	38 %	improve availab and red. O&M Brayton instead of Stirling Increased unit size	8-11% 6-12% 5-9%	increased engine eff. reduced engine cost advanced mirror and tracking	2-6% 2-6% 0-1%

Summarizing the detailed findings for the individual systems we may see that improvements in the **concentrator** performance and cost most drastically impact the LEC figures. Since the concentrator is a modular component, development of prototypes and benchmarks of these innovations in real solar power plant operation condition in parallel with state of the art technology is a straight forward strategy. New reflector materials should be low cost and have the following traits:

- good outdoor durability,
- high solar reflectivity (>92%) for wave lengths within the range: 300 nm - 2500 nm,
- good mechanical resistance to withstand periodical washing,
- low soiling coefficient (<0.15%, similar to that of the back-silvered glass mirrors).

The supporting structure of the concentrators also needs improvement. New structures should fulfil the following requisites:

- lower weight
- higher stiffness
- More accurate tracking
- Simplified assembly

Scaling to larger power cycles is an essential step for all technologies except for parabolic trough systems using thermal oil, which have already gone through the scaling in the nine SEFS installations in California starting at 14 MWe and ending at 80 MWe. Scaling reduces unit investment cost, unit operation and maintenance costs, and increases performance. The integration into larger cycles specifically for power tower systems means a significant challenge due to the less modular design. Here the development of low-risk scale-up concepts is still lacking.

Storage Systems are a second key factor for cost reduction of solar power plants. Development needs are very much linked to the specific requirements of the systems in terms of the used heat transfer medium and the required temperature. In general storage development needs several scale-up steps generally linked to an extended development time before a market acceptance can be reached. Requirements for storage systems are

- Efficient in terms of energy and exergy losses
- Low cost
- Long service life
- Low parasitic power requirements

Especially challenging is the development of storage systems for high pressure steam and pressurized, high temperature air that would lead to a significant drop in electricity costs.
Higher temperatures also lead in many cases to higher system performance. The current status of receiver technology however, does not exploit the full performance potential. Significant improvements in the performance of high temperature receivers are possible, whereas the room for performance improvements in the temperature range below 400° is relatively small (cost improvements are possible).

8.2. How to reach the CSP Vision

The detailed analysis has identified a number of innovations most relevant for cost reduction. In order to transfer this knowledge first into products, then into a continuous deployment of CSP technology a number of key issues must be addressed:

Increasing RTD efforts

The amount of RTD funds by the European Union dedicated to CSP was small compared to other technologies like wind, photovoltaics and biomass. However, they have been sufficient to support a new start-up of CSP technology in Europe (specifically in Spain and Italy). Several hundred MWs of installed capacity appear likely to be installed by 2010. If the predicted cost reductions triggered by technical innovations shall play off its full potential in the next 15 years a significant increase in RTD efforts is required to be introduced in the 7th Framework Programme. This money appears to be well invested in a low cost solar technology providing dispatch-able bulk electricity.

Alignment of RTD strategies and goals
ECOSTAR aims to initialize a much stronger long-term European integration effect than can be achieved by co-operation on a project-by-project basis. It will initiate the process to agree on common goals and priorities and utilize national and European resources most effectively to achieve them. All European Research centers involved in ECOSTAR manage a significant institutional (or sometimes even national) budget for CSP research. A joint European roadmap shall be the starting point to adjust their individual program goals and priorities in order to achieve the highest impact with their limited resources. This will be the basis to implement the existing European facilities of various powers and concentration factors, the existing tools and human resources most efficiently in future projects and to streamline the national development activities by setting common priorities and goals. One important result is the formation of the SOLLAB alliance formed by CIEMAT, CNRS, DLR and ETH to reach this goal. It is recommended to support the extension of such an R&D platform as a European network of excellence.

Involving further excellence
Further expertise is needed. Until now only a small number of companies with specific expertise and a variety of research institutions were involved in European R&D projects in this field. Further expertise is required:

- Large companies capable and used to lead EPC contracts of several hundred Million Euro from the power sector could bring a better market knowledge and cover the question of integration of the solar system with the power cycle more thoroughly,
- Companies specialized in glass, reflectors, light weight structures, drives, outdoor plastic etc. could provide expertise in concentrators,
- Chemical industry could support the development of improved HTF or storage media,
- Large construction companies capable of designing and building storage containers which are able to handle and transport hot fluids,
- Companies specialized in mass production and logistics (like car manufacturers) could optimize the production process and minimize manufacturing cost,
- Technical supervising companies to achieve a high quality control to reduce risks specifically in the scaling process.

Building a global market
CSP is currently emerging in many countries of the World; in Spain the situation is one of the most far developed. **A key to success is to build a sustainable market situation**. In many of the countries, the progress is slow in part due to non-technical barriers. In order to generate a global market, it is important to take the lessons learned in the countries where CSP deployment is successful and transfer them to other countries. Such a market would have faster growth, would attract larger global companies, and would lead to costs increasingly competitive with conventional sources. The CSP global market initiative (GMI; www.solarpaces.org/gmi.htm) is an essential step that needs support of the European Union.

Setting the political framework

- CSP is inadequately considered in most European renewable electricity incentive schemes. Countries like Portugal, Greece Malta and Italy having a significant solar resource may consider opening their incentive schemes to CSP technologies.
- Consider opening the European market for the import of solar electric from Northern Africa. Higher solar resource levels may over-compensate the additional transport cost and the deployment of the technology would help to support the political stability in this region.
- Hybrid operation of CSP systems is of high benefit for both the cost of the solar electricity as well as for the stability of the electrical grid. The legal frameworks should be more flexible to allow this option.
- Scaling up CSP to larger power block sizes is an essential step to reduce electricity costs. Incentive schemes should not limit the upper power level to fully exploit the cost reduction potential.

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