Universität Stuttgart
Institut für Energiewirtschaft und Rationelle Energieanwendung IER

Technical and economical analysis of future perspectives of solar thermal power plants

Francesco La Porta

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1 Introduction

Constraints in mineral oil and natural gas supplies and increasing demand for electricity have caused many concerns on future power supply around the world. And as the population in many countries continues to grow, this demand will continue to increase. One of the renewable source of energy which can significantly contribute to this future energy demand within the next 15 years is the Solar Concentrated Power Systems (CSP). In this work I will analyse the three different CSP technologies, their present status and their future technical innovations. I will afterwards analyse their actual investment and O&M costs, their future costs' previsions and finally the actual and future Levelised Energy Costs (LEC) of each system. In this way it will be possible to make an economical comparison of the different CSP concepts.

All solar technologies make use of sunlight, but they differ in the ways they capture and use solar energy to produce heat or electricity. Most solar water- and space-heating technologies, for example, use sunlight directly to produce low-temperature heat, while photovoltaic (PV) systems convert sunlight directly to electricity using semiconductor materials in solar panels. The difference of concentrating solar power (CSP) technologies with those systems is that they first concentrate the sun's energy using reflective devices such as troughs or mirror panels and then the resulting concentrated heat energy is transferred to a heat-transfer medium (HTF), which is used to power a conventional turbine and produce electricity.

There are three main CSP systems: the parabolic trough, the solar tower and the solar dish. Trough technology (cp. **2.3**) is the most advanced one, since it has 354 MW_{el} of commercial experience during 20 years. Therefore there's a low technical and financial risk in developing near-term plants. For this reason these systems have received the greatest attention over the years. It is the simplest of the technologies and has the lowest efficiency, but economic factors are favourable thanks to the long commercial experience. On the other hand, tower technology (cp. **2.4**) has been successfully demonstrated with a conceptual and a pilot plant (Solar One and Solar Two). What this kind of technology needs is to proceed from demonstration to commercial development. Towers can be located, concerning economic performance, between dishes and troughs, even though they carry the best prospects for future economic success thanks to their big innovation's potential. Although a late starter, dish technology (cp. **2.5**) carries the best prospects for off-grid operation, as well as providing the highest temperatures and therefore the highest efficiency.

There are many reasons why CSP is so interesting and why it should play a major role in the future energy mix. Apart from the fact that solar energy is the most abundant renewable source of energy on earth, the technological advances in the past 3-4 decades have allowed CSP systems to reach a stage which indicates good potential to attain economic viability, given appropriate condition, in comparison with fossil sources. Today's CSP systems can convert solar energy to electricity more efficiently than ever before, they can be exported to the developing world and an additional advantage is their lack of significant environmental degradation. Since CSP systems produce both heat and electricity, they can be useful in some industrial applications, they have durability and low operation & maintenance costs. Another key competitive advantage of CSP systems is that they closely resemble the current power plants in some important ways. This means that most of the equipment now used for conventional power plants can also be used for CSP plants. CSP simply substitutes the use of combustible fossil fuels with concentrated solar power to produce electricity.

This is rather an evolutionary than a revolutionary approach which enables CSP systems to be easily integrated into the already existing electrical utility grid. Another important consequence of the low-tech profile of CSP systems is the less time required for the plant's construction. The Solar Energy Generating System (SEGS) plants in California were constructed in less than a year each. New plants could provide local jobs and a boost to the manufacturing economy. CSP systems are modular, therefore easy to scale-up, and vary in size from 10 kW_{el} to 80 MW_{el}. This means that they adapt well to decentralised generation systems or that they can be installed in hybrid applications to allow 24-hour operation.

The results of the present work show that the LEC costs (cp. **3.6**) of parabolic troughs and solar towers are still 3 - 5 times those of conventional plants; the costs of solar dishes can be even 8 times higher, even though this system is convenient for off-grid operation. It's necessary that some developers begin implementing this technology, thus it can benefit from the costs' reduction due to the economy of scale, which in this work is evaluated to be about 11 % each time the cumulative production is doubled. This work shows that, combining the effect of economy of scale and R&D work, the costs can be significantly reduced within 15 years (cf. **3.5**), but it is still difficult to predict when solar electricity will become competitive with the conventional generation.

Concentrating solar power is however approaching commercial viability, and the industry is actively seeking financing for commercial projects. Construction work of the first European commercial plant (the solar tower PS10) has already begun in Spain and up to ten other projects are currently under planning, at a total capital cost of more than 1.000 Mio euros. To ensure the success of initial power plants, the industry requires continuous financial support for research activities. A very important signal in this direction has been given last year by the Spanish Government with the Royal Decree 436/2004, which grants a bonus of about 0,18 $€_{05}$/kWh for electricity from CSP systems. This has caused a rush in order to secure the best sites. The Spanish successful initiative will boost the CSP market thus a significant deployment can take place and therefore the electricity generation costs will probably decrease. The hope is that following this example, similar actions will be taken by other countries around the world. Looking at a long-term perspective, in fact, a vision of an intercontinental electricity grid seems to be realistic, making solar power generation an important option not only for the countries of sun-belt regions.

2 The different types of concentrated solar power systems (CSP)

This chapter will give first overview of the basic physical principles of solar energy, like the difference between diffuse and direct radiation. Then the different ways this energy can be used will be shown. In particular, in this work the Concentrated Solar Power (CSP) systems will be analysed. After giving a first overview of the basic working principle of the different CSP systems, it will analyse the single technologies in detail: at first the chronology of their development, then their actual and future developments.

2.1 The solar energy

The sun delivers two forms of energy on the Earth: material radiation and electromagnetic radiation. For us only the electromagnetic one is important.

The "Solar constant" is defined as the amount of radiation which reaches perpendicularly a surface of 1 m^2 outside the atmosphere, i.e. 1370 W/m^2. The word Solar Constant means a great constancy of the extraterrestrial radiation. Over many years it fluctuates less than 0,1 %. Short-term fluctuations over days and weeks, even 3 %, are possible.

The global radiation on the earth is G_E:

$$G_E = I_0 * T_G$$

where I_0 is the solar constant and T_G is the Transmission factor.

When going through the atmosphere, radiation is weakened because of :

- Diffuse reflection.
  This is the scattering of radiation in all directions. Only the direction of propagation changes, the energy content remains constant.
- Selective absorption.

This is the absorption and conversion of solar energy into heat carried out by the different gases of the atmosphere /IER 2004/.

This means that only 45 % of the total incoming radiation manages to pass through the atmosphere and reaches the Earth surface, whereas about 30 % of it is rejected into the space. Therefore it is clear that only the remaining radiation, 25 %, can be used as of renewable energy (water, wind, biomass, etc).

If we look at the global distribution of the radiation (**Fig. 2-1**), we can see that radiation varies between 800 and 2200 $kWh/(m^2a)$.

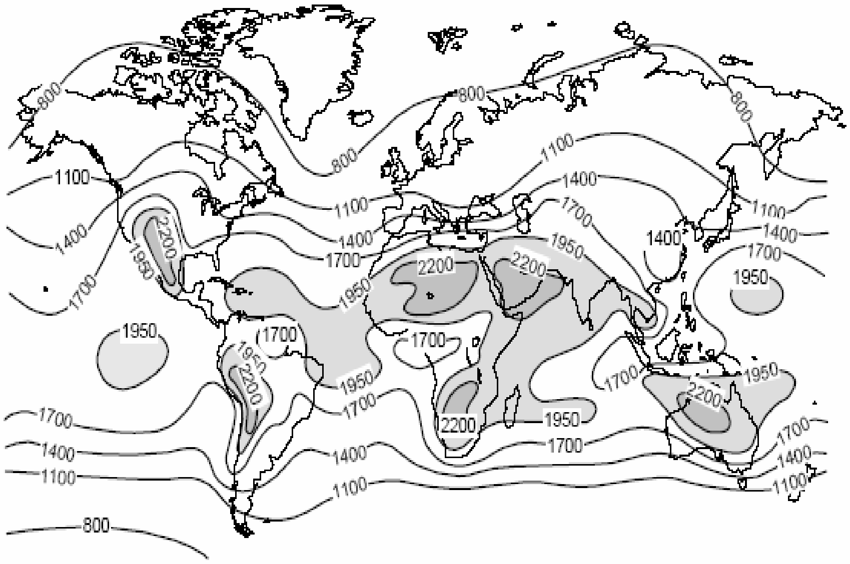

Fig. 2-1 Global distribution of solar radiation /IER 2004/

Of course the highest global radiation sums are in the deserts, high mountains regions and tableland of the earth.

2.1.1 Diffuse and direct radiation

Because of the scattering mechanisms of the atmosphere, two different kinds of radiation are possible:

- Direct radiation: this is the radiation coming directly from the sun and hitting a precise point on the Earth.
- Diffuse radiation: this is the radiation, scattered through the atmosphere, reaching indirectly a certain point on the Earth.

The sum of direct radiation $\mathbf{G_r}$ and diffuse radiation $\mathbf{G_f}$ is the global radiation $\mathbf{G_t}$:

$$\mathbf{G_t = G_r + G_f}$$

Reflection from the atmosphere and from the environment should also contribute to this sum, but these fractions are so small when compared to diffuse and direct radiation, that they are usually negligible /IER 2004/.

2.1.2 How solar radiation can be used

Solar energy can be used to produce heat and/or electricity. The first distinction is between thermal and photovoltaic use:

- In photovoltaic systems a direct active transformation into electricity takes place, since solar radiation hitting special layers make them releasing photons. However, they can’t produce heat.
- Solar thermal systems, as the name suggests, can produce heat. Electricity is always generated indirectly by heat, which produces steam driving the turbine.

Concerning solar thermal systems, a significant difference between concentrating and non-concentrating systems shall be made: non-concentrating collectors use both direct and diffuse radiation, but the heat produced can reach maximum temperatures of 200°C. If we want to achieve the high temperature necessary to produce steam, we have to use concentrated solar power systems, where only direct radiation is required.

An overview of the different ways of using solar energy can be seen in the following figure **Fig. 2-2**:

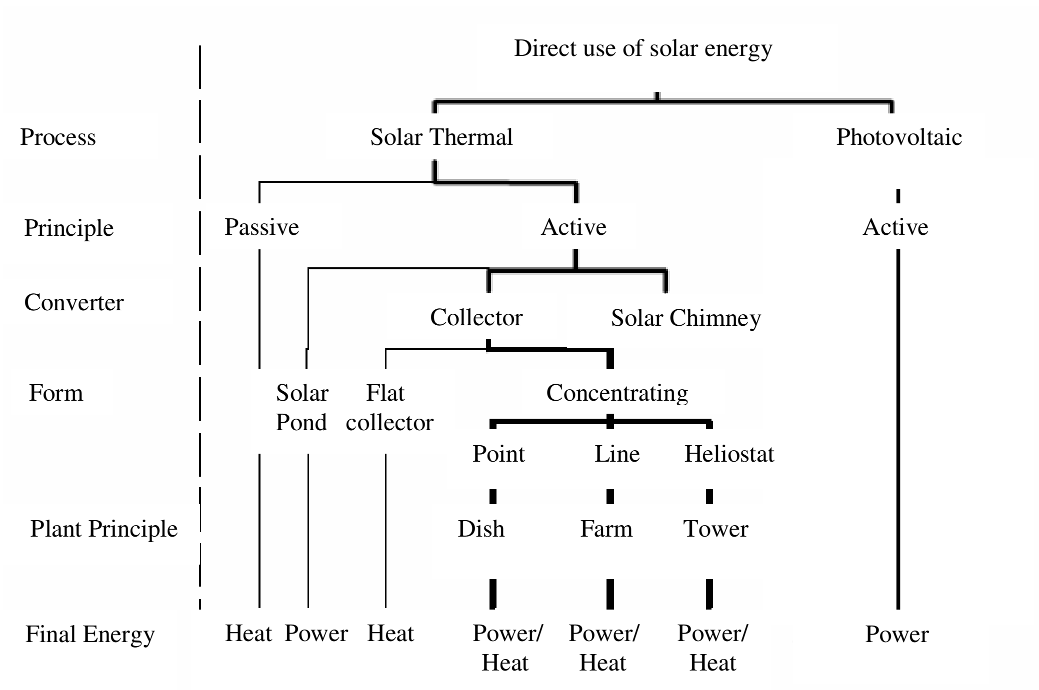

Fig. 2-2 How solar energy can be used /IER 2004/

The Concentration ratio is usually defined as C. It is the ratio between the optically active surface of the collector and the irradiated absorber's surface.

$$\mathbf{C = S_{coll} / S_{abs}}$$

The temperature in the absorber tube is strongly depending on C. Theoretically, on absorber's surface temperature of about 5700 °C should be reached, i.e. the temperature on the surface of the sun. Of course the practical achievable values are much lower. For example, in a Solar Dish, maximum temperature can reach 1600 °C, but only in rare cases /IER 2004/.

Concentrating systems can also be divided into three groups, depending on their way of tracking the sun: fixed, single-axis tracking, double-axis tracking.

Each of these approaches of concentration has a typical ratio of collected radiation intensity to incident solar radiation intensity, called "concentration ratio". **Fig. 2-3** summarizes the options discussed and lists typical concentration ratios, the resultant operating temperatures and the consequent thermodynamic limiting efficiency with which electricity could be produced. The limiting conversion efficiency arises from the second law of thermodynamics. The maximum efficiency for conversion of heat from a constant high temperature source is given by:

$$\textit{Maximum conversion efficiency} = \mathbf{1- T_{cold}/T_{hot}}$$

This is the "Carnot limit".

Technology	T [°C]	Concentration ratio	Tracking	Max Conv. Eff. (Carnot)
Flat plate collector	30 – 100	1	-	21 %
Evacuated tube collector	90 – 200	1	-	38 %
Solar pond	70 – 90	1	-	19 %
Solar chimney	20 – 80	1	-	17 %
Fresnel reflector technology	260 – 400	8 – 80	One-axis	56 %
Parabolic trough	260 – 400	8 – 80	One-axis	56 %
Heliostat field + Central receiver	500 – 800	600 – 1000	Two-axis	73 %
Dish concentrators	500 – 1200	800 - 8000	Two-axis	80 %

Fig. 2-3 Typical temperature and range of concentration ratio of the various solar thermal collector technologies /ANU 2005/

Solar pond, solar chimney, flat collector and evacuated tube collector have been mentioned to make a comparison possible, but in this work they will not be considered, since they are not systems of concentrated collectors.

2.2 Overview

The main concentrated solar power systems are the parabolic trough system, the parabolic dish system and the central tower system. After giving a first overview of the basic working principle of the different CSP systems, the single technologies will be analysed in detail: at first the chronology of their development, then their actual and future developments.

2.2.1 The Parabolic Trough

This is the form of a CSP system, where the solar collector field is composed of rows of trough shaped solar collector elements, usually mirrors, with an integral receiver tube. This concept is pictured below (**Fig 2-4**).

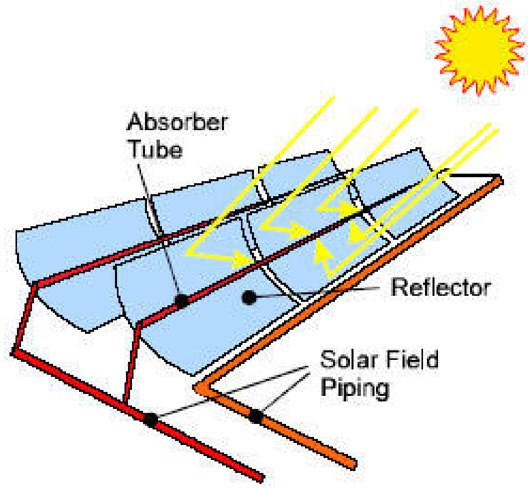

Fig. 2-4 Parabolic Trough /SolarPaces 2004/

The reflectors are parabolic in one dimension only and form a long parabolic shaped trough of up to 150m in length. The collectors are usually installed in rows and the total solar field is composed of several parallel rows. The collectors are connected to a single motor, controlled by a solar tracking control system, which ensures that the maximum amount of sunlight enters the concentrating system throughout the day.

The solar receiver is a black-coated, vacuum glass tube containing the heat transfer fluid, either oil or water. The concentrated sunlight heats the heat transfer fluid to temperatures of up to 400°C, which can be used to generate electricity using a turbine and an electrical generator.

Another option under investigation is the approximation of the parabolic troughs by segmented mirrors according to the principle of Fresnel.

2.2.2 The Central Tower System

As we can see in the figure **Fig. 2-5**, the central tower system is somewhat different as the solar collector field is composed of several hundred individual, large sun tracking flat plane mirrors, called heliostats. These heliostats track the path of the sun throughout the day and focus the rays on the solar receiver. The solar receiver can be an area of a few metres square which is located on the tower at a height of between 50 to 100 m according to the level of concentrated radiation to be collected.

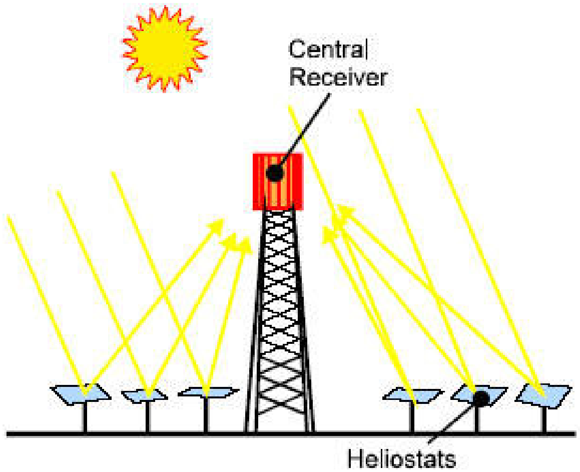

Fig. 2-5 Central tower system /SolarPaces 2004/

In these systems, a working fluid, either air or molten salt are pumped through the receiver where it is heated up to 550°C. The heated fluid can then be used to generate steam to produce electricity. Grid connection does not pose technical problems for CSP because in CSP plants the electricity generation utilises standard components from the power industries.

2.2.3 The Parabolic Dish

A parabolic dish system, or solar dish, as they are sometimes known, is composed of a single structure supporting a parabolic dish covered with mirrors that reflect light on a solar receiver located at the focal point of the dish, as shown in figure **Fig. 2-6**. On average, the dishes are between 8 and 10 m in diameter, but in some cases they can be much larger, for example, the world's largest is the 'Big Dish' in Australia which has an aperture of 400 m^2. The Big Dish has 54 triangular mirror elements attached to the dish-frame and produces steam at 500 °C, which feeds a steam engine driven generator connected to the Canberra grid.

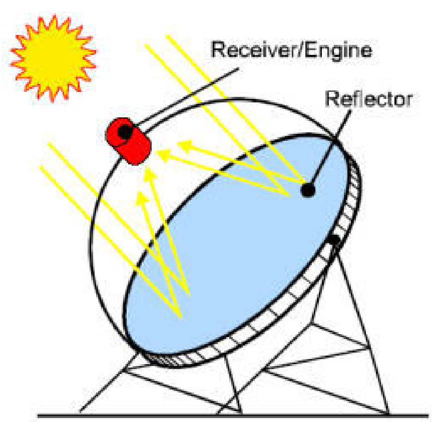

Fig. 2-6 Parabolic Dish /SolarPaces, 2004/

Solar dishes are being developed mainly for electricity generation and, therefore, the solar receiver is combined with the energy conversion element which is usually a thermal engine, such as a Stirling engine or a Brayton cycle engine. Parabolic dish systems are the most efficient of all solar technologies, with peak efficiencies up to 29 %, compared to around 20 % for other solar thermal technologies.

2.2.4 Applications

Solar thermal power is one of the most promising way to provide renewable energy, giving the fact that it can compete in the middle/long term with conventional power plants. As a result of international cooperation and government grants, many demonstration projects have been carried out or are still in progress, allowing an electricity generation cost for the near-term between 0,14 and 0,19 €$_{2005}$/kWh /Ferrer 2005/. Some examples are listed below (**Fig. 2-7**):

NAME OF THE FACILITY	Location	Technology	Net electric power	Maturity	State
SEGS	USA	trough	354 MW_{el}	Commercial	Completed
Andasol	Spain	trough	50 MW_{el}	Commercial	Under construction
Inditep	Spain	trough	4,7 MW_{el}	Pilot plant	In progress
Solar Two	USA	tower	10 MW_{el}	Pilot plant	Completed
CESA 1-PHOEBUS	Spain	tower	14,7 MW_{el}	Pilot plant	Completed
Weizmann (Israel)	Israel	tower	0.5 MW_{el}	Pilot plant	In progress
Eurodish	Spain	Dish/stirling	10 kW_{el}	Pre-commercial	Completed

Fig. 2-7 Examples of existing CSP plants /Ferrer 2005/.

There are also many project which have been planned in different countries of the sun-belt region of the world (**Fig. 2-8**):

COUNTRY	CAPACITY [MW_{el}] (2010)
Algeria	130
Australia	100
Brazil	100
Egypt	130
Greece	50
India	130
Iran	130
Israel	200
Italy	100
Jordan	130
Mexico	300
Morocco	150
Namibia	100
South Africa	100
Spain	200
United States	200
Total	**2.250**

Fig. 2-8 Planned CSP projects /Kearney 2004/

However, concentrated solar power systems can also be used for a wide range of applications depending upon the energy conversion utilised, also different form electricity. The parabolic trough collector is the best solution for applications in the low temperature ranges such as detoxification, liquid waste recycling and water-heating. All three systems are suitable for the mid temperature range applications, and the central tower is the most suitable system for high-temperature applications because temperatures of more than 1.000 °C can be easily sustained.

Where the technology is targeted at medium-to large scale production of electricity and/or heat, the intermittent nature of production and the high capital investment cost are disadvantages when compared to current sources of energy such as natural gas.

However, the diversity of application, ease of grid connection and low CO_2 emissions are significant advantages and the technology is currently being considered by power development companies as a means to complement existing power generation installations /European Research 2004/.

2.3 The Parabolic Trough

As pointed in the previous paragraph, Parabolic Trough power plants use rows of cilindric parabolic mirrors which focus the sunlight on a line. It will now explained which are the main components of this type of plant, the chronology of his development, together with its actual and future developments.

2.3.1 Components

Parabolic trough plants use a single-axis solar tracking system. On the surface of the receiver, a black-coated vacuum glass tube, the radiation is converted into heat and transported to the plant with a fluid that can be oil or water. Because of their top-view this kind of solar plant is also called Solar Farm.

The most important component of a Parabolic Through is the solar collector. Three different generations of collectors have been used in the only one existing power plant by the Californian company Luz Solar: LS-1 (Luz Solar-1), LS-2, LS-3, totally 2,3 Millions of square meters.

LS-4 (**Fig. 2-9, Fig. 2-10**) is the latest version of these collectors. All of them have been produced by the German company Pilkington Solar, formerly Flagsol GmbH. A relevant share of other key-components, for example the glass tubes, the structure-tubes and the hydraulic gears have been also produced and delivered by German companies.

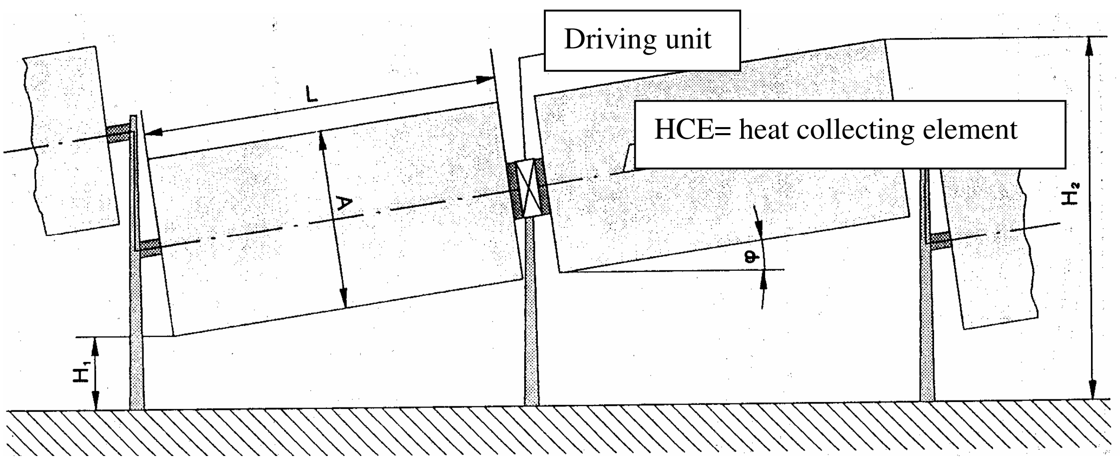

Fig. 2-9 Parabolic trough: LS-4 collector's front view /Ehrenberg 1997/

L = self-supporting lenght
A = aperture wideness
D = mirror's depth
F = focal distance
θ = side-angle
H_2 = highest point
H_1 = lowest point
φ = inclination
Y = f(x) =eq. of parabola

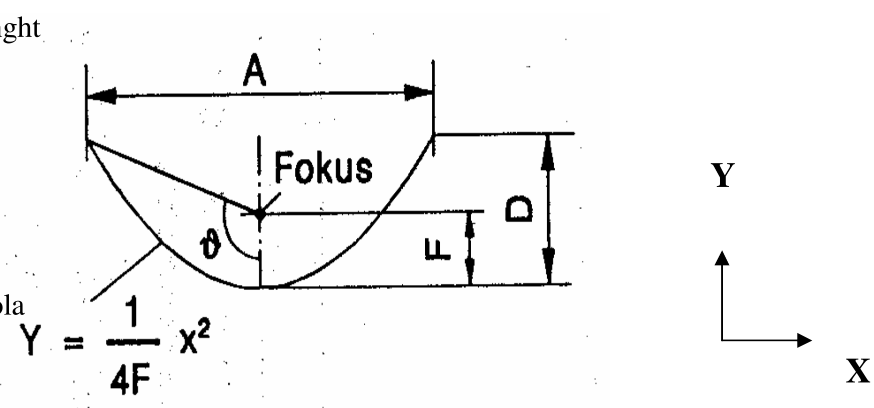

Fig. 2-10 LS-4 collector: heat collecting element (HCE) /Ehrenberg 1997/

The LS-4, 2,4 m^2 parabolic mirrors consist of a glass layer, covered on the back side by a silver layer. The reflective silver layer is protected against oxidation and climatic agents by epoxidic-resin layers and at its borders by sealings. The silver layers and the protecting layers are designed to last for 30 years, and after 20 years of life none of them show any sign of deterioration. Ceramic components with screws on their back-side are used to fix the layers /Ehrenberg1997/.

The mirrors have a reflection degree of 94 %, they concentrate 82 times the sunlight on the absorbing tube, which is made of steal and is covered by either a black Chromdioxid layer or a high selective metallic oxid-ceramic layer (absorption degree 97 %). To reduce the warm losses the absorbing tube is covered by a glass tube with a transmission degree of 95 %. The tubes are connected together with a flexible metallic sealing. Vacuum is produced in the space between the two tubes. It is otherwise filled with Xenon.

The main sun-tracking system is composed of a processor and a deviation gauge, while the sharp positioning is carried out by two photocells which measure radiation differences, allowing an electro-hydraulic actuator to orientate the collector with a precision of 0,05 degrees.

Conventional solar electric generating system (SEGS) plants use synthetic oil as heat transfer medium. It is stable and allows operation-temperatures of about 400 °C. The scheme of a Californian SEGS plant is pictured below (**Fig. 2-11**). It can be see that among the other components an oil-heater is also necessary.

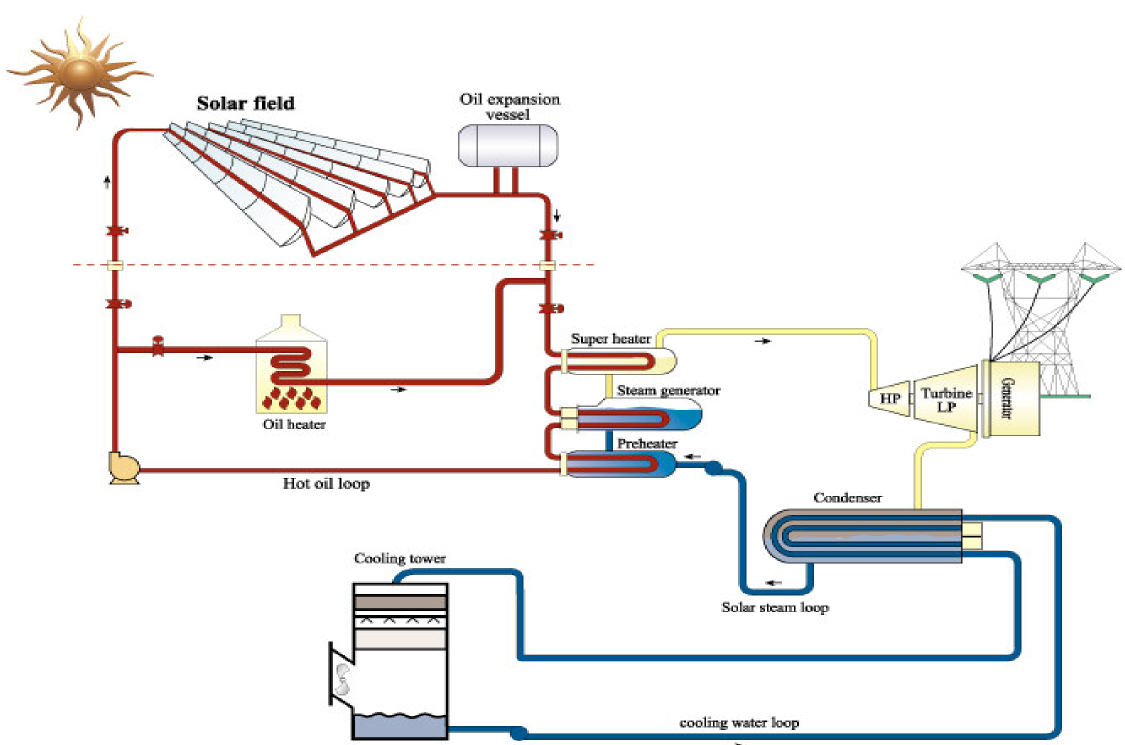

Fig. 2-11 SEGS power plant /SOLEL 2005/

Actual projects have accomplished the tasks of reducing costs and improving operating performance by developing and testing collectors using water as heat transfer medium through Direct Steam Generation (DSG).

The collectors LS-1 and LS-2 are built and optically adjusted “on site”, requiring therefore a huge amount of time. On the contrary the collector LS-3 is completely built in a laser-calibrated montage-bed and can be adjusted, divided into segments and transported; in the end it is assembled on the structure. On the back-side a rod-structure assures the necessary stability.

Compared with its previous version (LS-1 and LS-2), the LS-3 collector improves the optical efficiency to 80 % and the mirror wideness by 15 %, while the doubled mirror surface reduces the number of the actuators and control systems by 50 %, therefore reducing the specific costs by 30 % /C. Ehrenberg 1997/.

2.3.2 Chronology of development

The following summary refers to /Ehrenberg 1997/, /European Research 2004/ and /Eck 2005/ as sources:

The construction of SEGS plants is almost similar for all the different types of plants. The conventional steam cycle, with steam generator, turbine, heat exchangers, pumps, condenser, is situated in the middle of the almost square solar field. The heat transfer medium is pumped out from the plant core end divided into the pipeline net. For a 80 MW_{el} plant the total length of the pipes is around 100 km, 85 of them are absorbing tubes.

The Californian company LUZ has built the world’s largest solar energy generating system (SEGS I-IX), nine plants totalling 354 MW_{el}, on a pure commercial basis. The plant is situated in Kramer Junction, California (**Fig. 2-12**).

Fig. 2-12 SEGS plant in Kramer Junction, California /SOLEL 2005/

SEGS I is the only system with a storage capacity. Fossil fuel is needed for overheating, which means that the plant can operate only with enough solar irradiation and always with the help of natural gas. In order to reduce costs SEGS II-IX don't have storage capacity anymore.

In SEGS II a steam generator was added to the steam over-heater, allowing the plant to operate without any sunlight at all.

From SEGS III on, due to the increase of oil temperature, solar overheating was also possible. That means that SEGS III-VII could be operated in three different modes: solar-only, fossil-only and hybrid. This produced an improvement of performances, due to the reduced influence of fluctuating irradiation.

With the latest plants SEGS VIII-IX the steam generator was substituted by four overheaters with natural gas as fuel. One of them is kept during solar-only mode in readiness by keeping oil streaming through it, allowing by lack of sun irradiation very fast reaction times.

No more than 25 % of the electricity generated by SEGS plants can originate from natural gas. In the best years the share of fossil fuels was less than 5 %. In solar-only mode, a peak efficiency of 24 % has been reached, with annual net efficiency running at between 14 and 18 %. The thermal solar field efficiency in best days reached 58 %. An example of efficiencies measured on one of such best days is pictured in **Fig. 2-13.**

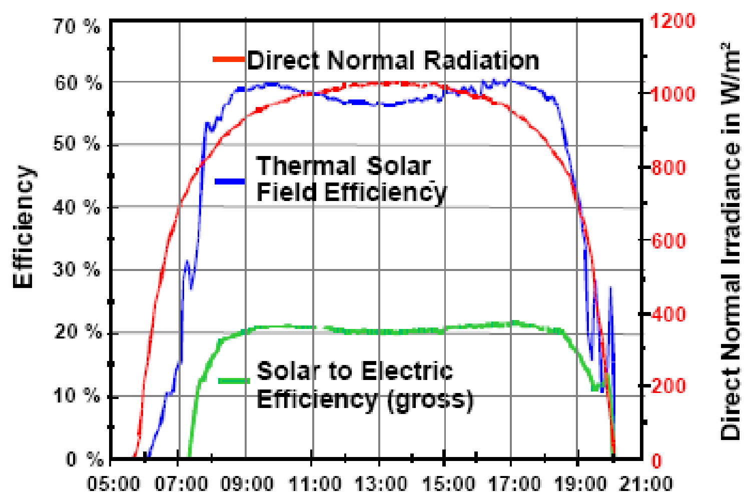

Fig. 2-13 Solar efficiencies measured at SEGS VI on July 1997 by KJC Company /Geyer 2000/

An annual capacity factor (the fraction of the year when the power is delivered in solar-only mode) of 24 % was proven. Fossil-only mode, like also conventional plant, has an efficiency between 34 % and 37 %. Concerning global efficiency, reflection-efficiency is very important, about 94 % in SEGS plants /Ehrenberg 1997/.

Since 1992 SOLEL has taken over the SEGS plants in California. Since then a series of research is undergoing, together with European and American partners, in order to develop the new LS-4 generation of solar collectors. We will follow these developments referring particularly to the publication /European Research 2004/ as source.

The main target of this development was the achievement of direct steam generation in the receivers. For this reason, with financial help from the European Union, a test facility named DISS (Direct Solar Steam Generation) has been built at the Plataforma Solar de Almeria (PSA) in Spain.

The technical challenges were to prove the feasibility of a stable two-phase flow operation mode using water, to gain information on O&M costs and procedures, to test the three basic steam operating modes (once-through, recirculation and injection) at three different operating pressures, and to identify further technology improvements. There was initial scepticism, especially at the time it was felt that it would not be possible to control the two-phase flow in horizontal evaporator tubes /Eck 2005/.

The main problem is that the trough's sides frequently dry up which leads to overheating. Due to temporal variation of solar irradiation (clouds) local differences in the solar field and even in a single absorbing line are possible, causing important problems of regulation and operation.

The approach was to test sequentially each step of the process. First, a single row of 11 solar collectors, capable of producing 300kW, was built with water as the heat transfer fluid within a test loop to extract steam. The row was divided into water evaporation and superheated steam sections. In the first section, the water is evaporated through nine solar collectors. In the second section of three collectors, superheated steam, i.e. steam at temperature above 400 °C, is produced.

Secondly, the three different operation modes (once-through, re-circulation and injection), and pressures were tested. In the once-through mode, whose scheme is pictured in figure **Fig. 2-14**, water goes once through both sections achieving a linear increase of the specific enthalpy of the fluid.

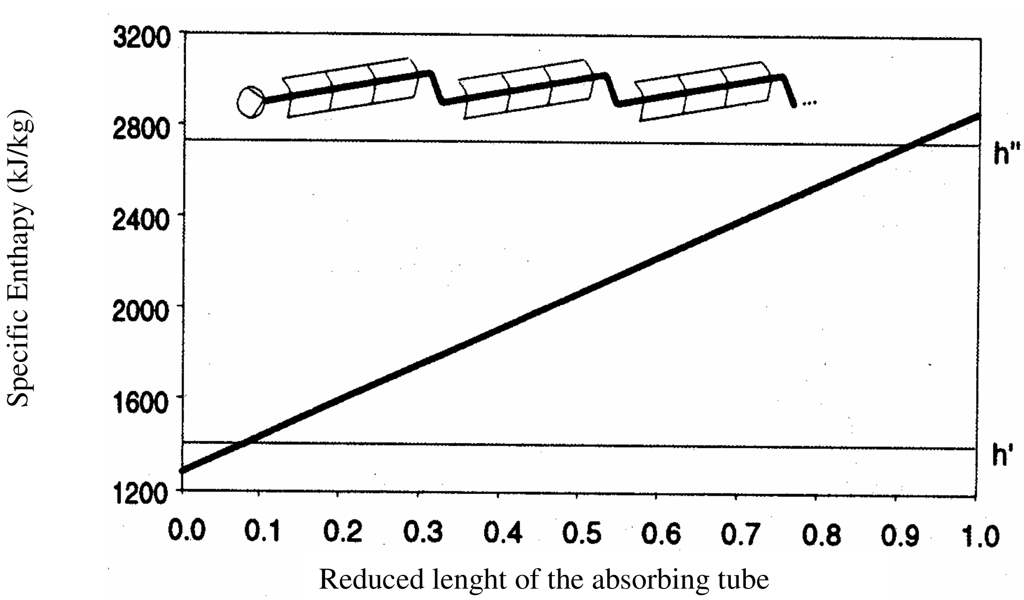

Fig. 2-14 Scheme of once-trough concept for DSG /Ehrenberg 1997/

In the re-circulation mode, a given amount of water is taken after the first section and re-injected at the beginning of the loop. In the injection mode, a given amount of water is taken after the first section and re-injected at different points in the water evaporation part, with the aim of increasing the global efficiency. This concept is pictured below (**Fig. 2-15**):

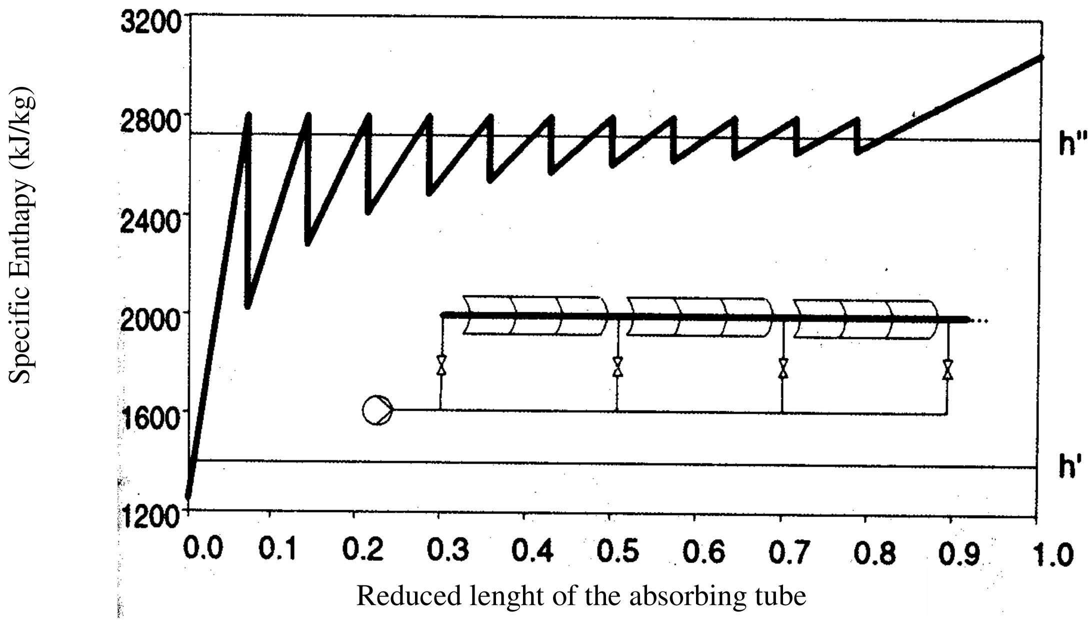

Fig. 2-15 Scheme of injection concept for DSG /Ehrenberg 1997/

Very soon it became clear that the recirculation concept is considerably superior to the others, especially with regard to its operational reliability and control behaviour.

In the case of the recirculation concept, the water mass flow at the entry to the collector line can be set as desired, thus an annular flow can be deliberately created, which always ensures sufficient cooling for the absorber tube. In addition, there is a clearly defined end of the evaporator region, so that unacceptably high temperature fluctuations in the absorber tubes as a consequence of a travelling evaporation end point are prevented. The initial reservations about the possibility of controlling the two-phase flow arising were thus dispelled /Eck 2005/.

As third task of the project, component improvements identified during manufacture and testing were evaluated. Finally, an economic assessment of the technology was performed which led to the development of a large-scale prototype plant.

These tasks were pursued in three different projects. The first one, "DIrect Solar Steam" (DISS), looked at the design of a real-size 300 kW test loop, the design of a control scheme for the three main operating modes (once-through, re-circulation and injection) and evaluated the potential of solar collectors for increased efficiency and reduced cost. In addition, an economic assessment of the technology was undertaken. The second project, "DIrect Solar Steam – Phase 2" (DISS-2), investigated the three operation modes, developed and implemented components following the improvements identified in the first project, and defined plant concepts for a DSG commercial power plant into either combined cycle plants or SEGS-like plants. The third project, "INtegration of DIrect solar steam Technology for Electricity Production" (INDITEP), continued the solar component improvements, developed new components able to operate at high temperatures and increased the length of the test loop to further study the re-circulation mode of operation.

The INDITEP project is the only one to be still in progress and it is expected to be completed at the end of 2005. The project is focusing on the decentralised generation market, with the development of a small size module, in the range 5 to 10 MW_{el}. Such a small size module would be cheaper and easier to implement, offering an opportunity for a larger number of installations, which should reduce risk and lead to economies of scale. Evident advantage of direct steam generation is the considerable cost reduction due to the exclusion of the oil-cycle. Moreover, by leakages, oil is a contaminating medium. The oil pumps will be excluded, therefore a reduction of plant's own power needs will occur (for a 80 MW_{el} plant, oil pumps require around 4 MW_{el}). Another important advantage is the reduction of freezing temperature from 20 °C to 0 °C, therefore reduction of the times in which a frost-protection is needed. Finally, the increase in steam temperature will increase the global efficiency.

The other two projects are EUROTROUGH I and II. They developed the LS-4 collector, which shows many improvements when compared with conventional LS-3 collectors. The challenges were to re-think parabolic trough collector design originating from the 1980s, and to build a cheaper and more efficient modern version. The project was divided into two stages, thus only after positive results the second step would have been taken.

The project focused on the design of the individual solar collector element to improve optical performance under wind loads and reduce costs during manufacture and assembly. In the first project, EUROTROUGH I, the basic LS-3 design was investigated in a wind tunnel and its behaviour simulated using advanced computer models. Then, a new concept (LS-4) was designed, built and tested. In the second project, EUROTROUGH II, the prototype was extended and then tested. In order to qualify the performance of the new design, comparisons needed to be made with the LS-3 parabolic trough collector design. This was done at the Plataforma Solar de Almerìa, where a collector assembly consisting of the new design parabolic trough elements was installed in parallel to the existing LS-3 parabolic trough elements.

Component's life of the future generation of collectors was improved. During the tests the new solar collector design, which in the meantime has been renamed "EUROTROUGH", showed stronger resistance to wind loads and improved operational performances than the traditional design, and reached a peak optical efficiency of 74 %. At 350 K above ambient, the global efficiency, radiation to thermal, was measured at 66 %. As part of the research projects, two case studies using the EUROTROUGH concept were analysed and compared, one in Spain and one in Mexico. In the Mexican case a Brayton cycle was capable of achieving thermal efficiency above 55 % /European Research 2004/.

This work is rounded off by intensive work on assessing the potential in southern Europe and northern Africa, in which high resolution satellite data are being analysed. According to these studies, the solar thermal electricity generation potential in Spain alone is sufficient to cover 50 % of the EU's electricity requirements /Eck 2005/.

2.3.3 Status Quo

The core of a parabolic trough is the receiver. A big optimizing effort has been undertaken in the past three years and further development is to be supported. Concerning conventional receivers, i.e. the ones deployed in Kramer Junction, with oil as transfer-medium, the research, development and planning activities were coordinated by Schott Rohrglas in Mitterteich. External institution like Deutsches Zentrum fuer Luft und Raumfahrt e.V. (DLR) were involved in the project, which produced many innovations and led to the design of the new receiver SCHOTT PTR70.

First of all, a new method of producing new high transparent, abrasion resistant anti-reflective coatings was developed. A transmission factor of 96 % is achieved, the abrasion resistance compared to the competing product has been enhanced by a factor of ten.

After that, a new fail-safe glass-to-metal seal was developed. Using a new type of glass with thermally adapted materials, a production method was developed by SCHOTT for the fusion of glass and metal. It was also possible to develop a cost effective coating process for the absorber. The solar absorptance is 95 %, the thermal emittance at 400 °C is 14 %. Finally, thanks to a special arrangement of bellows and seals, it was possible to minimize the heat losses, which led to a two-per-cent improvement in efficiency.

The federal Ministry for the Environment Nature Conservation and Reactor Safety has subsidised the project. Further development, together with market introduction, is now to be supported in a project named PARFOR, which runs until 2006 /Benz 2005/.

In the field of DSG, super-steam generation at 450 °C was successfully demonstrated by the INDITEP project under real solar conditions in the three operation modes. The tests showed that the re-circulation mode was the easiest to operate. The test-loop was operated for more than 3.600 hours over 37 months, averaging approximately 1.200 hours per year. A commercial installation is expected to average 2.500 hours per year. Operational experience has reduced start-up time from 1:45 hours to around 1 hour. Improvements have also been made on the sun-tracking controller, on the mirrors, on the solar receiver coatings and, in addiction, a secondary stage concentrator was tested.

In conclusion, half a parabolic solar collector assembly, 75 m section, was completed using the EUROTROUGH design, and was tested under real sunshine conditions for one year. This collector showed that 1.300 kWh thermal per year at a site with 2.300 kWh/m^2 annual direct radiation giving a performance of 60 % annual thermal collection efficiency can be achieved.

Other improvements are: doubled mirror wideness and increased side-angles, which raised the optical concentration and collector's inclination by 8° on the horizontal, therefore reduction of the Cosine losses. These are important losses due to the single-axis tracking, especially for plants situated at high latitudes. Moreover, absorbing tube cooling by two-phases flow (water-steam) is easier to control in such inclined collectors /European Research 2004/.

2.3.4 Future Developments

A big issue nowadays is thermal storage: in this field DLR and other industrial partners are working on a further improvement in the materials and design in a current project named WANDA (2004-2006). The objective is to identify the optimum means of integrating a storage system into the solar power plant, the utilisation factor of a storage system will be increased by means of an adapted, modular method of charging and discharging the storage blocks. This will create the basis for subsequent commercial implementation /Tamme 2005/.

An obvious solution for the problem of thermal storage in parabolic trough is to combine the storage of sensible heat and the use of latent heat. It is in particular the high energy demand of evaporation at a constant temperature which makes the use of latent-heat storage systems attractive. In the DISTOR project (2004-2007), which is being sponsored by the EU, three concepts are being investigated on a laboratory scale:

- Solid storage material system, where tubes are embedded in the phase change material. This requires a composite material with thermal conductivity, which is to be achieved by the micro-encapsulation of the phase change material in a matrix with very good thermal conductivity (**Fig. 2-16**).

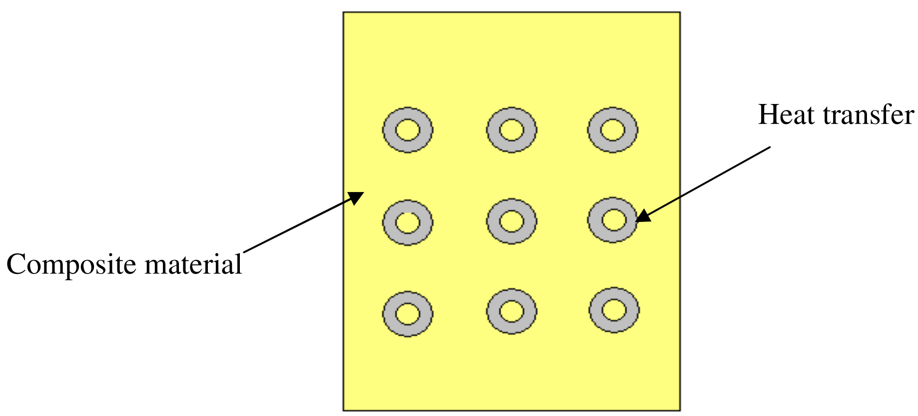

Fig. 2-16 Pipes embedded in the phase change material according to /Tamme 2005/

- The phase change storage material is encapsulated in thin-walled containers and placed directly in the pressure vessel holding water or steam. In this way, large heat-transfer surfaces and a very effective heat transfer can be obtained (**Fig. 2-17**).

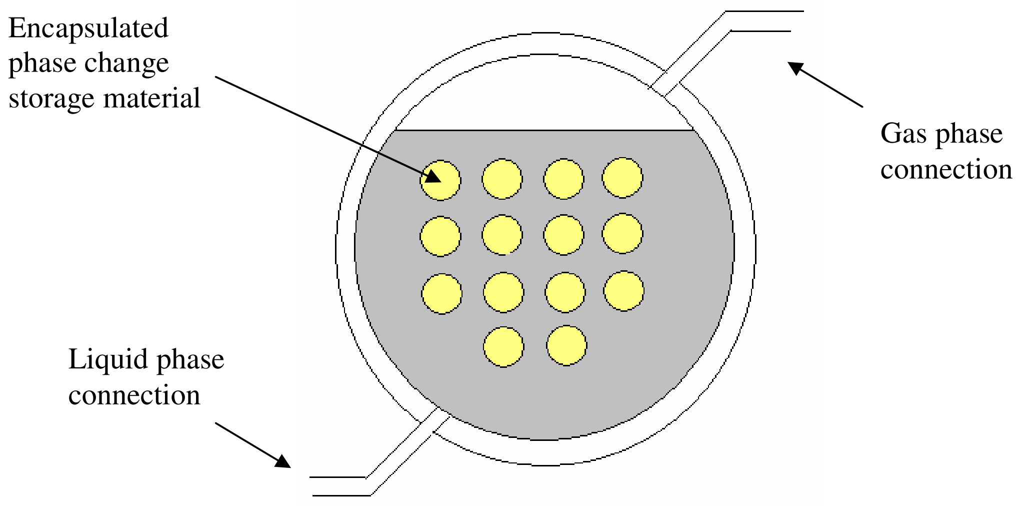

Fig. 2-17 Encapsulated phase change storage material in the pressure vessel according to /Tamme 2005/

- The energy is transferred between the steam and the storage medium via an auxiliary medium

The most successful system will be subjected to a trial on a 100 kW scale under solar boundary conditions. The first simulations have shown that, by improving the integration and operation of the storage system within the collector field and power station block, it's possible to increase the storage capacity significantly /Tamme 2005/.

Another interesting option for future developments is the approximation of the parabolic troughs by segmented mirrors according to the principle of Fresnel. The Belgian company Solarmundo, showing interest in this effective concept, operates a 2.500 m² prototype in Liège, Belgium. A scheme is shown below (**Fig. 2-18**):

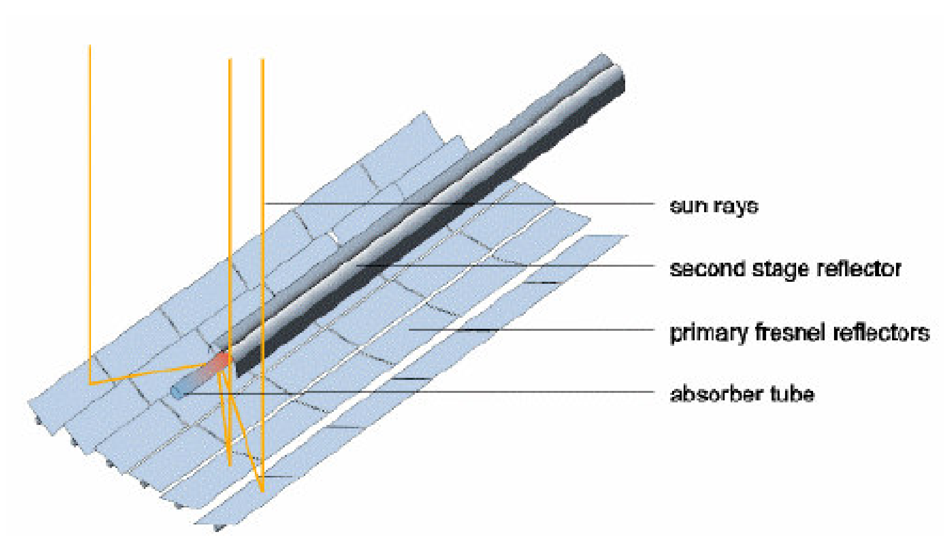

Fig. 2-18 Solarmundo Fresnel Collector /SolarPaces 2005/

The mirrors themselves, each having a width of 0,5 m, are not completely flat but have a very small curvature, which is achieved by mechanical bending. The collector consists of 48 rows of mirrors, which leads to a total collector width of 24 m. The second stage concentrator not only enlarges the target for the Fresnel reflectors but additionally insulates the selectively coated absorber tube.

The main advantages of a Fresnel collector, compared to trough collectors, are of course the much lower cost of the planar mirrors, the simple tracking system and the fact that, due to the planarity of the reflector, wind loads are substantially reduced. Moreover, there isn't need of heat exchangers (due to direct steam generation), vacuum technology and metal glass sealing anymore.

These advantages should lead to a cost reduction of about 50 % for the solar field compared to parabolic trough. 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.

Compared to the Solar trough technology there is an additional application for Fresnel solar collectors, which at present is not evaluated systematically but might show future benefits: a controlled greenhouse can be implemented in the space below the mirrors. By using the diffuse light and the light reflected on the back of the mirrors (~300 W/m²), one can produce the ideal circumstances for the growth of shadow plants even in arid climate zones /SolarPaces 2005/.

As for the DSG in parabolic trough, a big issue for the compact linear Fresnel reflector is to assure a steady state steam-circuit. A model has been developed by the university of New South Wales, Australia and tested in a Compact Linear Fresnel Reflector (CLFR) in a prototype at the Liddell power station in the Hunter Valley, NSW, Australia.

The reflector differs from the Solarmundo concept since it is 'compact': when a field of parallel mirrors has more than one absorber line, alternate mirrors in the centre of the mirror field between the absorber lines point in alternating directions in such a way as to reduce shading between adjacent mirror lines, thereby allowing denser packing of mirrors. This is shown in figure **Fig. 2-19**:

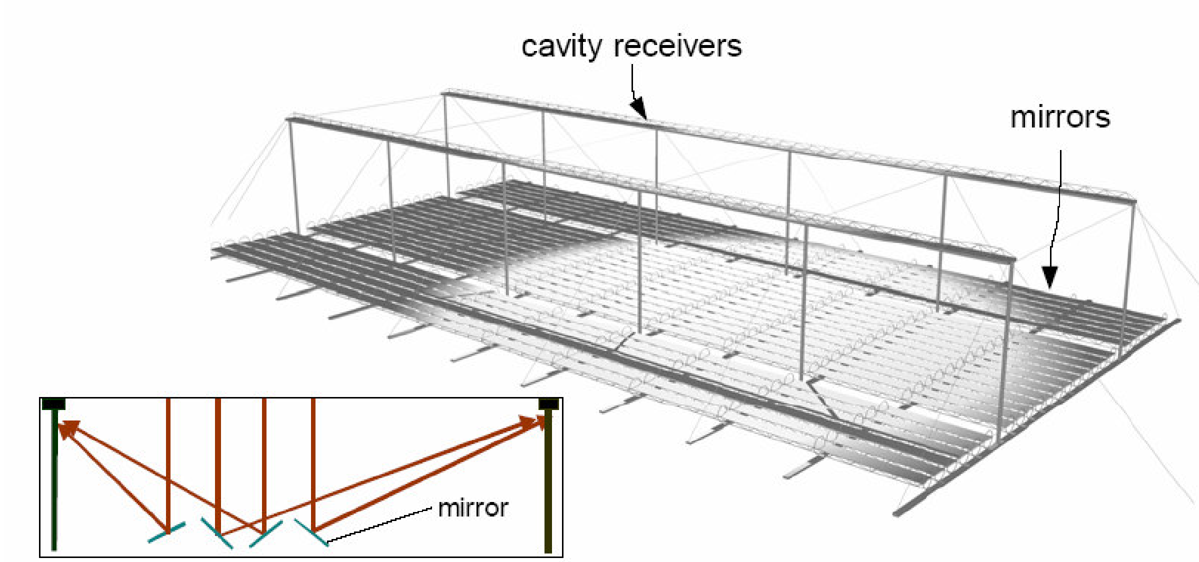

Fig. 2-19 CLFR system. In the focus the denser packing of mirrors made possible by pointing alternate mirrors at different absorbers can be seen /Pye et al. 2004/

The prototype constructed is the first stage of a three-stage process that will eventually equip the Liddell power station with a large array giving approximately 100 MW_{th} of solar energy collection, which will be used to provide final-stage boiler feed water heating, corresponding to an electrical generation of approximately 35 MW_{el} /Pye et al. 2004/.

Concerning future construction of parabolic trough plants, in Europe a 100 MW_{el} plant has been planned in Guadix, East-Andalusia. The two parabolic trough plants, named Andasol I and II, 50 MW_{el} each, will be built by a Spanish-German group. The first one should be connected to the net at the end of 2007. Andasol has a 7 hours storage capacity, which allows the plant to operate 3.800 hours per year /Ehrenberg 1997/.

Concerning the European projects on the PSA, the INDITEP project is the only one still in progress. Updated analysis showed that an increase in the steam temperature to 550 °C would increase the global efficiency by a further 4 %. Until now, no problems at all occurred, because of the flexible structure of the PSA test facility, which allows new simulation (sometimes performed at the DLR facility in Stuttgart), to be suddenly confirmed by real-time sunshine tests.

2.4 Central tower system

As for the parabolic through, this paragraph will describe the main components of the solar tower, then the chronology of its development, its actual and future perspectives.

2.4.1 Components

The following summary is based on /Ehrenberg 1997/ as source.

The principal element of the solar tower is the heliostat. With 30 - 50 % of the total costs, the heliostats field is the most expensive part of the solar tower plant. A conventional heliostat is composed of many single mirror facets, which can be put together on a steel structure and are oriented on a focal point. The mirror surface can be turned on the horizontal and vertical axis. A central processor drives each one of the single heliostats, thus the whole radiation is focused on the receiver. This process takes place with such accuracy that a high concentration factor is achieved.

Actual heliostats are made of thin metallic membranes or plastic foils. These membranes or foils are tightened on a metallic frame and brought to paraboloidic form within a low-pressure process. Compared to conventional heliostats, made up of glass and steal, the irradiation accuracy (i.e. the projection on the focal point) is improved and at the same time the mirrors are cheaper. Disadvantage is the less resistance to wind and sand erosion or the frequent cleaning processes.

The heliostats alignment at the bottom of the tower depends on the receiver type. An external-receiver, which can absorb light on the total length of his outer boundary, allows a circular disposition of the heliostats all around the tower. On the contrary, if the tower has a plain surface receiver or an opening on this surface, then the heliostats will be aligned on a particular field sector. When compared with parabolic troughs, it's easy to find out that central tower systems require more surface, since a certain distance must be kept between the single heliostats in order to prevent them from shadowing each other.

The only features that permit to distinguish between different tower systems are essentially two: the receiver type and the heat transfer medium. With regard to transfer mediums, since now water/water-steam, salt melts, liquid sodium and air have been tested. A fifth medium, a mixture of solid particles and gas for direct radiation absorption, is nowadays undergoing lab tests.

Four different types of receivers have been tested at the top of a solar tower:

- Cavity receiver
- External receiver
- Volumetric receiver
- Direct-absorption receiver

In a cavity receiver, which is a chamber-tube receiver, the heat transfer medium flows into the chamber inner walls, inside tubes which are bent into spirals and connected in parallel. The opening has a little surface which can be closed in case of temporary absence of light, in order to slow down outward heat transfer and cooling of the heat transfer medium. They are cheap to produce and are suitable for temperatures up to 600 °C. A second type of receiver is the external-receiver, which is made up of heat-transfer panels, i.e. panels composed by many heat-transfer tubes. A big problem of such receivers is the freezing of the medium, which occurs between 110 °C and 220 °C for salt melts and at 95 °C for sodium. In case of extended absence of light the tubes therefore must be completely evacuated /Ehrenberg 1997/.

At higher temperatures, volumetric receivers are installed. In a volumetric receiver the heat transfer surface is made up of special, high-temperature resistant fibres or wires, either metallic or ceramic, ceramic foam or honeycomb structure. This 3D structure absorbs the radiation, then air is aspirated into it, thus transferring heat to the steam generator. A quartz window is located behind the exit aperture of the concentrator. This window, which is inserted in a pressure vessel, enables the receiver to be operated at pressure of up to 15 bar. The absorber consists of several layers of porous material, which absorbs the radiation in the depth of the absorber and converts it into heat. For temperatures up to 800 °C, wire meshing of high-temperature resistant metal wire is used, while at higher temperatures the absorber consists of high-porosity ceramic foams /Buck 2005/.

Advantages of the volumetric air-receiver (**Fig. 2-20**) are the uniform distribution of temperature both in axial and radial direction and that the mean temperature of the receiver's frontal surface, in contrast to the other receiver types, is always lower than the maximum medium's temperature. Outward heat transfer, which depends on the surface temperature, is therefore decreased.

Finally, in direct-absorption receivers the heat transfer is carried out by thin fluid films or by little particles which stream in an air-flow. Receivers of this type nowadays exist only as prototypes; they can achieve peak temperature of 2.000 °C and heat densities of 2.000 kW/m^2.

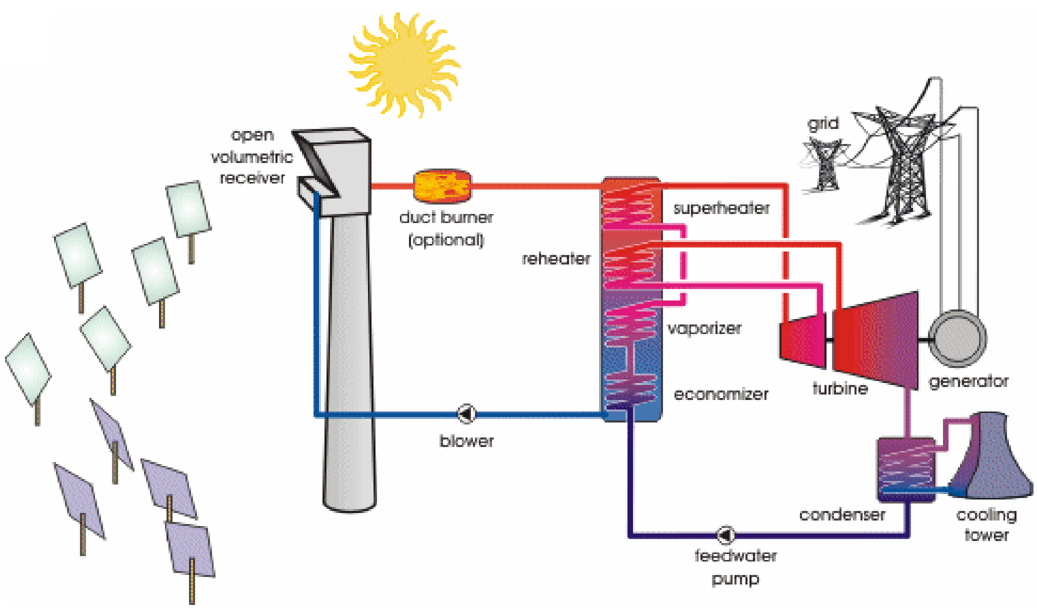

Fig. 2-20 Scheme of an open volumetric air receiver with steam turbine cycle /Earthscan 2003/

Each heat-transfer medium has its own thermo-physical properties, which still have to be deeper investigated. Moreover prices and availability of such fluids, together with their ecological and security aspects have to be estimated. Some other important operational issues don't have to be forgotten, like thermal inertness of heat transfer medium during transitory periods and own consumption for pumps, ventilators and electrical heating in case of medium's frosting. The results of this optimizing process were very different: while in the USA the plant SOLAR ONE has been built, with external receiver and water/steam loop, in Europe German companies have designed the PHOEBUS plant, which is intended for developing countries and operates with volumetric receiver and an air-loop /Ehrenberg 1997/.

2.4.2 Chronology of development

The following summary refers to /EDISON Technology solution 1999/ as source.

The first experiments, named “Solar central receiver” (SCR), “Solar Tower” or “Power Tower”, began in the 1970s in the USA. The successful results of such tests enabled the construction of eight plants worldwide, all of them between 0,5 and 10 MW_{el}. Most of them have been shut up after the project’s conclusion, others have been kept in operation as demonstration plants.

Because of his realistic operating experience, especially SOLAR ONE, a 10 MW_{el} plant built near Barstow, California, has to be mentioned. The plant opened in 1982, and during its six year operation successfully passed all testing and evaluation procedures. The 200-foot receiver is surrounded by a circular array of 1,818 sun-tracking heliostats, each about 7 meters on a side. During Solar One's operation, it delivered more than 37 million kWh to the utility grid. In 1988, the most successful year of SOLAR ONE, plant availability reached 95 % and during some days it operated 15 hours continuously.

Experience accumulated with SOLAR ONE led to construction of SOLAR TWO. Conversion to Solar Two required a new molten salt heat transfer system. This included the receiver, thermal storage system, salt piping, and steam generator. Molten salt power tower technology was pursued because the design decouples the solar collection from the electricity generation better than water or steam systems. In addition, the molten salt power tower approach incorporates a cost-effective energy storage system. This energy storage allows the solar electricity to be dispatched to the utility grid when the power is needed most, increasing the economic value of solar energy. A new master control system was also installed. The Solar Two plant demonstrated the use of molten salt both as a receiver and as an energy storage fluid for the first time in an operating solar-electric generation station.

Key outcomes of SOLAR TWO were the improvements in efficiency and dispatchability. In fact the receiver efficiency matched its design specification of 88 % efficiency in low-wind condition and matched modelled results in high winds. The efficiency of the thermal storage system also matched it design goal of 98 % efficiency. Concerning dispatchability, using its extremely efficient thermal storage system, Solar Two delivered electricity to the grid around the clock for 153 consecutive hours

Moreover, when compared with SOLAR ONE, the electricity required to run the plant was reduced by 27 percent, demonstrating that the plant routinely met its design goal. The plant also produced a record turbine output of 11.6 MW_{el} /EDISON Technology Solution 1999/.

The European PHOEBUS system is the only competitor of SOLAR TWO. On the PSA the PHOEBUS-TSA test system, with 2,5 MW_{th} volumetric air-receiver (700 °C) and a 1 MW_{th} storage, consisting of a fill of little ceramic spheres, has been successfully tested in 1993/94.

A summary of central tower power plants worldwide, together with their different storage capacities, is shown in the following **Fig. 2-21** :

	Eurelios (Italy)	Sunshine (Japan)	IEA-CRS (Spain)	Solar One (Usa)	Solar Two (USA)	CESA 1-PHOEBUS (Spain)	Themis (France)	MSEE (USA)	Weizmann (Israel)
Net electric power [MW_{el}]	1	1	0.5	10	10	1.2	2.5	0.75	0.5
Total reflect. Area [m^2]	6.260	12.912	3.655	71.095	81.344	11.880	10.740	7.845	3.500
Heat transf. fuid	Water/ steam	Water/ steam	Sodium	Water/ steam	Molten salt	Water/ steam	Molten salt	Molten Salt	Beam down
Storage capacity [MW_{el}]	0.06	3	1.0	28	107 MW_{th}	1	15	2.5	-
Storage medium	Eutectic salt	Steam Storage	Sodium	Oil	Salt	Salt	Salt	-	-
Periode of service	1980 - 1984	1981 - 1984	1981 - 1985	1982 - 1988	1996 - 1999	1993 - 1994	1983 - 1986	1984 - 1985	2001- in progress

Fig. 2-21 Summary of central tower demonstration power plants /ANU 2005/

Except the plants mentioned above and the one installed in Themis (France), the others didn't produce the expected results. They have been therefore shut down or converted in different test installations /ANU 2005/.

2.4.3 Status Quo

This summary is based on /European Research 2004/, /Buck 2005/.

In big commercial plants the two concepts of tubular salt-receiver (SOLAR TWO) and volumetric receiver (PHOEBUS) seem to be effective.

The main aim of the projects undertaken by the European Research was to design a cheaper and modular solar receiver based on ceramic volumetric absorber modules It uses air as heat transfer medium which could operate with an outlet air temperature of 750 °C and includes a large enough safety margin to allow safe operation in all weather conditions.

Using air as heat transfer medium leads to several advantages: air is an easy medium to work with; it is abundant, free and environmentally benign. The receiver design can be modular, simple and easy to manufacture which will lead to a reduction in costs (scaling-up). In fact inexpensive series production of the solar components is then possible even for medium-sized power station. The availability of spare parts and the latest state of the art can be in this way always assured. Moreover, with a modular structure, despite the high level of standardisation, the plant can be adapted individually to the necessary output and the conditions on the spot.

Thanks to air receiver technology, the steam process can be operated with the high steam parameters which are customary in conventional power station engineering. In this way, comparably high efficiency levels can be achieved.

The plant concept can be expanded by adding an additional furnace. This makes simple hybrid operation possible. Adding a gas turbine gives rise to a solar hybrid gas and steam power station, which can be used to supply even remote location in an inexpensive and environmentally compatible way. Moreover, the use of the hot gas storage unit enables the plant's energy production to be adapted to the demand curve, which avoids the constant fluctuations in production. Finally, the air receiver technology is also suitable for a number of chemical high-temperature processes, such as solar hydrogen synthesis /Buck 2005/.

In Europe, due to economical reasons, the first PHOEBUS plant has not been designed as a solar-only with thermal storage anymore. On the contrary it will be a fossil-fuel assisted hybrid plant. Heliostats field, receiver, air ducts and ventilators can therefore be smaller and cheaper, while almost constant operation prevents temperature cycles from reducing components' life. The plant is able to run either in solar-mode or 100 % fossil-mode. Direct steam generation for application in gas/steam combined cycles have been also investigated.

A big issue for these plants is to develop a heliostat which is able to match the PHOEBUS requirements and to reduce significantly the costs by light-constructions, in opposition to actual glass-metallic heliostats with pillars and central driving-system. A German experimental membrane-reflector (150 m^2) is undergoing tests on the PSA while similar concepts are developed in the USA /Ehrenberg 1997/.

To tackle the technical risks inherent in the PHOEBUS project, the consortium planned the work to run in two consecutive phases. In the first phase, the main design parameters and choice of materials were to be solved and tested. In the second phase, the modular aspect of the new receiver was developed and tested. In the first phase, ceramic materials were chosen as the receiver's material, in preference to a metallic mesh because ceramics have better resistance to high temperatures and to weathering.

All the components were to be qualified, assembled and tested as part of a new 200 kW_{th} receiver to be tested at the Small Solar Power System (SSPS) site of the PSA. The SSPS site consists of 93 heliostats with a total reflective surface of 3.655 m^2. In addition, material investigations on absorber material degradation were to be performed with the exposed elements, in order to estimate lifetime expectations.

From the results obtained during the first phase of the project, the second phase was designed to develop and test a larger receiver to provide the necessary intermediate step in the scale-up to a large scale application, to reduce technical and commercial risks. Given that current concentrated solar thermal central tower plants are at least 10MW_{el}, i.e. about 30 MW_{th}, a 3 MW_{th} receiver was chosen as a good intermediate step. The receiver was to be tested at the second site of the PSA, the "CESA" tower which has 300 heliostats representing a total reflecting area of 11880m^2. In parallel, a detailed optimisation analysis on solar power plant cycles was performed to fully exploit the expected benefits of this advanced receiver system /European Research 2004/.

In conclusion, we can say that research on the most important components and on the complete system concerning hybridisation is so advanced that technical and economical potential can be exactly defined and simulated. Confirmation of such results, however, can only take place after construction and operation of big solar-tower plants, for which the experience from a 30 MW_{el} prototype plant like PHOEBUS is absolutely necessary.

2.4.4 Future developments

The installation of beam-down optics at the Weizmann Institute's (WIS) solar power tower in Israel marks an exciting step forward for the development of a novel solar tower concept. Beam-down optics are part of a total solution aimed at increasing system annual efficiency, thus less heliostat area is required for a given power output. The placement of receivers and power block on the ground also simplifies operation and leads to considerable cost reduction.

This configuration, first proposed in the 1970s, was originally considered impractical but thanks to technological developments this assessment has changed. Given modern high-reflectivity surface technology and the application of non-imaging high concentration principles, this design approach is now seen as a promising concept for large-scale, high-performance solar applications.

The Weizmann Institute's solar tower, on which the optics is installed, is one of the five research solar towers existing in the world. Experiments at a megawatt scale can be performed in the tower at five levels, using highly concentrated solar energy. The new optical system installed on the tower is a 70 m^2 hyperboloidal reflector, with its upper focus coinciding with the heliostat field's aim point (**Fig. 2-22**, bottom). The reflector redirects the solar radiation from the heliostat field towards the lower focus of the hyperboloid, near ground level.

Fig. 2-22 Reflector in the Weizmann's Institute solar power tower /SolarPaces 2001/

Final concentration non-imaging devices and receivers are installed below the lower focal point. Magnification of the sun image by the hyperboloidal mirror is compensated by the ground secondary concentrator (**Fig. 2-23,** below) and overall a higher concentration is achieved.

The following paragraph will explain more about non-imaging devices, which is one of the biggest technological challenge in solar concentrated power systems.

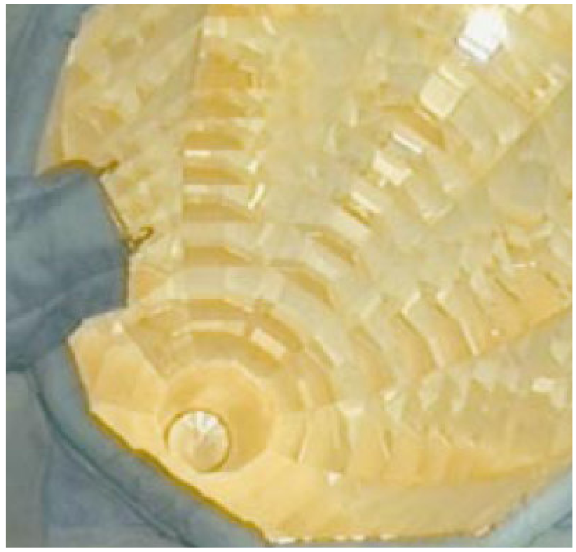

Fig. 2-23 Secondary concentrator (CPC) at the Weizmann's Institute solar power tower /SolarPaces 2001/

The novel optics are just one part of a solar combined-cycle electricity generation system under development, also incorporating high-performance air receivers and a solar-to-gas turbine interface /SolarPaces 2001/.

This interface is very useful in a hybrid support of natural gas fuel, where fuel is available. And in the future, it can be done by incorporating alternately high temperature phase-change energy storage, when conventional fuel is not readily available at the site. A 500 kW_{th} scale pilot facility, representing this technology, is undergoing final hot testing at the Weizmann Institute's Solar Tower Complex. The realization of the project follows a detailed technical and economic feasibility study completed in 1995 /Consolar 1997/.

On the European side, despite the success achieved, more development steps are still needed before the technology can be used on a large scale. The prospects of success are greater for the market introduction of small solar hybrid gas turbine systems, which achieve a high overall utilisation ratio by cogeneration. One example of such a system is a project concerning a solar-assisted energy supply system for a hospital that is under construction in Empoli in Italy. In this case DLR is playing a major role in designing and manufacturing the receivers for two small solar tower facilities. Each of the two plants is intended to generate 80 kW_{el}, and the waste heat will be used for air-conditioning and to heat water /Buck 2005/.

Another 10 MW_{el} power plant, with 981 heliostats and a 90m high tower, is to be designed, constructed and operated by the Spanish company Solùcar near Seville. The start of operation is planned for early 2006 /European Research 2004/.

However, the most ambitious project is perhaps SOLAR TRES, a 17 MW_{el} power plant which will be build by a Spanish-American consortium in the southern-eastern region of Spain. The exact location has not yet been individuated. As the name suggests, the plant is a natural consequence of the American SOLAR ONE and SOLAR TWO projects, since it's based on a salt-melt loop and will have a powerful thermal storage of 15 hours. The 2.750 heliostats will be deployed all around a 120 m high tower, allowing the production of 105 millions kWh per year. The construction is expected to last three years /SENER 2004/.

Non-Imaging Optics

The novel concentrator designs and optical elements used as secondary concentrator in the WIS Complex achieve performance which were thought to be impossible under the limitations of imaging optics. Tests have demonstrated solar concentrations of more than 84,000 times the ambient intensity of sunlight. Such ultra-high flux levels exceed those found at the surface of the sun.

The concentrator is a CPC (compound parabolic concentrator) optically coupled with a DTIRC (dielectric total internal reflection concentrator) /Winston 1986/.

A CPC is a Compound Parabolic Concentrator, a device developed by Winston at the University of Chicago. Its extremely efficient concentration of light makes it the only concentrating solar collector to be used on buildings.

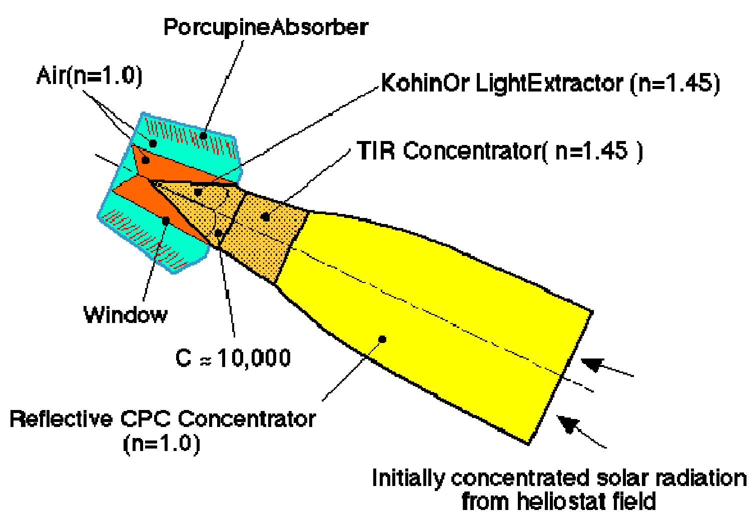

Fig. 2-24 Scheme of the secondary concentrator /Sun Day Symposium 1996/

The concentrator is pictured above (**Fig. 2-24**). With it a total output power of 860 W over a 4.6 mm diameter aperture has been measured. The output power is the highest ever for a ultra-high flux measurement.

The light is initially concentrated in the CPC section, then in the DTIRC section, which is made up of a TIR concentrator and a Light Extractor (**Fig. 2-25**). It is therefore guided with minimal losses into the receiver's annular aperture, and extracted in a pre-designed pattern in the receiver's absorption section. The light extraction from the high index of refraction medium into the receiver cavity, with minimal reflection losses, required a sophisticated optical design (gem-like shape).

The Light Extractor is a three-sided pyramid cut into a cylinder attached to the CPC exit. Light exits from the extractor very efficiently into air. This design allows unlimited scale concentrators to be built as optical coupling to a thermal electric generator is very simple.

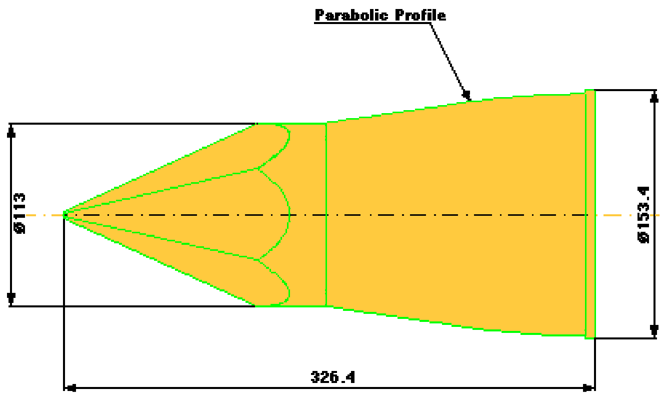

Fig. 2-25 The DTIRC section /Sun Day Symposium 1996/

Apart from the higher concentrations that can be achieved, this combined reflective/refractive design has other advantages over standard reflective-only CPC design. The most important one concerns cooling. For example, the extracted light has a precise distribution, allowing an efficient convective cooling. Moreover, the DTIR section, where the radiation is most intense, requires relatively little cooling, since it absorbs much less radiation than a conventional CPC /Sun Day Symposium 1996/.

2.5 Solar dish plants

The solar dish is a convenient solution for off-grid electricity supply. Despite its high initial investment costs, it shows very high efficiencies. Two ways of collecting the energy from the sun with a dish have proven successful, giving birth to two different technologies: the Dish/Stirling systems and the Solar Farm.

2.5.1 Components

The following summary refers to /Ehrenberg 1997/ as sources.

Direct solar radiation is collected by a two-axis rotating paraboloidal reflecting mirror (dish) into a focal point, where a receiver transforms the concentrating energy into heat. The next step, the transformation of heat into electrical energy, can happen in only two ways:

- In Dish-Stirling systems a Stirling motor is built together with a generator in the focal point. In this way mirror, receiver, motor and generator are rigidly connected and track as a whole the sun.
- A second option is to collect heat trough a proper medium flowing through many Dish-collectors, a concept similar to the solar farm. They are therefore called Dish-Farm plants. The steam generated is then used in a separate, conventional cycle to generate electricity. Unlike Dish-Stirling systems, they can support a heat storage.

The mirror's opening is always aligned with the sun. There are two ways of following the sun:

- Polar tracking: the rotations on both the axis are decoupled, so that the system in the course of the day turns only on one polar axis, parallel to the axis of the earth.
  Once a day the polar axis inclination is adjusted to the seasonal inclination of the sun.
- In the azimuthal tracking, two motors make the mirror follow the elevation's angle and the azimuthal's angle of the sun by continuous turning around a vertical and horizontal axis.

These options are shown in the picture below (**Fig. 2-26**):

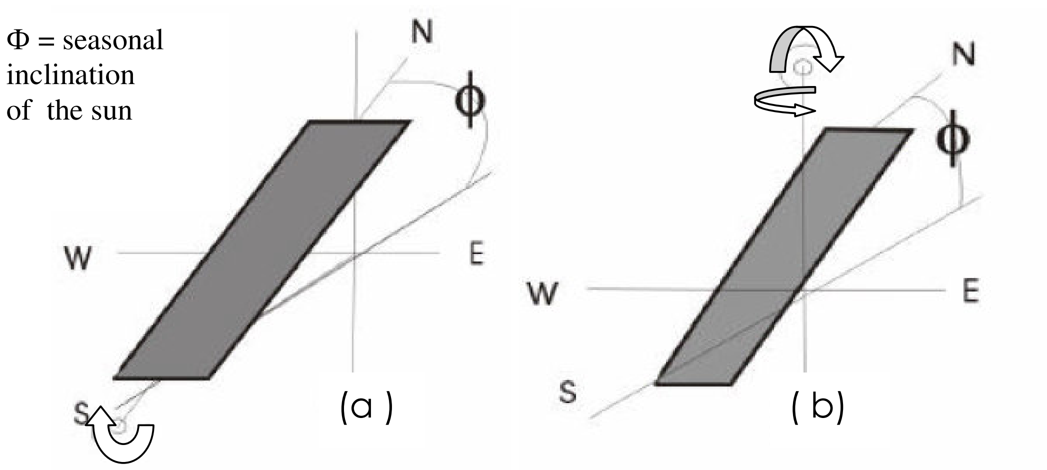

Fig. 2-26 a) Polar tracking; b) Azimuthal tracking /Universidad Politecnica Madrid 2005/

The position's control is performed by a processor only or might be assisted by sensors who measure the status of the sun. Today dishes have usually diameters ranging from 3 to 22,6 m. Like the heliostats of a solar tower, two kinds of construction have proven to be successful.

The first one is a facet-like construction, where a steel structure supports a series of glass segments or little foil paraboloids. This option requires a long work time and high investments because the segments are assembled one by one.

The second construction provides a correct, continuous collector's shaping which can be achieved by using hard, glass fiber reinforced foam or by hydraulic forming of thin, metal or plastic membranes (0,1-0,5 mm), afterwards stabilised with low-pressure processes. In this case very thin glass mirrors are glued on the membranes, allowing reflection. The facets don't need one-by-one arrangement anymore, since the steel skeleton provides already the necessary paraboloidal form. Plastic foils are usually covered with proper reflective layers.

Advantage of metal foils is that they contribute to the global stiffness enhancement of the structure, allowing therefore less material deployment than plastic foils /Ehrenberg 1997/.

2.5.2 Chronology of development

The following summary is based on /Ehrenberg 1997/ as source.

Target of researchers was the production of process-heat from 200 up to 400 °C to generate electricity in a separate plant's block. For this reason Dish-farms with more than 700 dishes have been set up and power plants of 5 MW_{el} have been operating for many years. However, after the successful achievements of SEGS plants, whose reflectors are easier and cheaper to produce, in the 1980s research work came almost to a complete stop and only in the 1990s could be taken up again.

It is in decentralised power production, with Dish-Stirling systems from 3 to 50 kW_{el} each, that already earliest tests showed the most encouraging results. The advantages of two-dimensional bending of concentrators and the high process-temperature achievable (more than 1.000 °C) led to very high efficiency.

Since the beginning research focused on the collector and on the Stirling engine, afterwards on its adaptation to the solar concentrator. Germany was very active in these fields: “Schleich, Bergermann und Partner engineering” took part in a German-Saudi Arabian project sponsored by the German Ministry for Research and Technology. The results were the solarisation in 1984 of a 75 kW_{el} Stirling engine, previously gas fuelled, and its testing in two concentrators (diameter 17 m) of 50 kW_{el} each.

The engine consists of 78 metal tubes and transfers the absorbed solar energy to the gas (helium or hydrogen) flowing through the tubes. The receiver is mounted between the two cylinders, which are arranged in a V-shape, and whose pistons transfer the mechanical energy resulting from the expansion of the gas directly to the generator via a crank mechanism. A water cooler at the compression cylinder cools the gas down again. A regenerator between the receiver and the cooler improves he efficiency of the cyclic process by alternately absorbing and releasing heat from the gas /Heller 2005/. This plant accumulated about 5000 hours of service.

A smaller version, a two cylinders, 160 cm^3 motor (**Fig. 2-27**), was solarised and tested within a German-American project in 1988, reaching 8 kW_{el}. The metal-foil concentrator, diameter 7,5 m, was also a new concept. Such an engine was chosen because 160 of them had already been constructed at that time, having accumulated therefore the highest number of operating hours ever. Together with a gas burner it has an output power between 10 and 15 kW_{el}, depending on the speed (from 1.500 to 3.600 rpm). The engine efficiency is about 30 – 32 % /Ehrenberg 1997/.

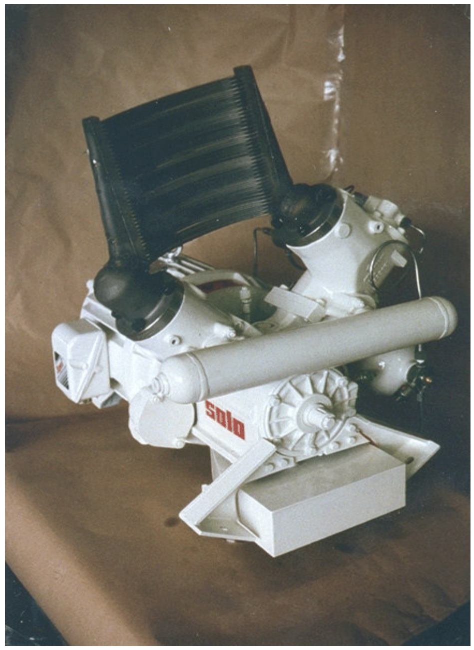

Fig. 2-27 SOLO V160 Stirling engine /Sandia National Laboratories/

German-American research teams have been very active in system's development and testing, in order to get know-how, increase reliance and life of components, process optimisation and reduction of operational costs.

For this purpose since 1992, within a project named DISTAL, three Dish/Stirling systems developed in Germany (7,5 m diameter, 9 kW_{el} power with 1.000 W/m^2 of radiation) have been tested. A big amount of data has been collected: characteristic curves, influence of atmospherical factors (wind, temperature, rain, etc.), operational and maintenance costs. Until 1997 about 27.000 hours of operation have been accumulated and plant's availability was more than 90 %. Afterwards, in order to increase efficiency, a bigger concentrator (8,5 m diameter, 56,7 m^2 surface) was tested. In this case, despite very little increase of manufacturing costs, the increased surface enabled more energy collection. Therefore annual power generation increased by 30 % /Heller 2005/.

2.5.3 Status Quo

In the following chapter two systems are examined: the Dish/Stirling and the Dish/Farm concepts. The Dish/Stirling will be examined first.

- Dish/Stirling systems

The following summary refers to /Ehrenberg1997/, /European Research, 2004/ as sources.

Consequence of the positive results of the DISTAL project was the decision to build at a suitable place in Europe a 1 MW_{el} plant made up of 100 modules of 10 kW each. In this way, scaling up should bring a further reduction of costs. Long term target was a 40 % reduction of totals costs and the installation of 1.000- 4.000 units a year. An important target is the hybridisation of the whole system using gas or oil as fuel. In fact the properties of Stirling engines, which are heated from outside, can be very useful in this case. The first concepts are based on a special heat exchanger which is exposed to sun on his upper side and can be fuel-heated on the opposite one. Such a system has the advantage of reducing significantly power generation's costs because of increased plant availability.

The increase of efficiency also shows a big potential: lab tests show that increasing actual operating temperature (700 °C) to 1.000 °C - 1.200 °C, for example by using ceramic materials, would result in a Stirling efficiency increase from actual values of 30 % to 40 - 50 % /Ehrenberg 1997/.

On the PSA, two important projects, EURODISH (**Fig. 2-28**) and HYPHIRE, have been completed.

In the first one, the main aim was to reassess the existing dish/Stirling concept to reduce cost. Four areas of dish/Stirling systems had to be investigated: the optical dish design, the supporting structure, the Stirling engine and the control system. The project aimed at optimising the dish/Stirling design for cost and performance to deliver a 10 kW_{el} system. New adapted tools for small series production had also to be developed to reduce the manufacturing costs for the Stirling engine, and a new installation procedure had to be tested. Finally, a remote monitoring and control system required for cost-effective servicing was to be developed, tested and installed.

The well-proven metal membrane concept applied in former projects has the disadvantage of high erection cost in a single system installation. To overcome this, a new concentrator concept was adopted using a shell built up of 12 reinforced glass-fibre resin sandwich segments on a space frame ring having a net-like structure /European Research 2004/.

Fig. 2-28 EURODISH /Quaschning 2002/

The newly developed components of the two EURODISH systems proved to work easily. In the first system the performances remained below the desired values, whereas in the second one they almost reached the design power output. The cumulated operation time was 300 h within the project duration and a peak power of 10 kW_{el} was achieved. As a result, a new innovative dish/Stirling system has been made available at lower costs, which should open the market for medium-scale production of about 500 units per year.

In the project HYPHIRE, which is the first attempt to develop a hybrid solar-gas concept for dish/Stirling, a hybrid heat pipe receiver for dish/Stirling systems has been developed, allowing reliable power generation independent of solar radiation. This heat pipe transfers any power combination from gas and solar input up to 45 kW_{th} without temperature drop. A new low-cost method producing heat pipe capillary structures has been developed in order to reduce one of the main costs, the manufacture of hybrid heat pipe receivers. An automatic control system has also been developed and implemented.

The result was a successful development of a new hybrid solar receiver. The system was successfully operated in all modes, solar-only, combustion-only and parallel mode of solar and combustion over a period of 360 h. Even operation during cloudy periods could be covered without problems and constant electric power output was assured. Operation has proven to work well, and emission data are encouraging /European Research 2004/.

Three national facilities have been established in Odeillo (France), Seville (Spain) and Würzburg (Germany). They are intended to facilitate the market introduction by their presence in interesting markets. This means that, including the two prototypes at the PSA, a demonstration plant in Milan (Italy) and one in India, there are now a total of seven prototypes currently undergoing tests /Heller 2005/.

- Dish - Farm plants

The concept of Dish - Farm plants has been developed in Australia. After 15 years of experience with direct steam generation in Dish – Farm plants of White Cliffs (**Fig. 2-29**), the Energy Research Centre of the Australian National University of Canberra has designed the world's biggest dish (surface 400 m^2) and has build a prototype.

Fig. 2-29 White Cliffs' solar dish farm /Ransom 2003/

The hexagonal paraboloid consists of 54 triangular mirror-facets mounted on a steel structure which azimuthally tracks the sun. Direct generated steam (540 °C / 42 bar) drives a steam-engine generating 50 kW_{el} of power. In 1997 the construction of a conventional 4 MW_{el} plant, solar-assisted by 25 big dishes, began in Tennent Creek/North Australia. Economic assessments confirm the big potential of such "fuel-saver", especially in those regions where off-grid use is required, like in many parts of Australia and other regions of the world. Power generation can be in those cases very expensive (60 cents per kWh).

The Australian prototype has also been used to investigate high-temperature processes like ammoniac splitting and metal-oxide reduction /ANU 2005/.

2.5.4 Future Development

The following summary is based on publications of the Australian National University, namely /ANU 2005/ as source.

One of the major items contributing to the capital costs of large solar concentrators are the mirror panels. The SG3 400m^2 dish ("Big Dish", **Fig. 2-30**) prototype built by the Australian National University (ANU) has hand-made panels which would be impractical and uneconomic for large production runs.

ANU is therefore attempting to find an optimised design for the first generation of dish-based power plants which will consist of production runs of around 200 dishes. A project supported by the NSW (New South Wales, Australia) Office of Energy has led to the design and production of prototypes. Plans to extend this production to a small-scale pilot production that can be used to replace the SG3 mirror panels are underway.

Fig. 2-30 SG3, “Big Dish” /ANU 2005/

Mirrors using Glass-On-Metal-Laminate (GOML) technology have been developed. They form the optical elements of several reflective solar concentrators designs being produced in the Centre for Sustainable Energy System of the Australian National University. These mirror elements use large sheets of 1mm, back-silvered ‘white’ glass, having 94 % reflectivity and 96 % shape accuracy.

Three-dimensionally curved, spherical panels for use with point focus, large-area dish solar concentrators have been pursued. These panels utilise a sandwich structure, having GOML mirrors as the front skin, a simple metal sheet as a rear skin, and both skins bonded either side of a core-material. This structure shows high flexural rigidity, it is therefore shape-preserving and self-supporting. It also shows high optical accuracy, low weight per unit area and offers low cost of production. These mirrors have undergone several thousand hours of environmental testing at ANU and at research laboratories at Port Kembla, and have shown high resistance to environmental degradation.

Australian researchers are also focusing their attention on thermal storage. One promising method applicable is "closed loop thermochemical energy storage using ammonia".

In this system, ammonia (NH_3) is dissociated in an energy storing (endothermic) chemical reactor as it absorbs solar thermal energy. At a later time and place, the reaction products hydrogen (H_2) and nitrogen (N_2) react in an energy releasing (exothermic) reactor to resynthesise ammonia.

This kind of storage has a lot of advantages. Apart from the ability of the ammonia system to allow for continuous energy supply on a 24-hour basis, other advantages are the non toxicity of constituents involved, reduction of thermal losses (reactant are in a fluid phase) and high energy storage density. Furthermore, the reactions are easy to control and to reverse and there isn’t any unwanted side reaction /ANU 2005/.

2.6 Summary

In this chapter the actual status of the CSP systems' technology has been analysed. After that, an investigation of the main innovations for each system which are expected to take place in the next 15 years has been made. These improvements, considered in the paragraphs "future development", are limited to current demonstrated or tested improvements and with a relatively low rate of deployment. Further scale-up and engineering is necessary in order to make the innovations effective and, of course, a certain risk is associated to this market deployment.

Concerning parabolic trough, the main hopes for future costs' reduction lie in the Direct Steam Generation, which should permit higher operating temperatures (therefore improved turbine efficiency) and lower costs, the developing of new mirrors according to the principle of Fresnel, the improvement of thermal storage and the integration with cogeneration plants. This concept seems to be the one preferred by many investors around the world and many of these Integrated Solar Combined Cycle plants are in the planning phase.

The solar tower, as mentioned above, has still a big innovation potential. The most promising innovation is the use of Beam-down optics, which should allow smaller heliostats fields (20 % less heliostats) and steam generation on the ground, therefore lower costs. As the breakdown of the tower's specific investment costs shows, the heliostats represent one of the major cost driver. For this reason, a big research effort is being made to allow the development in the near-term of new, autonomous heliostats, with thinner and cheaper mirrors. Here, too, the use of towers in hybrid plants should bring the LEC to values only slightly higher than conventional plants.

The concept of the solar dish, on the contrary, shows a minor potential of innovation. The scaling-up of the existing dishes, which has led to the development of "Big Dish", will remain without effect if mass-production will not occur. In fact, the production of the mirror elements of "Big Dish" is at present too expensive. Improvements in the structure and the material of the paraboloid has been made, leading to the development of the "Glass-on-Metal-Laminate" design, along with progress in the thermal storage.

All these expected future developments, together with a synthetic description of the main features of already existing technologies, is shown below (Fig. **2-31**):

	Trough	Tower	Dish
Actual technology	Only commercial CSP Single-axis tracking HTF: oil (400 °C) Efficiency: 14-18 %	High temperatures (till 1100 °C) Double-axis tracking HTF: molten salt Efficiency: 18-20%	Off-grid operation Three-axis tracking Dish/Farm or Dish/Stirling Efficiency: 27 %
Future development	DSG (Direct Steam Generation) Principle of Fresnel Latent Thermal Storage New Receiver	Beam down optics Thin glass heliostats Autonomous heliostats Hybrid operation	"Big Dish": 400 m^2, 80 kW_{el} "GOML" (Glass-On-Metal-Mirrors) Thermo-chemical storage using ammonia

Fig. 2-31 Actual technology and future developments of CSP systems

For the European researchers, there are two main points to concentrate on: firstly, increasing the operating temperatures in order to achieve better energy efficiency, and secondly developing thermal energy storage units that will help to compensate the drop in power when clouds pass across, enabling peak-demand to be satisfied and making possible to extend the power station's useful operating hours /Szodruch 2005/.

Trough technology is further advanced than tower technology, since it has 354 MW_{el} of commercial generation experience in the south-western United States. Trough technology is a fully mature technology, and there is low technical and financial risk in developing near-term plants. The long-term projection has a higher risk due to technology advances needed in thermal storage. On the other hand, tower technology has been successfully demonstrated with a conceptual and a pilot plant (Solar One and Solar Two). This kind of technology needs to proceed from demonstration to commercial development. There is a higher technical and financial risk in developing a first-of-its-kind commercial plant. The advantage of tower technology is that its big innovation potential could result, for long-term deployment, in lower costs than parabolic trough, if commercial development is successful (e.g., if expected cost and performance targets are achieved).

The objective of all this R&D work is to advance the technology for CSP systems thus they are ready for the market within 15 years and thus solar electricity can approach competitiveness with the electricity generated from fossil fuels in conventional power stations.

3 Costs of CSP

Solar thermal power is one of the main candidates to provide a major share of renewable energy needed in the future because it's among the most cost effective renewable power technologies with near-term power generation costs in the range of 0,14 to 0,19 $€_{2005}$/kWh and of 0,09 to 0,15 $€_{2005}$/kWh for long-term considerations /Ferriere 2005/. Compared with photovoltaic, it is the lowest cost solar electricity in the world, promising cost competitiveness with fossil-fuel plants in the future. In 2003 there was a total of 2.7 GW_{el} demonstration projects in the pipeline, which represents more than 10 million m^2 of solar collector field. Most of these projects aim to begin commercial operation before 2010 /European research 2004/.

This chapter will give an overview of the costs of CSP, which depend basically on four criterions: investment costs, O&M (operational and maintenance) costs, the availability of solar resources and political decisions (this last criterion will not described in the present study, which is focusing primarily on the technical and economical issues of CSP systems).

The evaluation of costs in suitable sites determine the economical potential, i.e. the feasibility of CSP, which is then used to develop strategies for their market introduction.

3.1 Solar resources

To determine the electricity yield first of all a suitable place has to be chosen. Geographical Information Systems (GIS) are suitable for this purpose and they are increasingly used worldwide in infrastructure and project planning. These systems are based on satellite remote sensing, which can offer many advantages. One of them is that they measure the components with constant quality over the whole area and the historic data is stored in archives. Therefore entire regions can be evaluated without travelling into them and long periods can be analyzed without the need for long and expensive measurements on the location. Moreover, satellite based solar irradiance data has a higher significance than ground based data, because irradiance itself varies from year to year and long term ground measurements are almost never available.

The results are maps of the direct normal irradiance in kWh/m^2 and influence of clouds, aerosols and water vapour, data which can help investors to analyse how much energy can be gained at a certain site before construction begins. Moreover satellites can be used for near real time information of the electricity yield and to adjust components. A further option is the forecast of solar irradiance for up to 48 hours (project ENVISOLAR of DLR), which can be used for optimized operation of solar and conventional power plants /Trieb 2005/.

Satellites show that solar thermal installation do not appear to be economical on sites with normal irradiance below 1.800 kWh/m^2a. Therefore in the Mediterranean Sea (**Fig 3.1**), for example, areas north of the 40^{th} parallel seem to be of little or none interest /Klaiss 1992/.

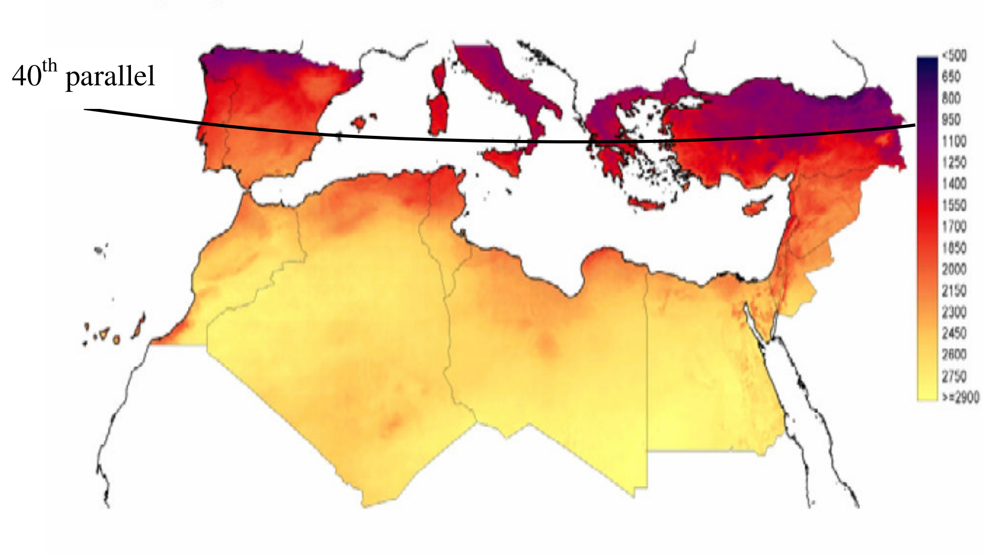

Fig. 3-1 Solar radiation distribution on the Mediterranean Sea /ECOSTAR 2005/

In the following chapters the investment costs and O&M costs for the different CSP systems will be analysed. A comparison between costs near-term and middle-term plants will be made, in order to show which impact can the cost reduction drivers have.

3.2 Parabolic trough

We will consider the experience of the Californian SEGS plants, which have been using LS-3 collectors, because they are till now the only commercial parabolic troughs existing, allowing a much simpler survey of the different investment and O&M costs. This is important in order to identify the cost trends and the future perspectives.

3.2.1 Investment costs

The investment costs are made up of construction, connecting to infrastructure, insurance and capital costs. They are sometimes defined as EPC (Engineering, Procurement and Construction) costs. The single most important cost elements for the parabolic trough are those associated with the concentrator optics and associated means of absorbing concentrated solar energy.

In order to evaluate the investment costs for a 50 MW_{el} plant, an important source is the Global Environmental Facility (GEF), which reports the original investment's costs of the nine SEGS plants. It can be noticed that these costs have been decreasing from the original value of 4.500 $US\$_{1984}$/kW of the first plant (SEGS I, 15 MW_{el}, 1984) to less than 3.000 $US\$_{1989}$/kW (SEGS IX, 1989), the main cause being the scaling up in the plant size and the resulting mass production. Taking into account the inflation rate, these values would be 6.820 $US\$_{2005}$/kW (SEGS I) and less than 4.000 $US\$_{2005}$/kW (SEGS IX) respectively /GEF 2001/. This is confirmed by a study from /Squire&Sanders 2005/, which show s that the costs have been falling from $US\$_{2005}$ 6.820 (SEGS I) to $US\$_{2005}$ 3.947 (SEGS IX). The exact trend data of these costs is given in the following table (**Fig. 3-2**) /Squire Sanders 2005/.

Plant	Year	Sum of installed Power $[MW_{el}]$	Specific Investment Costs	Specific Investment Costs $[\$_{2005}/kW]$
SEGS I	1984	15	4.500 $[\$_{1984}/kW]$	6.820
SEGS II	1985	45	4.500 $[\$_{1985}/kW]$	6.687
SEGS III-VII	1987	195	3.400 $[\$_{1987}/kW]$	4.856
SEGS XIII-IX	1989	355	2.875 $[\$_{1989}/kW]$	3.947

Fig. 3-2 Investment costs development in SEGS plants

On the basis of this data, we have constructed a Learning Curve, which describes how cost declines with cumulative production. A characteristic of learning curves is, in particular, that the cost declines by a constant percentage with each doubling of the number of units produced. The curve, which can be plotted on a linear or a log-log scale, is generally expressed as:

$$C_{CUM} = C_0 \cdot CUM^b$$

where C_{CUM} = cost per unit as a function of input

C_0 = cost of the first unit produced

CUM = cumulative production over time

b = experience index

The experience index is used to calculate the relative cost reduction, $\left(1-2^b\right)$, for each doubling of production:

$$\frac{C_{CUM1} - C_{CUM2}}{C_{CUM1}} = 1 - \frac{C_0 \cdot \left(2CUM_1\right)^b}{C_0 \cdot CUM_1^b} = 1 - 2^b$$

The value $\left(2^b\right)$ is the progress ratio (PR), which expresses the progress of cost reductions. We have calculated a progress ratio of 0,89 for the period 1984-1989 (period of construction of the SEGS plant) and it was possible afterwards to extrapolate a trend for the future plants. Choosing the PR above means that costs are reduced by 11 % each time the cumulative production is doubled. This is shown in the picture below (**Fig. 3-3**). A World Bank study projected a reasonable experience curve for parabolic trough with a progress ratio between 0.85 and 0.92 (/S&L 2003/, according to /World Bank 1999/).

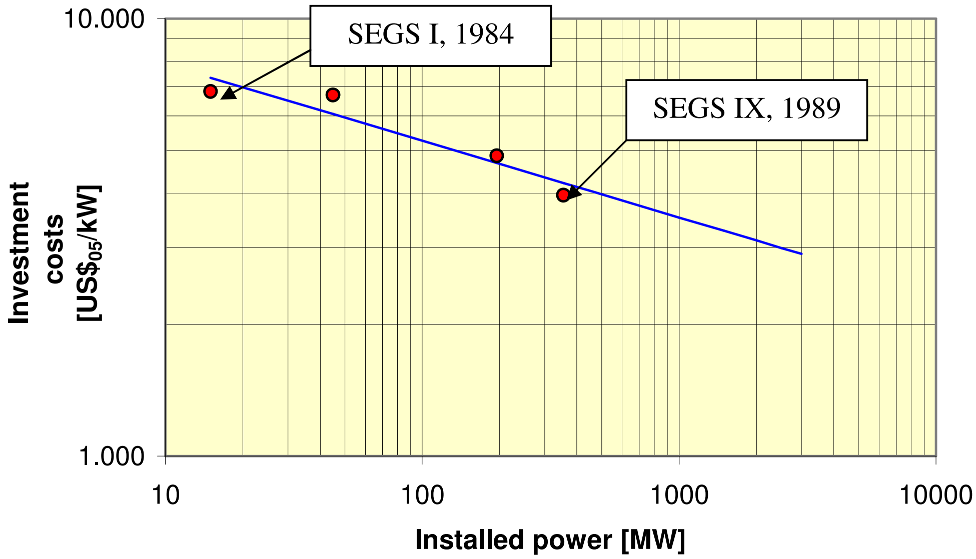

Fig. 3-3 Learning Curve of investment costs for Parabolic Trough (own calculations, /Squire&Sanders 2005/)

On the basis of the same data a 1999 Wold Bank study had estimated investment costs for a plant to be built in 2000 ranging from 3.600 US$$_{2005}$/kW (30 MW$_{el}$ plant) to 2.500 US$$_{2005}$/kW (200 MW$_{el}$ plant).

On the other hand in 2003 other studies, namely /Sargent & Lundy (S&L) 2003/ and /Internationale Energieagentur (IEA) 2003/, made different previsions. The first one estimated 4.816 US$$_{2003}$/kW for a 50 MW$_{el}$ near-term plant (2004) with a 12 hours storage, the second 2.800 - 3.200 US$$_{2003}$/kW for a 50 MW$_{el}$ near-term plant and 2.200 - 2.100 US$$_{2003}$/kW for a mid-term one (both without storage) /S&L 2003/, /IEA 2003/. These cost forecasts are in accordance with those resulting from the most recent assessments for the Andasol plant (6 hours thermal storage), which is likely to become operative in 2007.

Actual values of the investment costs necessary for a parabolic trough plant are also based on economic assessments made for Andasol. Publications of the European research, reporting anticipation given by project's partners, suggest that the two units of 50 MW$_{el}$ each with 3 hours thermal storage, based on the EUROTROUGH design, should have an installed cost of less than 3.000 €$_{05}$/kW, but we should remember that the experimental loop had a power output of 1 MW$_{el}$, therefore different cost figures are possible. As reported in the previous chapter, this is a result of the projects completed on the PSA, which showed that EUROTROGH design (the one used in Andasol) achieves a 15 % cost reduction when compared with the existing LS-3 collector /European Research 2004/.

Another recent source is the ECOSTAR report /ECOSTAR 2005/ published by the DLR, major partner of the Eurotrough projects. In this paper an assessment of the 50 MW$_{el}$ module of Andasol, with 3 hours storage, has been made, again using the SEGS plant as reference system. 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 the improved collector design /ECOSTAR 2005/. This is the only figure in accordance with the studies mentioned above.

For DLR the investment costs are estimated to be around 4.200 €$_{05}$/kW, but the authors themselves note that numbers may deviate significantly from real project costs /ECOSTAR 2005/.

As we have seen in the previous chapter, this plant is made up of a conventional thermal plant (boiler, steam turbine generator and balance of plant, eventually a gas turbine and a waste heat recovery system) and of a solar boiler (solar field and heat transfer fluid system), eventually a thermal storage. In the following pictures we can see a near-term prevision for an investment breakdown according to /S&L 2003/, which considered a 100 MW$_{el}$ plant and the presence of a 12 hours thermal storage (**Fig. 3-4**):

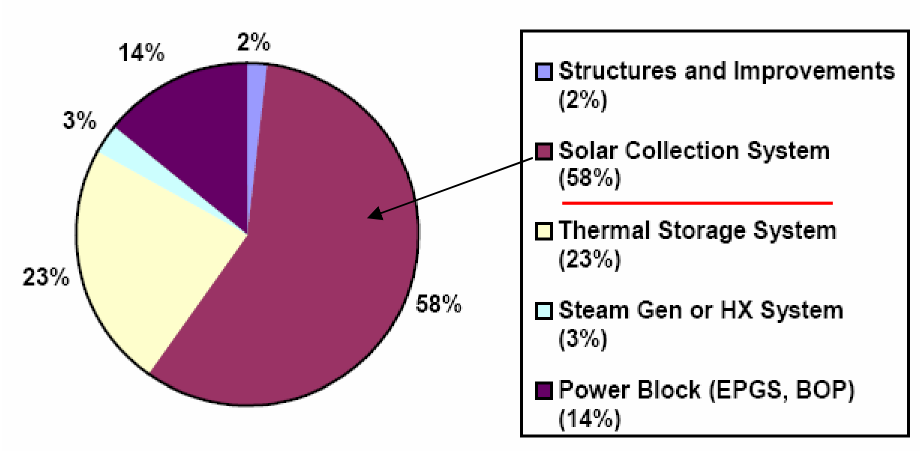

Fig. 3-4 Investment costs' breakdown for a 100 MW$_{el}$ trough plant with 12 hours storage /S&L 2003/

As it can be seen, the biggest part of the investment is given by the Solar Collection System (i.e. the solar field), which is also the youngest technology element, consequently the part which is most sensible to R&D and scaling-up effects. In the following picture (**Fig. 3-5**) the cost breakdown of the solar field equipment is shown.

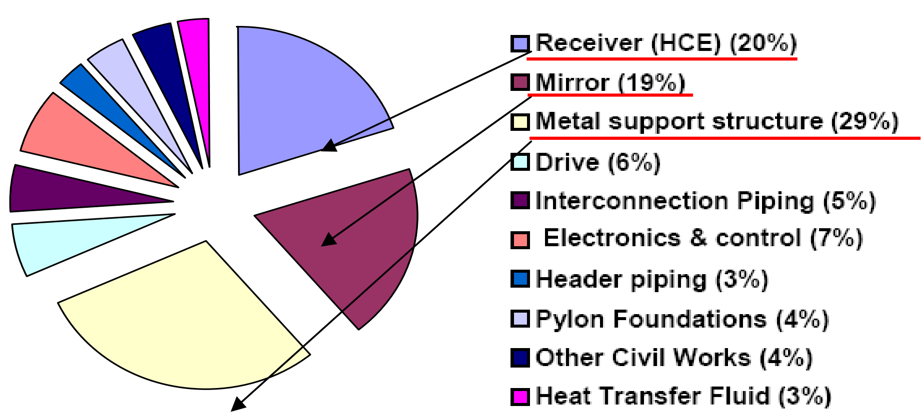

Fig. 3-5 Investment costs' breakdown for the solar field /S&L 2003/

It can be noticed how the biggest influence on the costs is exerted by the receiver (Heat Collecting Element, HCE), the mirror and the metal supporting structure. Therefore these are the fields where the biggest R&D efforts have to be made in order to achieve a substantial cost reduction, which will be quantified later on.

Looking at the data from the European ECOSTAR study /ECOSTAR 2005/, although the authors explicitly dissuade from making a global cost comparison (because of the different level of maturity), they come to the same conclusion as /S&L 2003/, i.e. that the solar field represents the largest cost share. The projects completed or undergoing on the PSA clearly show that the European Consortium has decided to direct their efforts into the same fields of research proposed by the American assessments.

We will now examine how the costs of a CSP plant can be reduced. There are basically two main ways:

1) Research & Development (R&D): improvement in the basic subsystem designs like, for example, lighter weight structures, less expensive mirrors made from alternative materials, and lower cost tracking
2) Experience resulting from larger production volumes, resulting in a reduction of per-unit costs ("Learning Curve")

R&D

We shall consider R&D at first. /S&L 2003/ in fact estimates that the costs of a parabolic trough plant can be reduced by roughly 50 % in the next 15 years. The /S&L 2003/ analysis found that cost reductions were due 29 % to R&D.

Referring to the cost split-up seen above, and examining in more detail the solar boiler related equipment, we find that about 49 % of the total solar scope is highly technology-specific, consisting of: heat collection (heat collection elements and reflectors), solar field electronics, heat transfer fluid (HTF), HTF vessel and heat exchangers, HTF pumps. We remind that the HTF is a synthetic oil.

Heat collection elements and parabolic reflectors are the only elements which have unique or limited suppliers. Other significant solar field cost items such as the structural steel, hydraulic drives and field installation do not require specialized knowledge. This non-technology specific equipment can be competitively bought on a worldwide market. Moreover, the presence of such a big share of these elements allows a cheaper supply of them /S&L 2003/.

As we have seen above, the costs of a CSP system can be split into solar costs and non-solar costs. R&D can be effective in reducing the solar costs if it will succeed in developing innovative mirror systems, the solar collectors which currently constitute 30 – 40 % of the present plant investment costs, along with the development of novel optical systems. Non-solar costs will be reduced by the development of simpler and more efficient heat transport schemes, more efficient power cycles, direct steam generation, integration with conventional systems, and increases in steam temperature to improve the efficiency of the steam cycle for electricity generation.

In particular an important solar costs reduction potential lies in the collector (minimizing collector weight due to improved design and simulations will lower costs) and in high efficiency and durable receiver. This will result in smaller solar fields for a given thermal energy delivery and in longer lifetimes, thus reducing operation and maintenance costs. Alternative mirror design development using thin-glass with non-metallic structural elements is also assumed, reducing weight while alternative HTFs, such as inorganic molten salts and ionic fluids which will permit operation at higher temperatures (at or above 500°C). They will lead to lower thermal storage costs and higher power block efficiencies. Substantial cost reductions are also expected from the thermal storage system, with a single-tank (instead of two, with a heat exchanger) direct molten salt system. Minor but nevertheless important is the improvement of the electric power block. We have to remind that the efficiency of a SEGS-type plant is improved by refining the integration of the solar field with the power block. For instance, the projection of /S&L 2003/ for the thermal storage is shown in **Fig. 3-6** (the reference case is SEGS VI-1987, costs are expressed in U$$_{2003}$) /S&L 2003/:

Year	**2004**	**2007**	**2010**
Plant size [MW_{el}]	110	110	165
Storage [MWh_{th}]	3.535	3.349	4.894
Type	Indirect, two tanks	Direct, single tank	Direct, single tank
Heat transfer fluid (HTF)	Molten Salt	Molten Salt	Molten salt
HTF temperature [°C]	400	450	500
SunLab costs [$/$kW_{el}$]	958	425	383

Fig. 3-6 R&D costs reduction for Thermal Storage /S&L 2003 according to SunLab 2001/

The reduction potential for the Solar Collection System, the Thermal Storage and the Power Block trough R&D is summarized in **Fig. 3-7**, which like previously refers to SEGS VI as baseline and expresses costs in U$$_{2003}$. The data from SEGS VI are from 1989, therefore expressed in U$$_{1989}$.

	Baseline	Near-Term	Mid-Term
Plant	SEGS VI	Andasol ($50 MW_{el}$)	150 MW_{el} trough
In service	1987	2007	2010
Support Structure [$/m^2$]	67	61	54
HCE [$/unit]	847	847	635
Mirrors [$/m^2$]	43	43	28
Power Block [$/kW_{el}$]	527	367	293
Thermal Storage [$/kW_{el}$]	-	958 (12 hours)	383 (12 hours)
Other components [$/m^2$]	250	234	161
Total Plant Cost, according to SunLab [$/kW_{el}$]	3.008 $U\$_{1989}$ /kW_{el}	4.856 $\$_{2003}$/$kW_{el}$	3.416 $\$_{2003}$/$kW_{el}$

Fig. 3-7 Summary of investment costs expected reduction by R&D for a Parabolic Trough plant /S&L 2003/.

SCALING UP

Concerning scaling up, we have to point out that the economics of a CSP installation is strongly dependent upon its size. The experience accumulated in the projects funded by the EU makes clear that nowadays the minimum size for a parabolic trough system is 50 MW_{el}. Mass production leading to economies of scale is seen to be particularly effective in costs reduction if correlated to solar costs, because the non-solar costs are already a result of the wide-spread conventional technology /European Research 2004/.

For Sargent & Lundy /S&L 2003/ the "Learning curve" arguments seem to be less credible, given the fact that the materials of construction are already commodities and the fabrication techniques, for the most part, standard. This nevertheless can be an advantage in terms of scaling-up and in fact some "Learning curve" based cost reductions would be expected. This can be clearly seen in the /S&L 2003/ study which, we remember, estimates a total costs' reduction potential of roughly 50 % in the next 15 years, of which 21 % are due to volume production /S&L 2003/.

An IEA report suggests that in the same period the costs will be reduced by 30 %:

- up to 25 % from volume production (Learning Curve)
- up to 5 % from R&D

Therefore, like most European researchers think, scaling-up is seen as a key-medium for costs' reduction. This because after 20 years of researches on the PSA and 20 years of SEGS plant operation, the technology based on mineral oil as transfer medium seems to be already mature and only needs market expansion in order to benefit from further sensible cost reductions after the ones observed in the SEGS experience /NET Switzerland 2003/, /ECOSTAR 2005/.

Of particular importance are issues on how "Learning curve" cost reductions would be distributed across the value chain (materials, factory fabrication, site fabrication, site preparation, installation). In this case the actual strategy employed by the plant suppliers can be significantly diverse. We have reported data with emphasis on near-term or mid-term (2010) cost reduction only, being this one the option with a minimum of risk. Recognized scaling-up effects (for an installed power of 455 MW_{el}) have been until now reported for three main elements /S&L 2003/:

- HCE: Schott Rohrglas is strongly increasing its production
- Mirror fields: mass production can lower the costs significantly. SunLab projected a cost reduction of 10 % till 2007 and 30 % till 2010 /S&L 2003/. Other studies have shown that doubling the size of the field reduces the capital costs by 12-14 % /NET Switzerland 2003/.
- Power Block

For DLR the improvements in the basic subsystem and the subsequent level of cost reduction which can be achieved while still maintaining required performance and reliability are the central issues associated with assessing the commercial potential of the solar trough. However substantial (not quantified by ECOSTAR) reductions in investment costs are likely via a combination of the two factors mentioned above.

Other factors that can influence the amount of investments costs are related to the local logistics, like land cost and water availability (e.g. for Andasol the land will cost 2 €/m^2, but for SEGS the desert land was purchased at "zero" cost), or to financial circumstances. In fact CSP are capital-intensive and the cost of capital and the type of project financing can have a significant impact on the final costs of power /NET Switzerland 2003/. These factors are different for each plant, therefore a comparison has not been made .

In conclusion, it can be seen that American studies forecast that a big cost reduction (about 50 %) is still possible for CSP systems. According to these studies, a big potential lies in R&D (29 %) /S&L 2003/.

This has been shown in the previous figures. However, mass-production plays also a major role in this process, contributing to it with 21 % /S&L 2003/. On the contrary European researchers, which have been improving the oil-based technology for more than 20 years, indicate that a reduction of about 30 % can be achieved /IEA 2003/, but R&D doesn't have a big potential (5 %), while mass-production can still allow a 25 % cost fall /ECOSTAR 2005/. The costs' reduction potential is summarised in thee following figure (**Fig. 3-8**).

Plant type	Near-term plant	Future plant	Near-term plant	Future plant
Year of construction	2004	2020	2005	2020
Power	50 MW_{el}	400 MW_{el}	50 MW_{el}	50 MW_{el}
Storage	12 hours	12 hours	3 hours	3 hours
Capital costs	4.816 $US\$_{2003}/kW$	2.400 $US\$_{2003}/kW$	4.200 $€_{05}/kW$	2.940 $€_{05}/kW$
Reduction due to R&D	29 %		5 %	
Reduction due to mass production	21 %		25 %	
Total reduction	50 %		30 %	
Source	/S&L 2003/		/ECOSTAR 2005/	

Fig. 3-8 Summary of costs' reduction for the parabolic trough /S&L 2003/, /ECOSTAR 2005/

The European researchers don't expect a major technological break-through in the near-term to have a significant impact, since for instance Direct Steam Generation still needs long improvements to be competitive and reliable. From the previous considerations it seems clear that a future cost reduction is expected to come from both the two most important factors highlighted. In fact, as pointed out above, the biggest part of the investment (58 %) is given by the Solar Collection System, which is also the youngest technology element, consequently the part which is most sensible to R&D and scaling-up effects.

3.2.2 O&M costs

The /PRICE 2003/ O&M estimate is based on the experience of SEGS plants, in particular of SEGS III-VII between 1997-2001. This is important especially for the HCE replacement rate, assuming the failure of this component to be the one with the highest risk to happen (prediction for Andasol 2007: 0,5 % / year).

/PRICE 2003/ reviewed the O&M cost model based on the experience with fossil and other power plant technologies and in the course of a site visit to KJC (Kramer Junction Operating Company), the operator of the five 30-MW_{el} trough projects located at Kramer Junction. KJC provided proprietary information on five years of operation. The O&M estimate is based largely on the experience at the KJC Operating Company SEGS plants. The model assumes a stand-alone trough power plant (as opposed to the five co-located plants at Kramer Junction) and adjusts cost depending on the size of the solar field and total electric generation per year. It breaks out the specific staffing requirements for operation and maintenance crews for both the conventional power plant and for the solar field. Administrative staffing is also included. In addition to labor breakdown, the model breaks out parts (mirrors, hydraulic drivers, HTF pump seals, etc.) and equipment costs.

The next figure (**Fig 3-9**) shows a summary of the different O&M cost drivers for a 50 MW_{el}, 6 hours storage parabolic trough, based on data from the SEGS plants in California and to be built in the near-term. The capital costs for such a plant are expected to be around 241 Mio $\$_{2003}$:

	Staff	Labor [k$\$_{2003}$/yr]	Parts [k$\$_{2003}$/yr]	Equipment [k$\$_{2003}$/yr]	Total [k$\$_{2003}$/yr]
Administration	7	440	253	0	693
Operation	13	746	249	0	994
Power Block Maintenance	8	527	314	0	841
Solar Field Maintenance	7	391	600	90	1.081
Total	35	2.104	1.416	90	3.610
Fraction of capital costs [%]	-	0,8	0,5	0,03	1,49

Fig. 3-9 Summary of O&M costs for parabolic trough /PRICE 2003/

The model of parabolic trough which has been assessed examines O&M cost in relation to capital costs and it will be useful to assess the value of R&D efforts, help optimize plant designs, and support commercial project development efforts.

3.3 Solar tower

We will consider the experience of the American Solar Two, which, as a demonstration plant, has been shut up but has provided for a long time a successful series of data, and PS10 (Planta Solar 10), whose construction has begun in 2005 and therefore has been assessed in detail /ECOSTAR 2005/. We will focus on the Spanish project Solar Tres, which is based upon the Solar Two design (it's in fact its natural consequence) and whose construction is also planned to be completed in 2006 /SolarPaces 2005/. This last plant has been assessed in detail by a /S&L 2003/ study and by the /ECOSTAR 2005/ study. In the latter case the information on costs have been gained by DLR according to SolarPaces' data or extrapolated from the PS10 project, which is also a Solar Tres-type plant but uses an air-receiver instead of molten salt. It has a power of only 10 MW and a thermal storage of 50 min, therefore is not very useful for comparisons. However, like Solar Tres, the know-how for its design has been also gained from Solar Two, therefore we will refer to the latter plant for analysis.

3.3.1 Investment costs

As pointed out in the previous chapter the most important cost elements for the solar tower are those associated with the concentrator optics and associated means of absorbing concentrated solar energy, in particular the heliostats. The total investment costs for a 50 MW_{el} plant with three hours storage are between 177 Mio $€_{05}$ (3.473 $€_{05}$/kW) for a Solar Tres-type plant (molten salt) and 200 Mio $€_{05}$ (3.920 $€_{05}$/kW) for a Solar Tres-type plant with air-cooled receiver (PS10), while generation costs currently range between 15 and 20 €cents/kWh /ECOSTAR 2005/.

Solar Two, with 10 MW_{el} of power (4 hours storage), had total investment costs of about 5.570 $US\$_{2003}$/kW /SANDIA 1996/. Because of its small size is has been considered not economically feasible; therefore we will concentrate on cost projections made for the European Solar Tres, which is basically a scaling up of its American smaller sister but will be built in Spain. The first module will have a size of 17 MW_{el} and a huge thermal storage of 16 hours, but at its final stage, with 3 modules built, it will have a power output of about 50 MW_{el} /ECOSTAR 2005/. Assuming the construction to be completed in 2007 it is expected that such a plant will have a cost of about 3.708 $€_{05}$/kW for a 17 MW_{el} plant and 2.726 - 3.152 $€_{05}$/kW for a 50 MW_{el} one (own calculations, /ECOSTAR 2005/). If completed in 2007, PS10 should have a cost of 3.500 $€_{05}$/kW /SolarPaces 2005/.

Concerning a near-term (2010) perspective too, the /S&L 2003/ study estimates that the costs for a 100 MW_{el} plant with 13 hours storage will drop to about 3.060 $US\$_{2003}$/kW. A Solar Tres-type (i.e. in the range of 15 MW_{el}) to be built in the USA has also been planned. The results are shown below (**Fig. 3-10**):

Plant type	Solar Two	Solar Tres-type USA	Solar Tres Spain	Solar Tres Spain	Near-term plant
Year of construction	1996	Planned	2007	2007	2010
Power	10 MW_{el}	14 MW_{el}	17 MW_{el}	50 MW_{el}	100 MW_{el}
Storage	4 hours	16 hours	16 hours	16 hours	13 hours
Specific Costs	5.570 $US\$_{2003}$/kW	7.100 $US\$_{2003}$/kW	3.708 $€_{05}$/kW	2.726 - 3.152 $€_{05}$/kW	3.060 $US\$_{2003}$/kW
Source	/SANDIA 1996/	/S&L 2003/	/ECOSTAR 2005/	/ECOSTAR 2005/	/S&L 2003/

Fig. 3-10 Investment costs' evolution from Solar Two to near-term plants (own calculations, /SANDIA 1996/, /S&L 2003 according to SunLab/, /ECOSTAR 2005/)

However, before discussing these cost reductions and how they can be achieved, a costs' breakdown of a state-of-the-art plant (Solar Tres-type) is necessary.

According to /S&L 2003/ the major cost components for a solar tower are the solar field, electric power block and receiver, which cover approximately 64 % of the total direct costs (about 7.110 $US\$_{2003}$/kW) as shown in **Figure 3-11**. Therefore the study focused on these three main elements. The major cost component is the heliostat field, which counts for 38 % of the total costs of Solar Tres /S&L 2003/.

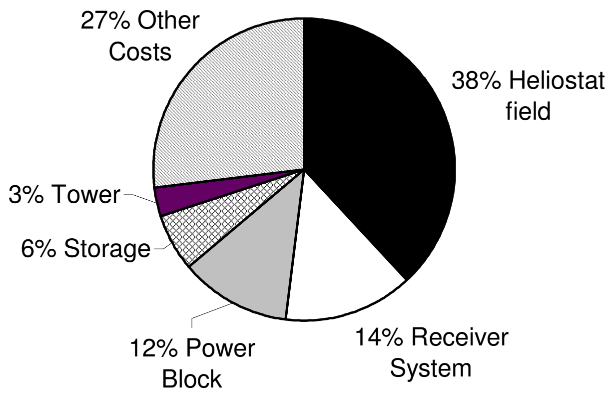

Fig. 3-11 Investment costs breakdown for Solar Tres (own calculations, /S&L 2003/)

It must be remembered that Solar Two, the smaller version of Solar Tres, has been constructed and operated in the U.S.A. and /S&L 2003/ was the official institution to be commissioned by the government for its assessment. Therefore /S&L 2003/ had the possibility to get access to the plant structures, management, personnel and databases, gaining a comprehensive amount of updated real data. However, except for the cost of the power block and the thermal storage, the breakdown shown above is similar to the one predicted by /ECOSTAR 2005/ in the picture below (**Fig. 3-12**):

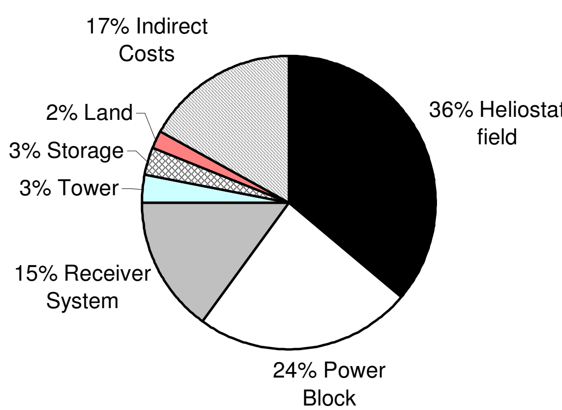

Fig. 3-12 Investment costs breakdown for Solar Tres /ECOSTAR 2005/

Given the previous figures, it’s clear why, while examining how the costs of a solar tower plant can be reduced, the review will focus on only three basic elements: heliostats, power block and receiver.

As for the parabolic trough, there are basically two main ways to reduce costs:

1) Research & Development (R&D): as underlined above, improvement in the basic subsystem of the heliostats, like lighter weight structures, less expensive mirrors made from alternative materials, and lower cost tracking are needed.
2) Experience resulting from larger production volumes, resulting in a reduction of per-unit costs ("Learning Curve")

R&D

R&D will be considered first. /S&L 2003/ estimates that the costs of a Solar Tres plant (17 MW_{el}, 16 hours storage), considered as baseline, can be reduced by roughly 56 % in a 100 MW_{el} plant to be built in the next 5 years. These are the quotas of the cost reductions due to R&D found by the /S&L 2003/ analysis in relation to the three elements mentioned above: heliostat 5 %, power block 1 %, receiver 37 %.

Concerning the /ECOSTAR 2005/ study, it has been found that the following reductions can be achieved (in the near-term) due to R&D in a 50 MW_{el}, Solar Tres-type plant (with 16 hours of thermal storage): heliostats between 15 % and 22 %, power block between 7 % and 27 % and receiver between 21 % and 50 %. The results are summarized below (**Fig. 3-13**):

	/S&L 2003/ Initial cost [U$$_{03}$/kW]	/S&L 2003/ Final cost [U$$_{03}$/kW]	Reduction [%]	/ECOSTAR 2005/ Initial cost [€$_{05}$/kW]	/ECOSTAR 2005/ Final cost [€$_{05}$/kW]	Reduction [%]
Heliostat	2.700	2.557	5	1.335	1.044 - 1.137	15 – 22
Power Block	852	844	1	890	650 - 827	7 - 27
Receiver	994	622	37	556	278 - 434	22 – 50
Other components	2.554	1.733	32	927	927	-
Total	7.100	5.796	18	3.708	2.899 - 3.325	10 – 22

Fig. 3-13 Expected investment costs reduction of the main cost drivers from R&D (own calculations, /S&L 2003/, /ECOSTAR 2005/)

/ECOSTAR 2005/ considered a 50 MW_{el}, Solar Tres plant as baseline and has also found the heliostats to be the most expensive component of the plant. Therefore, according to one of the major Spanish partner, SENER, it has considered a more detailed split-up of its heliostat costs, as can be seen in the following picture (**Fig. 3-14**) :

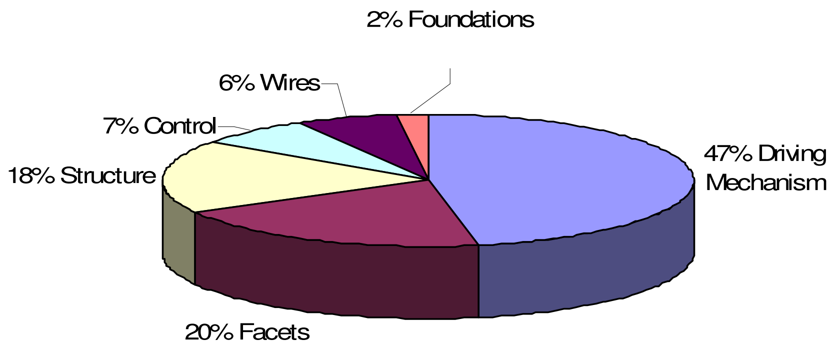

Fig. 3-14 Heliostat costs breakdown /SENER 2004/

It can be clearly seen that the most expensive component is the driving mechanism, followed by the facets and the supporting structure. /ECOSTAR 2005/ found that in less than 5 year a new driving system should be enter the productive phase, allowing a decrease of its costs between 10 % and 20 %. Concerning the facets, increasing their optical properties (and the efficiency) is seen as an indirect way to decrease the LEC costs, but the investment costs will be only slightly directly effected (5 - 10 %). The structure is expected to undergo developments which can result in a 20 - 30 % cost reduction. Wireless heliostat (each heliostat will be autonomous and will not be connected with cables to main control system) fields can also provide a further 6 % reduction of the overall costs. By combining all these measures, an overall costs fall between 15 % and 22 % is expected for the heliostats, as shown in **Fig. 3-13** (own calculations, /ECOSTAR 2005/). The R&D achievements expected by /ECOSTAR 2005/ are summarized below (**Fig. 3-15**):

	Solar Tres 2007 [$€_{05}$/kW]	Expected (5-10 years) [$€_{05}$/kW]	Reduction [%]
Driving system	627	502 - 564	10 - 20
Facets	267	240 - 253	5 - 10
Structure	240	168 - 192	20 - 30
Other components	201	201	-
Baseline Total	1.335	1.111 - 1.210 1.044 - 1.137*	15 - 22 *

*) inclusive 6 % reduction from wireless driving system

Fig. 3-15 Investment costs breakdown for Solar Tres (own calculations, /ECOSTAR 2005/)

On the other hand, for /S&L 2003/ R&D should lead in 5 years to an overall reduction for the heliostats of 5 %, from 2.700 U$$_{03}$/kW to 2.557 U$$_{03}$/kW /S&L 2003/.

SCALING UP

Considering the plant scaling-up, it must be pointed out that this factor can be particularly effective in reducing the cost of the heliostats. The /S&L 2003/ study considered a deployment of 1,4 GW$_{el}$ in the next 5 years and an increase in the heliostat's surface from 95 m^2 to 148 m^2. It has estimated that the mass-production can contribute with a share of 43 % to the cost fall of the actual heliostats to be deployed in the 17 MW$_{el}$ Solar Tres (as always, target case is a 100 MW$_{el}$ Solar Tres). The power block will achieve a big part of cost reductions due to the scaling-up effect, about 45 %, while the receiver will be affected by around 37 % /S&L 2003/.

The /ECOSTAR 2005/ has assessed the scaling-up of the first 17 MW$_{el}$ module of Solar Tres to a 51 MW$_{el}$ plant, finding the following cost reductions: heliostats 5 %, power block 7,5 %, receiver 7 %. This scaling-up alone is responsible for a decrease of the total investment costs of the plant of about 5 % (own calculations, /ECOSTAR 2005/). The results are summarized below (**Fig. 3-16**):

	/S&L 2003/ Initial cost [U$$_{03}$/kW]	/S&L 2003/ Final cost [U$$_{03}$/kW]	Reduction [%]	/ECOSTAR 2005/ Initial cost [€$_{05}$/kW]	/ECOSTAR 2005/ Final cost [€$_{05}$/kW]	Reduction [%]
Heliostat	2.700	1.543	43	1.335	1.268	5
Power Block	852	466	45	890	823	7,5
Receiver	994	622	37	556	517	7
Other components	2.554	1.733	32	927	927	-
Total	7.100	4.364	38	3.708	3.535	5

Fig. 3-16 Cost reduction comparison due to mass-production (own calculations, /S&L 2003/, /ECOSTAR 2005/)

In conclusion /S&L 2003/ expects a cost reduction potential for a near term, 100 MW$_{el}$ plant (16 hours storage) of about 56 %, from 7.110 U$$_{03}$/kW to 3.060 U$$_{03}$/kW. Considering the main cost drivers (heliostats, power block and receiver), the study found that they can achieve the following global reductions (own calculations, /S&L 2003/):

- Heliostats from 2.700 U$$_{03}$/kW to 1.400 U$$_{03}$/kW
- Power block from 852 U$$_{03}$/kW to 458 U$$_{03}$/kW
- Receiver from 994 U$$_{03}$/kW to 250 U$$_{03}$/kW

The results are summarised in the figure below (**Fig. 3-17**):

	/S&L 2003/ Initial cost [U$$_{03}$/kW]	Reduction due to R&D [%]	Reduction due to mass-production [%]	Total Reduction [%]	/S&L 2003/ Final cost [U$$_{03}$/kW]
Heliostat	2.700	5	43	48	1.400
Power Block	852	1	45	46	458
Receiver cost	994	37	37	75	250
Other components	2.554	32	32	62	992
Total	7.100	18	38	56	3.060

Fig. 3-17 Summary of costs reduction according to /S&L 2003/

On the other hand the /ECOSTAR 2005/ study expects a cost reduction potential for a near term, 50 MW_{el} plant (16 hours storage) of 15 – 26 % from 3.708 €$_{05}$/kW to 2.726 - 3.152 €$_{05}$/kW. Considering the main cost drivers (heliostats, power block and receiver), the study found that they can achieve the following reductions (see **Fig. 3-18**): (own calculations, /ECOSTAR 2005/)

- Heliostats from 1.335 €$_{05}$/kW to 977-1.070 €$_{05}$/kW
- Power block from 890 €$_{05}$/kW to 583-760 €$_{05}$/kW
- Receiver from 556 €$_{05}$/kW to 239-395 €$_{05}$/kW

	/ECOSTAR 2005/ Initial cost [€$_{05}$/kW]	Reduction due to R&D [%]	Reduction due to mass-production [%]	Total Reduction [%]	/ECOSTAR 2005/ Final cost [€$_{05}$/kW]
Heliostat	1.335	15 - 22	5	20 - 26	977 - 1.070
Power Block	890	7 - 27	7,5	15 - 34	583 – 760
Receiver cost	556	22 - 50	7	29 - 47	293 – 395
Other components	927	-	-	-	927
Total	3.708	10 - 22	5	15 - 26	2.726 - 3.152

Fig. 3-18 Summary of costs reduction according to own calculations and /ECOSTAR 2005/

As it can be seen in the previous figure, the solar tower which is more likely to be constructed is a Solar Tres-type plant, which should be built around 2007 in Spain. It is expected that such a plant will have a cost of about 3.708 €$_{05}$/kW for a 17 MW_{el} plant and 2.726 - 3.152 €$_{05}$/kW for a 50 MW_{el} one (own calculations, /ECOSTAR 2005/). Concerning a near-term (2010) perspective too, the /S&L 2003/ study estimates that the costs for a

100 MW_{el} plant with 13 hours storage will drop to about 3.060 $US\$_{2003}$/kW. However, the cost for a plant to be constructed in 2006 in the USA is estimated to be very high.

3.3.2 O&M costs

The /S&L 2003/ O&M estimate is based on the actual costs from SEGS, whose operation is similar to that required for a solar tower's field and technology (mirror washing, mirror breakage, etc.). Some adjustments have been of course made, since for example in the solar tower the HCE is a single central receiver and not a series of tube with a much higher risk of failure. Obviously, the plant capacity increases directly as a result of the increases in thermal storage. However, increasing the size (MW_{el}) and utilization (capacity factor) of the power plant results in very little increase in O&M expenses ($/year). This is because the quantity and complexity of the equipment remain constant and staffing remains fairly constant.

Generally speaking, there are significant O&M cost improvements from increases in solar system efficiency, which reduces the solar field size. /S&L 2003/ has made a review of conventional fossil power plants, showing this "economy of scale" in staffing for increases in plant size.

The O&M costs are made up of staff, service & material and miscellaneous costs. The staffing was determined to be reasonable based on the following evaluation:

- The administrative staff would be the same for the increased plant size.
- The increase in plant size from 50 MW_{el} to 220 MW_{el} will not require additional operations or maintenance staff for operation and maintenance of the power plant. The difference between 50 and 220 MW_{el} does not increase the quantity or complexity of the equipment.
- The increase in the solar field maintenance staff, including mirror wash crew, is required to support the increase in the solar field. For Kramer Junction, approximately 0,03 maintenance staff is required per 1,000 m^2 of solar field aperture area.

Service & material include: service contracts, raw water and chemicals, parts and material and capital equipment costs.

The service contracts include typical contracts and costs expected for this type of facility, including control computers, office equipment, waste disposal, road maintenance and vehicle maintenance. Water and chemical usage for the power plant thermal cycle is consistent with industry averages for power plants. Parts and material costs for the conventional power plant are about 0.4 % of the capital cost, depending on the age and type of facility. /S&L 2003/ used 0.7 % of the capital cost for parts and materials related to the power block (turbine substitution) and balance of plant (mirror breakage and other failures), since in contrast to the SEGS trough plants the technology is relatively new and no operational experience has been gained yet. Capital equipment covers the equipment required to operate and maintain the facility (including dump truck, operator vehicles, mirror washing equipment, and tractor).

Miscellaneous costs include administration costs (such as safety, training, travel, supplies, and telephones) and vehicles fuel and repair. /S&L 2003/ projected increases for vehicle and fuel to account for the larger number of vehicles needed to support maintenance of the larger collector fields.

The O&M costs' summary, according to /S&L 2003/, based on the Solar One/Two plant experience between 1987-1999, is shown below (**Fig 3-19**):

O&M Characteristics	Solar One/Two 1987-1999	Solar Tres Near-term	100 MW_{el} 2008	220 MW_{el} 2020
Number of Staff	35	33	46	67
Staff Cost [$\$_{2003}$k/yr]	2.485	2.046	2.299	3.364
Annual Material & Services Cost [$\$_{2003}$k/yr]	750	686	2.065	4.277
Miscellaneous [$\$_{2003}$k/yr]	-	309	761	1491
Total O&M cost [$\$_{2003}$k/yr]	3.235	3.041	5.125	9.132
Capital cost [Mio $\$_{2003}$]	59	100	310	500
Fraction of capital costs [%]	5,4	3	1,6	1,8

Fig. 3-19 Summary of O&M costs /S&L 2003/, /SANDIA 2000/

As can be seen above, a realistic value for the O&M expenses for the near-term is about 3 % of the capital cost. Future plant operation will obviously result in a costs´ decrease. The Solar One/Two experience, since the first one of its kind, had of course higher O&M costs because of the many problems encountered in the first phase of its operation.

3.4 Solar dish

In order to make an economical evaluation of the solar dish systems, we will consider the experience of the two projects EURODISH and HYPHIRE that have been carried out on the Plataforma Solar de Almeria, since they provide economical data. We will consider at first the experience of the EURODISH project, which aimed at testing a new Dish/Stirling system in solar only conditions. Two of the seven 10 kW_{el} EURODISH systems have been operated on the PSA, bringing the total number of this type of system to seven. The other five dishes are currently in operation in the following countries: Spain, Italy, France, Germany (Würzburg) and India. This actual dish/Stirling design, operated in solar–only mode, can have a cost of about 11.000 €/kW_{el} for a single prototype installation /European Research 2004/.

EURODISH aimed to reduce the cost to about 5.000 €/kW_{el} for a production level of 100 to 500 units per year (1 to 5 MW_{el}). The evaluation carried out on the PSA found that this target will be almost reached, but only if a production of 500 units per year takes place /European Research 2004/.

However, in order to allow a market exploitation of the EURODISH design, the energy demand must be satisfied beyond sunshine hours, therefore an hybrid operation is required. This was the purpose of the HYPHIRE project, also carried out on the PSA. It is a twin-project of EURODISH, since it used the same design. The only difference is the hybrid operation mode, in order to solve the problem of continuous electricity production without the use of thermal storage, which is not a convenient solution for this technology. In fact the presence of the Stirling engine allows an easy coupling with a fossil fuel source, a solution much cheaper than a thermal storage. The HYPHIRE project has been assessed in detail by the /ECOSTAR 2005/ study, as shown in the following paragraph /European research 2004/, /ECOSTAR 2005/.

3.4.1 Investment costs

The most important elements which prevented the market expansion of the dish/stirling systems are the dish cost and the lack of a Stirling engine industry. There is so far only one company (SOLO, Germany) that started a small series production of Stirling engines, in this case not even for solar but for co-generation applications. Therefore it has made clear that the most important cost drivers for the solar dish are the Stirling engine, i.e. the element which absorbs and transforms the concentrated solar energy and the paraboloidal concentrator itself, which can be strongly affected by mass production. As explained in the introduction, there isn´t any thermal storage. This can be seen in the following picture (**Fig. 3-20**):

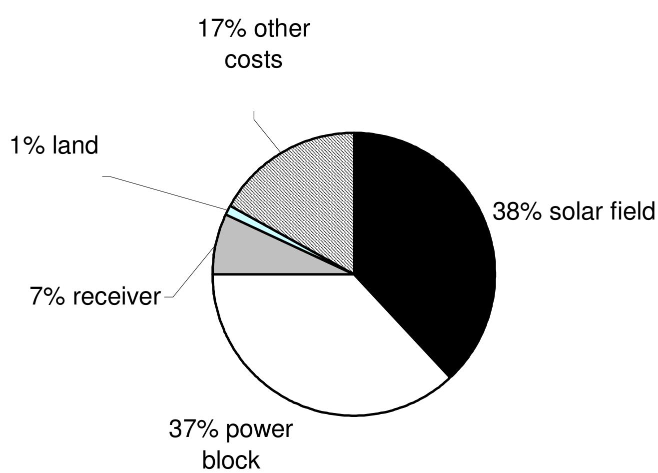

Fig. 3-20 Investment costs' breakdown of a 50 MW_{el} solar dish plant (own calculations, /ECOSTAR 2005/)

In the following figure (**Fig. 3-21**) the main cost drivers (solar field, power field, receiver) of the baseline case, which will achieve a cost reduction, are listed:

EURODISH 50 MW_{el} Baseline-components cost [$€_{05}$/kW]	
Solar field	3.053
Power Block	2.973
Receiver	562
Other costs	1.447
Total	8.035

Fig. 3-21 List of the main cost drivers /ECOSTAR 2005/

Since the total power output of the two dishes on the PSA is 20 kW_{el}, the /ECOSTAR 2005/ study assessed a plant with many of these systems (2.900). Coupled with a fossil fuel source, it allows a total output of 50 MW_{el}. The specific investment costs in this baseline-case would be 8.035 $€_{05}$/kW. However, even though the assessment simulated the presence of such a big number of single units, the mass production effect was not considered in this baseline-case, since has not yet taken place. For this reason this effect is treated as innovation (future cost-reducing factor).

Apart from mass-production, as seen in the previous chapters there is also another main way to achieve future cost reductions: R&D. This will however considered later on, since the huge amount of single units needed to reach the design output of 50 MW_{el} clearly indicates that the greatest impact comes from effective mass production. This should bring down the specific costs per installed power to about 5.278 $€_{05}$/kW, as can be seen in the following figure (**Fig. 3-22**):

EURODISH 50 MW_{el} components' costs [$€_{05}$/kW]	
Solar field	1.750
Power Block	1.750
Receiver	331
Other costs	1.447
Total	5.278

Fig. 3-22 Components' costs after mass production (2.900 units) (own calculation, /ECOSTAR 2005/)

On the other side, if together with mass-production we also consider the effect of R&D innovations, the dish/Stirling system should be able to reach an installed cost of around 3.565 $€_{05}$/kW (**Fig. 3-23**):

EURODISH 50 MW_{el} components' costs [$€_{05}$/kW]	
Solar field	1.278
Power Block	600
Receiver	240
Other costs	1.447
Total	3.565

Fig. 3-23 Components' costs after mass-production and R&D innovations (own calculations, /ECOSTAR 2005/)

However, this is considered achievable by using a gas turbine (Brayton cycle) instead of the Stirling engine, which is a major breakthrough and has not been tested yet. Other innovations considered by the /ECOSTAR 2005/ study are: improved availability, increased engine efficiency, lower engine cost, increased mirror reflectivity and tracking accuracy, increased dish size and improved availability.

3.4.2 O&M costs

It's particularly difficult to make a prevision of O&M costs for the solar dish, since no large-scale plant using this kind of technology has been ever constructed. The only data available are those from the extensive test program carried out on the PSA by the project EURODISH and HYPHIRE, which however assessed only two dish/Stirling system.

Previsions have been however made by the /ECOSTAR 2005/ study, which assessed a simulated 50 MW_{el} plant. Without considering the administration costs, the study found that a hybrid operation of such a plant would have an O&M cost of 11.451 $€_{2005}$/yr, which is about 2,8 % of the total capital costs (around 400 Mio $€_{2005}$) /ECOSTAR 2005/.

The plant would require 30 persons, of which 21 are required for the solar field maintenance and 9 for the power block. The labor cost of the employee is about 48.000 $€_{05}$/yr /ECOSTAR 2005/.

3.5 Summary

In the previous paragraphs the costs of the different CSP systems have been shown. The results will now be summarised, following the usual order: parabolic trough, tower, solar dish.

It will be distinguished between investment costs and O&M costs. We will begin with the most important of them, the investment costs.

In all of the CSP concepts the solar-specific equipment, i.e. the components which have the task of collecting the solar energy, has been found to be the most expensive ones. Therefore the cost reduction potential has been assessed in the previous paragraph referring only to this equipment, which is also the most sensible to cost-reduction measures.

Concerning the parabolic trough, it must be remembered that the investment cost previsions are based on the commercial SEGS plants (365 MW_{el}, no storage), successfully operating since 1989 in California, which had a cost of 3.947 $US\$_{2005}$/kW. For near and long term specific investment costs previsions, the following figure (**Fig 3-24**) shows a comparison between the two main sources used in the analysis: /S&L 2003/ and /ECOSTAR 2005/.

Plant type	Near-term plant	Near-term plant	Future plant	Future plant
Year of construction	2004	2005	2020	2020
Power	50 MW_{el}	50 MW_{el}	400 MW_{el}	50 MW_{el}
Storage	12 hours	3 hours	12 hours	3 hours
Capital costs	4.816 $US\$_{2003}$/kW	4.200 $€_{05}$/kW	2.400 $US\$_{2003}$/kW	2.940 $€_{05}$/kW
Source	/S&L 2003/	/ECOSTAR 2005/	/S&L 2003/	/ECOSTAR 2005/

Fig. 3-24 Comparison between actual and expected investment costs of parabolic trough plants /S&L 2003/, /ECOSTAR 2005/ (cf. **Fig. 3-8**)

From the previous figure it can be seen that /S&L 2003/ expects a future cost reduction of 50 %, while /ECOSTAR 2005/ a reduction of 30 %.

Concerning the solar tower, it must be remembered that no commercial plants have been built since 2005. Therefore the reference case is represented by the demonstration plant Solar Two (U.S.A.). Solar Two has been the basis for Solar Tres, the first commercial tower, which is to be built in Spain. As for the parabolic trough, the investment costs prevision has been made referring to the American source /S&L 2003/ and the European /ECOSTAR 2005/, as the next figure (**Fig 3-25**) shows:

Plant type	Solar Two	Solar Tres USA	Solar Tres Spain	Solar Tres Spain	Near-term plant
Year of construction	1996	2004	2007	2007	2010
Power	10 MW_{el}	14 MW_{el}	17 MW_{el}	50 MW_{el}	100 MW_{el}
Storage	4 hours	16 hours	16 hours	16 hours	13 hours
Capital costs	5.570 $US\$_{2003}$/kW	7.100 $US\$_{2003}$/kW	3.708 $€_{05}$/kW	2.726 - 3.152 $€_{05}$/kW	3.060 $US\$_{2003}$/kW
Source	/SANDIA 1996/	/S&L 2003/	/ECOSTAR 2005/	/ECOSTAR 2005/	/S&L 2003/

Fig. 3-25 Investment costs' evolution from Solar Two to near-term plants (own calculations, /SANDIA 1996/, /S&L 2003/, /ECOSTAR 2005/) (cf.**3-10**)

The cost reduction shown above is as usual achieved through mass-production and R&D.

The economical evaluation of solar dish system has been performed according to the /ECOSTAR 2005/ study, which refers to the European project HYPHIRE, a hybrid operation of the EURODISH dish/Stirling design. In this project, two 10 kW_{el} dish/Stirling systems have been tested. The Australian concept of the dish-farm plant has not been assessed. The investment costs of the considered system, a series of 2.900 dishes, each one with 10 kW_{el} power output with fossil backup, is shown below (**Fig. 3-26**). The initial cost refers to the two systems effectively tested, the final one is a estimate of the cost after R&D and scaling-up to 2.900 units. The fossil backup allows a power output of 50 MW_{el}.

	Initial capital cost (near-term expected cost)	Final capital cost (future plant)
/ECOSTAR 2005/	8.035 $€_{05}$/kW	3.565 $€_{05}$/kW

Fig. 3-26 Actual and near-term expected investment costs for a hybrid dish/Stirling system (own calculations, /ECOSTAR 2005/)

Concerning O&M costs, the following figure (**Fig. 3-27**) shows a summary of the different values found in the previous paragraphs for the CSP technologies, each time considering a near term construction. The investment costs for each technology are based on the near-term cases shown in the previous figures. The percentage of the O&M costs in relation to the related total investment costs together with other important data of the plants are also shown.

	Parabolic trough	Solar tower	Hybrid Dish/stirling
Plant characteristics	50 MW_{el}, 6 hours storage	17 MW_{el}, 16 hours storage	50 MW_{el}
Year of construction	Near-term	Near-term	Near-term
Economic Life	30 years	30 years	30 years
Total investment cost	210 Mio $€_{05}$ -241 Mio $US\$_{03}$	63 Mio $US\$_{03}$	400 Mio $€_{05}$
Specific Investment cost	4.200 $€_{05}$/kW – 4.816 $US\$_{03}$/kW (**Fig. 3-24**)	3.708 $€_{05}$/kW (**Fig. 3-25**)	8.035 $€_{05}$/kW (**Fig. 3-26**)
O&M costs	3.609 $k\$_{03}$/yr - 4.003 $k€_{05}$/yr /PRICE 2003/, /ECOSTAR 2005/	2.832 k $€_{05}$/yr / ECOSTAR 2005/	11.451 $k€_{05}$/yr /ECOSTAR 2005/
Fraction of O&M cost in relation to investment cost [%]	≅ 1,5 –1,7	≅ 4,5	≅ 2,8
Full Load Hours per year	2.737 h /Aringhoff 2005/	2.190 h /EnergieSchweiz 2004/	2.190 h /NET Switzerland 2003/

Fig. 3-27 Comparison of CSP plants to be built in the near-term

From the previous figure it can be seen that, concerning the specific investment costs, the parabolic trough if the most convenient CSP system. However the figures can vary substantially with the number of Full Load Hours per year. Realistic values have been chosen for this parameter, even though they could appear too conservative if compared with those provided from some industrial actors. The long commercial experience undergone by the parabolic trough results in a higher number of Full Load Hours for this kind of CSP system.

3.3 LEC

Power plants are most frequently compared on the basis of their Levelised Electricity Costs (LEC), which relates the capital cost of the plant, its annual operating and maintenance costs to the annual production of electricity.

The levelized electricity costs are calculated as follows:

$$\text{LEC} = \frac{(CC \cdot AF) + O\,\&\,M + Fuel}{A}$$

Whereby:

- CC = total capital cost
- AF = annuity factor
- O&M = annual operating and maintenance expenditure including taxes and insurance
- A = annual net electricity generation in kWh
- Fuel = fuel costs for hybrid operation

Some assumptions are of course necessary. An interest rate of 6 % has been assumed, therefore the factor q is:

$$q = 1{,}06$$

Then the annuity factor is:

$$\text{AF} = \frac{q^D \cdot (q-1)}{(q^D - 1)} = 0{,}0726$$

whereby D is the economical life of the plant. For all the CSP systems considered the plant's life is D = 30 years, therefore AF is the same for all the systems considered.

The annual net electricity generation has been calculated on the basis of the expected full load hours per year and the design power output:

$$A = \text{Full Load Hours [h/a]} \times \text{Power Output [kW]}$$

The following figures show the projected LEC for a near-term plant (whose data have been shown in **Fig. 3-27**) and for future installations for the different CSP systems. In all the cases for the O&M costs an assumption of 3 % of the capital cost has been made, even though past plant operations (e.g. parabolic trough) have shown that smaller values could be possible. **Fig. 3-28** shows the LEC for parabolic trough, whose data for near-term and for future plants have been shown in **Fig. 3-24**:

	Near-term plant	Future Plant
Power Output	50 MW_{el}	50 MW_{el}
Year of construction	Near-term	Middle-term
Economic Life	30 years	30 years
Specific Investment cost	4.200 $€_{05}$/kW	2.940 $€_{05}$/kW
O&M costs [%] (fraction of the total capital costs)	3	3
Full Load Hours [h/a]	2.737	2.737
A (Annual generation) [GWh/a]	136,85	136,85
LEC [$€_{05}$/kWh]	0,158	0,110

Fig. 3-28 LEC for actual and future parabolic trough plants (cp. **Fig. 3-25**)

The following picture (**Fig. 3-29**) shows a variation of LEC costs after varying the different input parameters, while leaving the others constant. The baseline which will be subjected to variations is the near-term case shown in the previous figure, therefore “100 %” is related in the next figure to a LEC of 0,15 $€_{05}$/kWh. The inputs are the specific investment costs, the full load hours, the economic life, the interest rate and the O&M costs. It can be clearly seen that the LEC are particularly influenced by variation of the full load hours and the specific investment cost, whilst the other entities play a minor role:

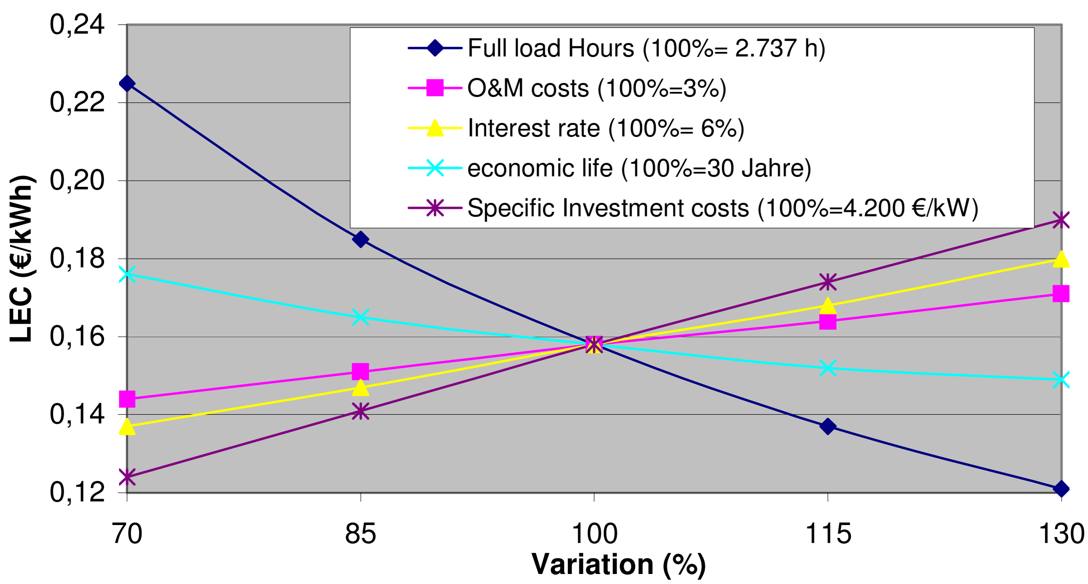

Fig. 3-29 Analysis of LEC sensibility to each of the inputs considered for the trough system

The same procedure has been applied for the solar tower. **Fig. 3-30** shows the LEC for this type of CSP, while **Fig. 3-31** shows each variation of LEC costs after varying the different input parameters, while leaving the others constant. The baseline which will be subjected to variations is the Spanish near-term case shown in **Fig. 3-25**, therefore "100 %" is related in the next figure to a LEC of 0,174 €$_{05}$/kWh. The inputs are the same considered for the parabolic trough. It can be clearly seen that the LEC are particularly influenced by variations of the full load hours and the specific investment cost, whilst the other entities play a minor role:

	Near-term plant	Future Plant
Power Output	17 MW_{el}	100 MW_{el}
Year of construction	Near-term	Middle-term
Economic Life	30 years	30 years
Specific Investment cost	3.708 €$_{05}$/kW	3.060 US$$_{03}$/kW
O&M costs [%] (% of the total capital cost)	3	3
Full Load Hours [h/a]	2.190	2.190
A (annual generation) [GWh/a]	30,66	219
LEC	0,174 €$_{05}$/kWh	0,143 US$$_{03}$/kWh

Fig. 3-30 LEC for actual and future solar tower plants (cp. Fig. **3-25**)

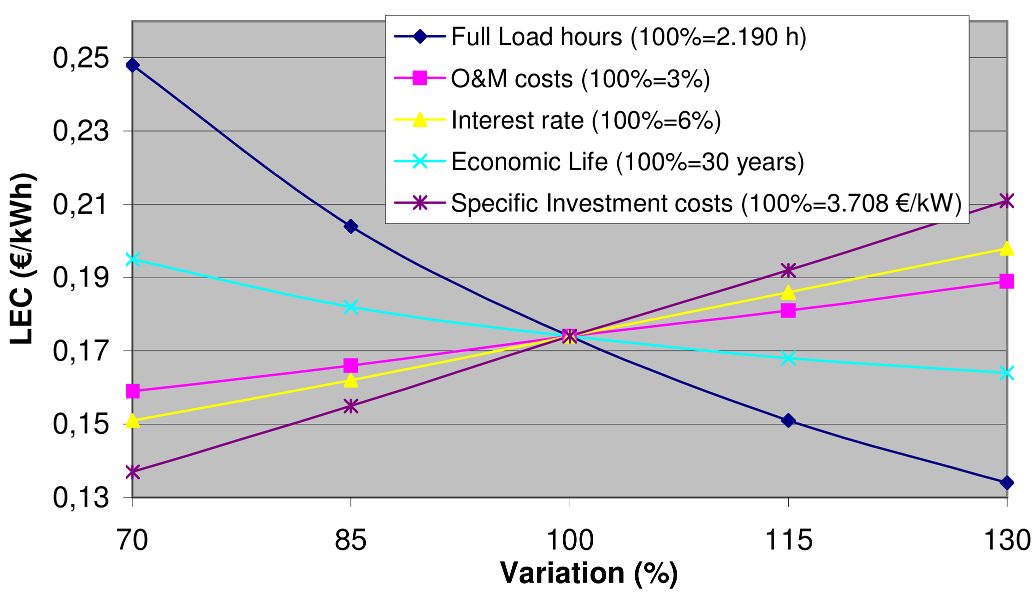

Fig. 3-31 Analysis of LEC sensibility to each of the inputs considered for the tower system

Concerning the solar dish, the main difference with the other CSP systems analysed is that only a hybrid operation has been considered, therefore the input "fuel" has to be added to the previous ones. According to /ECOSTAR 2005/, a baseline cost of 0,015 €/kWh the fuel has been chosen.

Fig. 3-32 shows the LEC for the solar dish, while **Fig. 3-33** shows each variation of LEC costs after varying the different parameters, while leaving the others constant. Here, too, it can be clearly seen that the LEC are particularly influenced by variation of the full load hours and the specific investment cost, whilst the other entities play a minor role:

	Near-term plant	Future Plant
Power Output	50 MW_{el}	50 MW_{el}
Year of construction	Near-term	Middle-term
Economic Life	30 years	30 years
Specific Investment cost	8.035 $€_{05}$/kW	3.565 $€_{05}$/kW
O&M costs [%] (% of the total capital cost)	3	3
Full Load Hours [h/a]	2.190	2.190
A (annual generation) [GWh/a]	109,5	109,5
LEC [$€_{05}$/kWh]	0,392	0,182

Fig. 3-32 LEC for actual and future solar dish plants (cp. Fig. **3-26**)

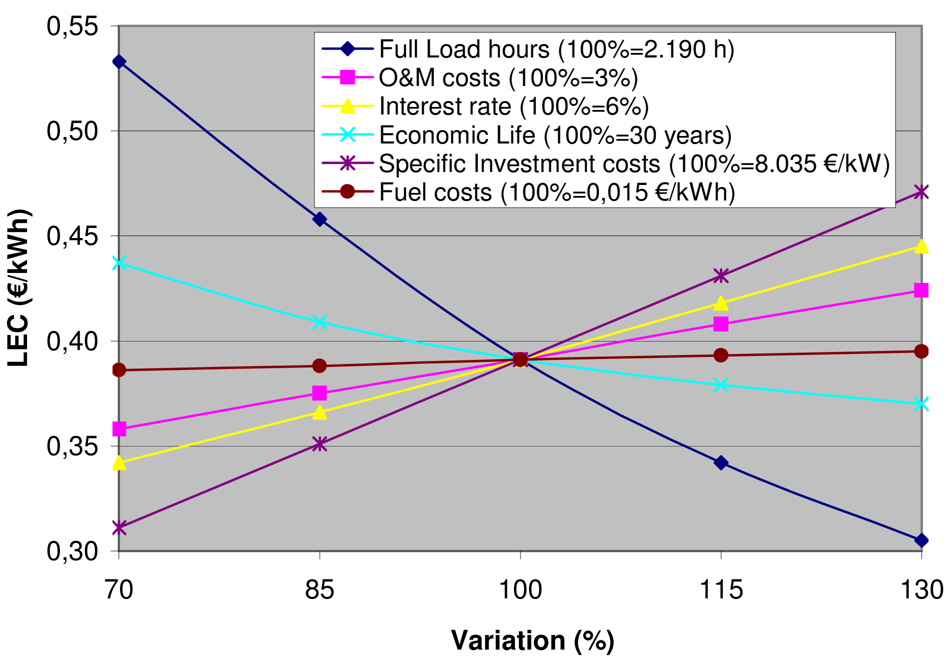

Fig. 3-33 Analysis of LEC sensibility to each of the inputs considered for the solar dish system

As shown above, the small size of the plants and the pure solar design for most of them make necessary the existence of a public economical support through investment subsidies (both

European and National) and a special tariff for the electricity produced. The Spanish ROYAL DECREE 2818/1998 of December 23 1998, on the electricity production by facilities powered by renewable energy sources offered a green price of 0.18 €$_{05}$/kWh for the electricity generated by CSP plants (with a maximum size 50 MW_{el}) that opened a unique opportunity to start the market introduction of solar thermal power plant technology under commercial conditions /EuroEnergy 2001/.

On March 27th, 2004, the ROYAL DECREE 436/2004 improved the incentives for the first 200 MW_{el} of solar thermal electricity production in Spain considerably.

The average electric tariff or "reference price" for the year 2004, defined in the Article 2 of Real Decreto 1432/2002 of December 27, has a value of 0,072 €$_{04}$/kWh. Solar thermal electricity generators who cede their production to the power distribution company may receive as fixed tariff 300 % of the reference price (i.e. 21,6216 €cent$_{05}$/kWh) during the first 25 years after their startup and 80 % of that value afterwards. Solar thermal electricity generators who sell their electricity on the free market may receive as premium 250 % of the reference price (i.e. 18,018 €cent$_{05}$/kWh) during the first 25 years after their startup and 200 % afterwards plus an incentive of 10 % (i.e. 0,72072 €cent$_{05}$/kWh) /SolarPaces 2005/, /Nava 2004/.

This decree also quantifies the utilization of gas for auxiliary firing: the installations, which utilize as primary energy for the generation of electricity the solar thermal energy, may use auxiliary equipments which consume natural gas or propane only for maintaining the temperature of the heat storage. The consumption of said fuel, in annual computation, must be inferior to 12 % of the electricity production and only during the periods of interruption of the electricity generation, if the installation cedes the electricity to the power distribution company at fixed tariff. This percentage may reach 15 %, without time restrictions of use (but only to maintain the temperature of the storage), if the installation sells its electricity freely in the market /SolarPaces 2005/.

From these considerations and from the LEC calculations performed above, it's clear that constructing a parabolic trough plant, like Andasol in Spain (0,158 €$_{05}$/kWh), can be remunerative.

Concerning the solar tower, if we consider the previsions made by /S&L 2003/, which have officially assessed the Solar Two experiment, a near-term plant can hardly be economically feasible (0,333 US\$$_{03}$/kWh). However, the big research work carried out on the PSA and assessed by the /ECOSTAR 2005/ study shows that substantial cost reduction are potentially possible for the first European solar tower to be built in Spain in 2007: PS10 (10 MW_{el} , 50 min storage), whose power generation will be too discontinuous to be considered as a reference for future installations, or Solar Tres (17 MW_{el}, 16 hours storage). For the first plant a LEC of about 0,164 €$_{05}$/kWh could be achieved, which means the incentives of the Spanish government could bring its operation to the threshold of the profit. The same considerations apply to Solar Tres, since the LEC would be similar (0,174 €$_{05}$/kWh).

The solar dish, even operated in hybrid mode, shows very high LEC (0,392 $€_{05}$/kWh) for near-term applications. The expected future LEC of 0,182 $€_{05}$/kWh will be possible only after a production of 500 dishes per year, which at present is rather unrealistic. Therefore its exploitation is not commercially feasible for large-scale power generation, while it represents on the contrary an interesting solution for off-grid applications, where fuel's supply can be difficult and fuel costs are rather high (0,60 €/kWh), like in developing countries.

4 Italian CSP

Despite the favourable environmental condition which could have prompted Italy in a leading position in the field of CSP, the lack of political will coupled with some unsuccessful decision in matter energy policy, only in the last years the CSP systems seem to have awakened a new interest among private and public investors. At present there are two projects which are likely to successfully enter their operative phase:

- The parabolic trough in Priolo Gargallo (Siracusa), whose development required the planning of a pre-industrial facility in Specchia (Lecce).
- The two solar towers of the new Hospital of Empoli.

4.1 The Parabolic troughs in Priolo Gargallo and Specchia

The parabolic trough power plant of Priolo Gargallo, whose construction has begun on 2004, is an ISCC (Integrated Solar Combined Cycle), which means it's coupled to a conventional gas and steam cogeneration plant, providing an expected extra-output of 20 MW_{el} to the 760 MW_{el} that it's already delivering. The project is called ARCHIMEDE and it's a joint-venture between the main partner, the public research institute ENEA, and the national energy company ENEL. They are working together with many other minor private companies. The schema of the ISCC system is pictured below (**Fig 4.1**):

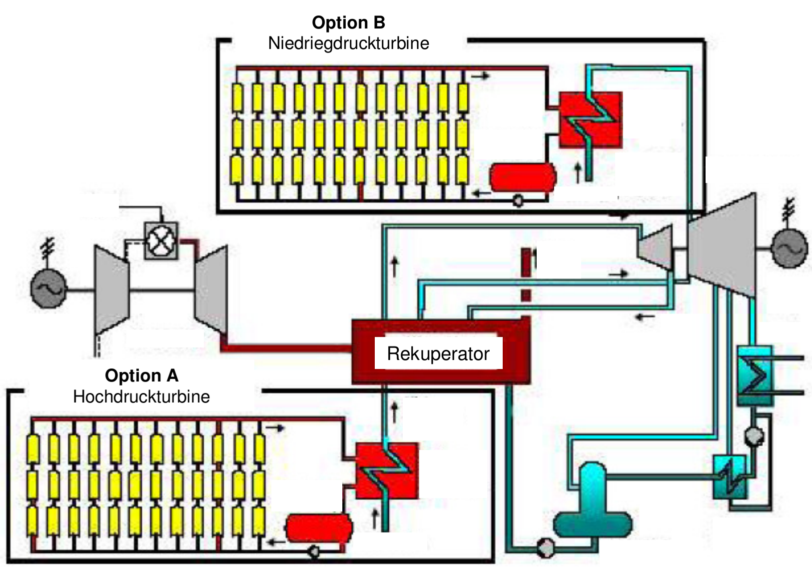

Fig. 4-1 Schema of an Integrated Solar Combined Cycle /Stine & Geyer/

The main advantage of the hybrid solution is that the solar plant will make large use of the already existing non-solar components, therefore focusing the investment costs on the solar-technology elements. Moreover, the electricity generation can be adjusted in order to match peak-demands during the day.

Other new improvements are:

- A cheaper and more robust mirror design.
- A higher operating temperature, which is now about 550 °C, which requires, in turn, a new design of the coating of the layer receiving the concentrated solar light.
- The use of an environmentally friendly, non-flammable cooling liquid.
- The introduction of a large heat storage, which can fully compensate for solar discontinuities.

We'll describe these elements more precisely, referring to /ENEA 2004/ as source.

The mirror are extremely rigid honeycomb panels of 2,5 cm thickness with an Aluminium core and Steel skins, on whose inner surface a thin glass mirror is glued. The collecting tube is made of a coaxial structure of an external glass tube of 11,6 cm diameter and of a steel tube of 7 cm diameter, inside which flows the cooling liquid in the form of a molten salt. A suitable coating on the steel tube has been also specifically developed by ENEA for its plant.

In SEGS plants the cooling liquid is a mineral oil, flammable and toxic. The properties of this liquid limit the operating temperature of the plant and — because of safety and cost — do not permit the accumulation of the hot liquid to the extent needed for effective energy storage. Therefore in the ENEA project a molten salt, an eutectic nitrates mixture was chosen. This low cost salt is widely used as a fertilizer and it is cheap and readily available in very large quantities. It is operated in the temperature interval between 290 °C and 550 °C: such choice of temperature is dictated by the fact that at about 600 °C the nitrates decompose partially into nitrites, which may represent a problem with corrosion. The development of the various components related to such a large implantation with molten salt has been completed and many potential problems, like for instance the one due to corrosion and to accidental freezing of the coolant, have been fully tested with satisfactory results.

A big issue is of course the thermal storage. The heat capacity is enhanced by the large temperature difference (275 °C) between the hot and cold liquids /ENEA 2004/. In simple terms, storing 1 kW_{th} requires about 4,9 litres of molten salt. The energy accumulated in a given volume of molten salt is equivalent to the one of the combustion of the same volume of natural gas. However while the refilling of a natural-gas tank is normally performed with a periodicity of months, the accumulation time necessary for the heat storage is defined by the daily cycle, eventually extended in order to take into account of a few cloudy days. Therefore the dimensions of the fuel tank and of the heat storage for a given power installation are of comparable sizes. For example, in order to smooth out the daily Sahara solar energy in the month of July from 1 km^2 of collectors into a constant, around the clock delivery of about 300 MW_{el} of electric power, the required tank is a cylinder about 30 m in diameter and about 21 m tall. ENEA expects the thermal losses for its heat storage tank to be of reasonable proportions, i.e. of less than 1 % loss per day. This efficient storage process is similar to the one used for the solar tower technology, since the molten salt flows into a "hot tank" first, then into a heat-exchanger which will generate water-steam for the turbine. After that, it will be sent to a “cold tank” and again in the cycle /ENEA 2003/. The scheme is pictured below (**Fig. 4-2**):

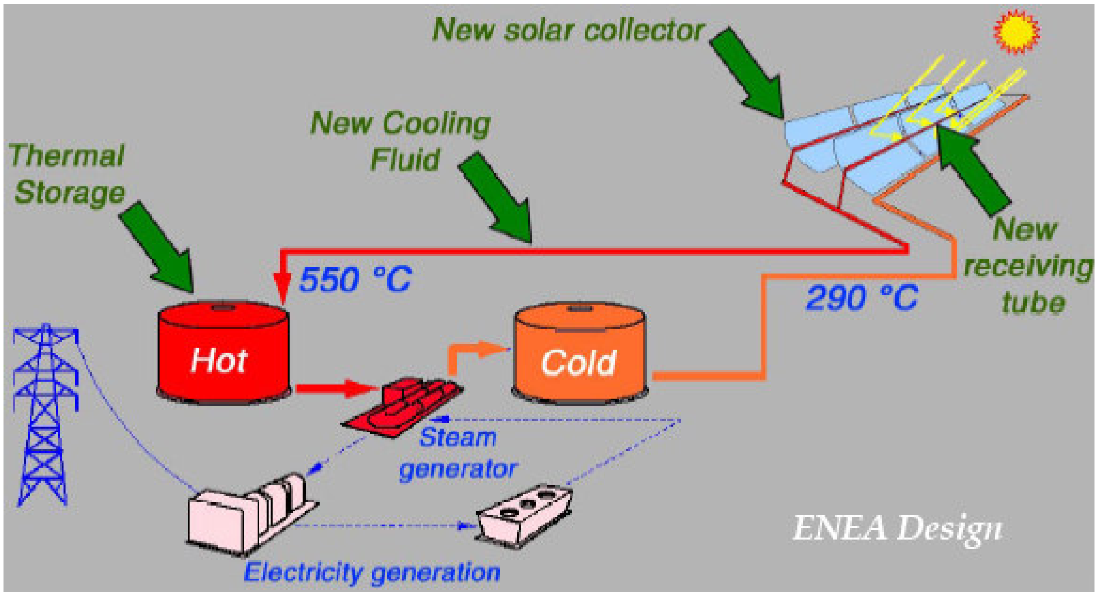

Fig. 4-2 Storage system /ENEA 2004/

The system uses different heat transfer fluids for the solar field and for storage. It has a unit cost of \$30-\$40/kW$_{th}$, mostly due to the heat-exchanger. To reduce the unit cost to below \$10/kW$_{th}$, American researchers are trying to develop single-tank storage system and heat transfer fluids that can be used in both the solar field and in the storage system /NREL 2005/.

However the two-tank system has surely been long tested and the ENEA researchers don’t have taken into consideration the idea of pursuing a single-tank concept, which seems to be the long-term solution for future plants like the solar tower Solar Tres.

ENEA didn’t start a wide-spread collaboration with the major European CSP actors, having developed by itself the solar key-components, which already exist and have been tested for a long time but had to be modified in order to match the new operational conditions. The experience gained from the solar tower in Adrano (now a PV plant) proved to be extremely useful, since the heat-transfer medium typical for this high-temperature technology (a mixture of molten salts) has been tested there for a long time and it will be now successfully used in the parabolic trough, making possible reaching the temperatures mentioned above. This solution brings together the positive aspects of both the most promising CSP technology, the parabolic trough and the solar tower, allowing to overcome their natural limits. What is in fact expected in Priolo is basically to improve the overall efficiency in order to make the plant competitive despite its small size, which is usually the biggest handicap for the economical profitability of a parabolic trough. To reach this ambitious target, since the beginning of 2001, a vigorous R&D programme has been initiated (15 million euro spent only in 2002).

However, the long term target is the realization of a solar-only generation plant. A program for a plant of this type connected to the Italian electric grid has been launched jointly with the Regional Government of Puglia and other private partners. The present Italian market of "green" electricity is allows the operation of such a plant to be financially supported by its electricity production. A commercial demonstration plant of 0,5 km^2 size is expected to be fully operational in Specchia (Puglia) by 2006. It will have a power output of 12 MW_{el} and a thermal storage of 600 MW_{th} (about 12 hours of electrical energy output).

Other demonstration plants are under consideration and it is reasonable to expect a fully commercial product ready for large-scale deployment before 2007. They are intended to facilitate the development of a modular solar collection unit with 250 MW_{th} peak thermal power and adequate thermal energy storage, capable of continuous electricity production of about 40 MW_{el}. Up to ten of these units (400 MW_{el}) can be clustered with common conventional electricity generation facility. They are intended primarily as dedicated units for electricity supply to the grid, from a favourably "sunny" location. As found by DLR and other studies, the Sahara desert would be an ideal place from which to connect for instance to the European electricity network /ECOSTAR 2005/.

The second major long-term target is the development of a stand-alone solar collection unit of about 60 MW_{th} peak thermal power equipped with a thermal energy storage, capable of ensuring a time-averaged, electricity production of about 10 MW_{el}. As in the previous case, several of these nearby solar fields could share a common conventional electricity generating facility. These units are best suited to provide electricity to off-the-grid locations. They are an interesting product for instance for sunny islands and for remote regions, especially in sun rich developing countries. Typically one of these plants could provide the continuous supply of the basic electricity needs to a community of some 20.000 to 100.000 people. Both products, which can be custom tailored to a large variety of ground configurations and specific needs, rely on a common modular design of the solar collector and of the heat collecting, molten salt system. The specific unit cost of the solar collection devices, estimated to be the same of conventional plants in 2020, is practically the same in both configurations and will decrease due to scaling-up effects /ENEA 2003/.

The results expected for 2005 are: the completion of the first experiment campaign at the Prototipo Collettore Solare (PCS) test facilty in Casaccia (PU), the beginning of a second series of tests on new receivers, mirrors, junctions and supporting structures, the serial production of the receiver and the installation and operation of a new "sputtering machine" for mirrors cleaning /ENEA 2004/.

4.2 The solar towers of the new Hospital of Empoli

The other important Italian CSP project is the solar tower power plant presently being built in Empoli, which is benefiting from a special rate for combined heat and power and from additional subsidies, namely a 50 % contribution from regione toscana to the total investment, quantified in 2 millions euro. The two towers will use pressurised 250 kW_{th} central receivers (designed by DLR), which will supply two 80 kW_{el} gas turbines with hot air for electricity generation, combined with heating and air conditioning systems. Each tower will have an heliostats´ field of 19 units, as can be seen in the picture below (**Fig. 4-3**):

Fig 4-3 One of the heliostat field in Empoli /ForumEnergia 2004/

The heliostats, each one with a surface of 25 m^2, will be able to achieve on the receiver a temperature of about 750 °C /Officina Italia 2005/. The hybrid solution has been studied 20 years long by the major partners of the project: DLR, the Weizmann Institute and the Tel Aviv University. Heat and conditioning will be achieved simultaneously by using absorption boilers, an invention patented by A. Einstein.

The project has rather R&D character, however it is used to provide the new city hospital with all its energy demands (electricity, heat and conditioning), one of his main objective being also selling the exceeding electrical power to the national energy company ENEL. According to the main Italian partner ESCO Solar, an energy consulting company, thanks to the plant the hospital will spare 20 % of the fuel used (natural gas), saving nearly 3 Mio euro per year /Tuscany Valley 2005/. The plant should become operative already at the end of 2005, but the idea is to extend this concept to other hospitals and big public structure in Tuscany. A project for the construction of solar towers similar to those in Empoli has been presented to the Council of regione sicilia by the private company SHAP S.p.a. and is at present under evaluation.

4.3 CESI´s Solar Dish

Since 2002, a EuroDish-type dish/Stirling solar generator (56 m^2, 8,5 m diameter) has been erected, connected to the public grid, and operated in Milan at the CESI, the Italian Electrotechnical Experimental Center. The other project partners are the German engineering companies SBP (Schlaich Bergermann und Partner) and MERO International GmbH & Co.

The operation continued during 2004 with progressive improvement in performance. Some modifications in the external cavity and the cooling circuit improved operating stability and efficiencies , which is now about 15 % at 800 °C . Other minor modifications in electronics reduced the sensitivity of the system to grid disturbances. Since its construction, the generator has been operated only on workdays for more than 1500 hours, with an overall average power output of 3,54 kW_{el}. This is a good result considering the climate and latitude of Milan (45,5°). The average power increased from 3.4 kW_{el} in 2003 to 4.0 kW_{el} in 2004. The maximum power measured was 9 kW_{el} at 930 W/m², which is close to the values obtained with the same solar units installed at the Plataforma Solar de Almeria, even though the overall efficiency and availability of the generator unit suffered by the limitations of the cooling system to operate at the highest rates of power in coincidence of high ambient temperatures /SolarPaces 2005/.

During this first test period the Eurodish solar generator showed an overall good reliability and satisfying performances even in the unfavourable north Italy whether conditions. The reliability of the SOLO 161 (10 kW_{el}, 400 V, asynchronous) Stirling motor core resulted to be excellent as no troubles emerged during more than 800 hours of operation. Maintenance of the motor was negligible apart from some initial minor troubles. As expected, the periodical refilling of helium working gas resulted to be an easy and fast operation. The control software of the generator unit showed an overall good reliability even in case of the strong variability of the solar thermal input. Nevertheless some improvements in the control software and in the management of the grid failures are advisable to facilitate the operation of the Eurodish generator.

Due to a budget reduction in 2005, the generator will be operated from now on for demonstration only /SolarPaces 2005/.

4.4 Italian Energy Policy for Renewables

This summary is based on /Farinelli 2004/ and /IEA 2003/ as sources.

Until after World War II, renewable energy systems (RES) contributed very substantially to the energy budget of Italy. The bulk of electricity was produced by hydropower stations and firewood was used extensively for heating and cooking, particularly in the rural areas. Italy was also the first country in the world to exploit the geothermal energy source for producing electricity on a large scale.

The prospects changed completely with the post-War reconstruction. Very few new opportunities were available for hydropower plants to meet the rapidly increasing electricity demand; overexploitation of wood resources during the War had brought about deforestation; oil rapidly spread as the universal energy source, thanks in part to the dynamic policy of ENI, the national petroleum company. The energy crisis of 1973 brought back some interest in alternative energy sources, including renewables; however, the main change in the Italian energy system was the rapid growth of the role of natural gas, while the expansion of nuclear power and the revival of coal were blocked by public opposition and nothing much happened in the field of RES, even after the second oil crisis of 1979. In the 1990s, more interest was taken by the government and the public in RES because of environmental and climate preoccupations, together with the initiatives and the directives of the European Union, especially after the signing and ratification of the Kyoto Protocol. The commitment to double by 2010 the share of renewables in the Italian energy budget from the level in 1990 (from 7 % to 14 %), in parallel with the doubling at the EU level, will not be easy to meet.

4.4.1 Chronology of Italian public efforts for RES

Public funds for RES started in the late 1970s and were mostly directed to universities but also in some industries and research centres. Since 1982 most R&D on RES was carried out by ENEA, the Italian National Agency for New Technologies, Energy and the Environment. The level of spending on RES' R&D was relatively high in these years, because the funds of former expensive nuclear activities that were being phased out were now available, and comparable to R&D investments in other European countries; in the 1990s the funds for RES R&D gradually decreased and are now at a historical minimum. The total government spending for energy R&D in 2001 was 188.5 Mio euro (as compared with 412.5 Mio euro in 1990). Of these, the amount devoted to renewable energy decreased from 31.9 Mio euro in 1990 to 24.8 Mio euro in 2001. The total budget 2001-2003 of ENEA was approximately 95 Mio $ /SolarPaces 2001/. The scope of R&D involved in those years practically all RES, but the two sources that have received most attention are solar photovoltaic and biomass.

In the 1980s, the government could act through the public monopolies: ENEL for electricity and ENI for oil and gas. In terms of RES there wasn't any significant activity; ENEL and ENI were committed to their core business, with little interest in expanding their field of action. ENEL built EURELIOS, the 1 MW_{el} central tower solar thermodynamic demonstration plant in Adrano (Sicily), which proved to be a failure. Private industry did not fare much better. The banking system in Italy, usually rather conservative, has certainly not pushed for the development of RES, and cases of successful project financing are not common. One of them was the project of the pre-commercial trough plant in Priolo Gargallo (cf. **4.1**), which managed to get bank financing but in the last months has been almost abandoned by the Government and ENEA.

As in many other countries, energy policy in Italy has progressively changed from direct government involvement to liberalisation and market-oriented mechanisms. This evolution applies as well to RES. From 1980 to 1995 the energy supply sector was mostly in the hands of the two public monopolies, ENI and ENEL and it was only by the end of this period that the concepts of energy market, liberalisation and privatisation started being introduced. In 1992 the government decided (with the CIP 6/92 Act /Farinelli 2004/) that ENEL must buy and transmit on its grid all electricity produced by RES plants, paying for it incentivising prices, which were fixed by this decree in order to make electricity production from RES economically viable (for the producer) for a number of technologies (mostly wind, biomass and wastes) in a number of situations.

However, the instrument was considered too expensive, since the demands were very numerous and the decision fixed no ceiling; the extra costs were to be paid on the electricity bill and the effects on the consumers started being felt. However, the biggest problem was that it was applied not only to RES but also to "assimilated sources", like CHP plants, which multiplicated in those years. A ministerial decree in 1996 suspended the procedure. However, its impact on the diffusion of RES was substantial. After 1995 the liberalisation of the energy market as well as the privatisation of the former public monopolies for gas and electricity started. Market liberalisation seems not to favour RES: in general, they are less attractive economically for the producer, who has to keep costs as low as possible. ENI and ENEL in particular, which had been keeping up a certain level of ongoing activity on RES, have greatly reduced their efforts in this area.

In 2002, the government introduced a renewable energy obligation associated with green certificates to stimulate investments in electricity production from renewable energy sources. Since then, companies importing or generating electricity from non-renewable sources exceeding 100 GWh per annum are obliged to supply a minimum 2 % of their total electricity imports or generation from renewable energy sources. The obligation is planned to increase gradually to 2.7 % in 2006 and 3.05 % in 2007. Further increases are being discussed in Parliament. The renewable energy obligation does not distinguish between various renewable energy sources; the choice of source is left to operators based on market principles. This obligation can be fulfilled through the trading of green certificates between electricity producers using renewable sources of energy and importers or generators using conventional energy sources. In 2002, green certificates were traded at around € 0.08 per kWh /IEA 2003/. Other support mechanisms are either technology-specific or involve direct financial support. This is the case for photovoltaic (PV) systems, which received approximately 100 Mio € of public funding to stimulate their diffusion /IEA 2003/. On July 2005 the Industry and Environment Ministers approved the Feed-In Tariff for photovoltaic energy systems. This law, the so called "Conto Energia", has been introduced in Italy for any PV systems between $1kW_{el}$ and $1MW_{el}$ connected after the 30 September 2005. The incentives are between 0,445 and 0,490 $€_{05}$/kWh and will last for 20 years /ProRinnovabili 2005/.

No comprehensive evaluation of the potential of RES in Italy exists at the moment. Several assessments have been made for each renewable energy resource, but the conclusions are often in disagreement and difficult to reconcile. High-temperature applications for process heat or for electricity production are today of little importance, although there have been RD&D efforts in the past and again at present until July 2005, when the government decided to remove the director of ENEA, the Nobel Prize Winner for Physics Carlo Rubbia. He was the biggest supporter of CSP systems and the inventor of the new fluid (a mix of molten salt) to be used as HTF in a new generation of parabolic troughs, which was to be installed in Priolo Gargallo. The future of the plant is now uncertain. Rubbia is now working for CIEMAT, the major Spanish research institution on CSP systems. According to the scientist, the main problem for the exploitation of CSP was the fact that, despite having waited for one and a half year, this kind of technology has never been recognised by the authorities as a renewable source of energy, therefore losing all the related legislative benefits (the new Green Certificate system) and the interest from industrial actors.

Surely the conditions for CSP systems in Italy are somewhat worse than in other Mediterranean countries, because of the lower proportion of direct to total solar radiation but the biggest problems are the bureaucratic and institutional barriers, the insufficient information to the public, the decrease in RES´ R&D and the minimal role played by the national industry. Conflicts of power concerning energy policy between central and regional governments have also been a retarding factor.

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List of abbreviations:

ANU	Australian National University
CLFR	Compact Linear Fresnel Reflector
CPS	Compound Parabolic Concentrator
CSP	Concentrated Solar Power system
DISS	Project “Direct Solar Steam Generation”
DISS-2	Project “Direct Solar Steam Generation”-Phase 2
DLR	Deutsches Luft- und Raumfahrt Zentrum
DSG	Direct Steam Generation
DTIRC	Dielectric Total Internal Reflection Concentrator
EPC	Engineering, Procurement and Construction
GEF	Global Environmental Facility
GIS	Geographical Information System
GOML	Glass-on-Metal-Laminate
HCE	Heat Collecting Element
HTF	Heat Transfer Medium
IEA	International Energy Agency
INDITEP	Integration of Direct solar steam Technology for Electricity Production
ISCC	Integrated Solar Combined Cycle
KJC	Kramer Junction Operating Company
LEC	Levelised Electricity Costs
LS-1	Luz Solar – 1 Collector
LS-2	Luz Solar – 2 Collector
LS-3	Luz Solar – 3 Collector
LS-4	Luz Solar – 4 Collector
NSW	New South Wales
O&M	Operation and Maintenance
PCS	Prototipo Collettore Solare
PR	Progress Ratio
PS10	Planta Solar 10 MW_{el}
PSA	Plataforma Solar de Almeria
PV	Photovoltaic
R&D	Research and Development
RES	Renewable energy system
S&L	Sargent & Lundy
SEGS	Solar Electric Generating System
SBP	Schleich Bergermann und Partner
SCR	Solar Central Receiver
SSPS	Small Solar Power Station
WIS	Weizmann Institute