EVALUATION OF THE POTENTIAL OF CENTRAL RECEIVER SOLAR POWER PLANTS: CONFIGURATION, OPTIMIZATION AND TRENDS

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Abstract

This paper presents a parametric analysis for a medium to large size (290-to-500 MW_{th} receiver thermal power) Central Receiver plant considering the present market trends. The analysis is divided in 4 steps:

- Size and location analysis: for a medium to large size Central Receiver power plant, three turbine power and three different locations that are involved in the development of power tower plants, have been analyzed to assess the impact over the design characteristics of the solar field and receiver sub-systems and over the levelized electricity cost,
- Technology analysis: as commercial power tower plants in operation today are mainly using steam and molten nitrate salts, the present analysis compares the two main technologies, without thermal energy storage to evaluate both under similar design conditions,
- Storage analysis: thermal energy storage increases the value of electricity produced and the plant capacity factor for both technologies (steam and molten nitrate salts). For this reason, the analysis shows for each optimized solar field and receiver thermal power, the optimum combination of turbine power and thermal energy storage that minimizes the levelized electricity cost, for both technologies,
- Component's cost analysis: market trends are focused on the specific cost reduction by means of larger plant size and through an improved economy of scale. As a result, and based on baseline cost parameters widely accepted in solar industry, an analysis over the specific costs of major components on the electricity cost has been carried out, to lead where the research and development efforts should be made.

Keywords: Levelized electricity cost, molten nitrate salts, direct steam generation, steam, thermal energy storage, central receiver.

Acronym

BOP	Block of Power
CR	Central Receiver
DNI	Direct Normal Irradiance
DSG	Direct Steam Generation
HTF	Heat Transfer Fluid
ITD	Initial Temperature Difference
LEC	Levelized Electricity Cost
MNS	Molten Nitrate Salts
NREL	National Renewable Energy Laboratories
O&M	Operation and Maintenance
PCM	Phase Change Material
PSA	Plataforma Solar de Almeria
RMS	Root Mean Square
SAM	System Advisor Model
STE	Solar Thermal Electricity
STPP	Solar Thermal Power Plants
TES	Thermal Energy Storage
TIOS	Total Investment at Operation Startup
TMY	Typical Meteorological Year

Nomenclature

A	Area
C	Cost
crf	Fixed charge rate
E_{net}	Annual net electricity
k_d	Real debt interest rate
K_{fuel}	Annual fuel costs
$k_{insurance}$	Annual insurance rate
K_{invest}	Total plant investment
$K_{O\&M}$	Annual operation and maintenance costs
n	Depreciation period in years
P	Gross power rating
S	Slant range from heliostat to receiver
y	Year

Subscript

e	electrical
PB	power block
rec	receiver
ref	reference
SG	steam generator
th	thermal

Superscript

x	scaling exponent

Symbol

η	efficiency (design point for power block)

τ atmospheric transmittance

1. Introduction

Solar thermal power plants (STPP) have a great capacity for large-scale electricity generation and the possible combination with thermal energy storage and/or hybridization with backup fossil fuels. These options make possible to supply an important amount of the energy demand in the countries of the solar belt [1]. The first generation of grid-connected power plants for electricity production, based on solar thermal electricity (STE) plants with central receiver (CR) system technology using large heliostat fields and a solar receiver placed on the top of a tower, is currently being boosted by the first commercial plants in Spain, PS10, PS20 and Gemasolar; and in USA, Sierra Sun Tower and Coalinga plant, Ivanpah project, and Tonopah projects which are in the pipeline to start production next years. Nowadays, other countries besides Spain and the USA, are implementing STE projects such as India, China, Israel, Australia, Algeria, South Africa and Italy due to its appropriate solar resource.

Present trends are focused on the specific cost reduction by increasing the plant size through an improved economy of scale. On the other hand, the larger plant size the larger optical losses due to atmospheric attenuation and the higher spillages associated to large solar fields with optimized receiver sizes.

Moreover, the first generation of commercial STE with CR technology is based on technological developments matured after more than two decades of research, using cavity or external tube receivers with saturated steam and molten salts schemes respectively. Other developments are being implemented with superheated steam, Sierra Sun Tower in USA and Khi Solar One in South Africa, or larger plant sizes, Crescent Dunes (110 MW_e) and Ivanpah Solar Electric Generating Station (377 MW_e) in the USA.

As a result of the aforementioned commercial situation, this work presents an analysis over the following factors for a medium to large size CR power plants (between 0.5 to 1.0 km^2 solar field aperture with 290-to-500 MW_{th} receiver thermal power):

1. The solar field optical efficiency and relative levelized electricity cost (LEC) for three locations (Seville-Spain, Daggett-USA and Carnarvon-South Africa) due to its relevance in the STE market,
2. The main implications of the receiver using molten salts and superheated steam as heat transfer fluid,
3. The impact of different combinations of thermal energy storage and power block sizes for a given reflective surface,
4. The specific cost of major components (heliostat, receiver, thermal storage, power block, steam generator and operation-maintenance) over the expected LEC.

Section 2 presents a detailed description of the four analyses carried out on the paper taking into account the general considerations (modeling, optimization and simulation tools as well as the boundary conditions) introduced on section 3. The methodology used on the simulations and the results of the four cases are presented on section 4. Finally, on section 5, main conclusions of the different analysis are pointed out.

2. Description of the analysis

2.1. Reference system design

This section describes the STPP configuration that is considered as the reference system for the analysis. It consists on a CR power tower with TES, located next to Seville, Spain. Fig. 1 depicts a schematic view of this reference system. The main sub-systems are the solar field, receiver, TES system, power block, and steam generator.

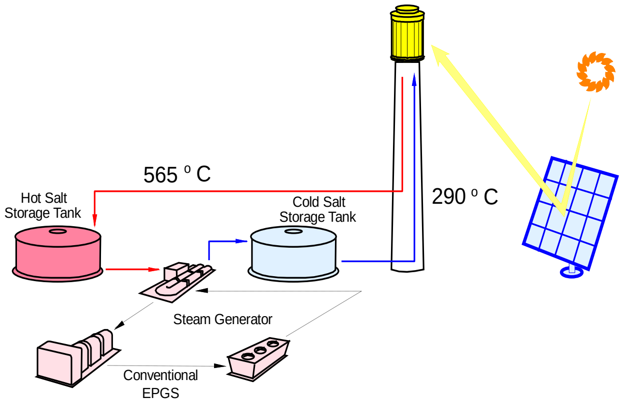

Fig. 1. Scheme of the MNS reference power tower plant

The HTF in the receiver is MNS, which is heated from 290 ºC to 565 ºC, and the working fluid in the BOP is steam. The MNS is an eutectic mixture of 60%/40% by weight of sodium/potassium nitrates respectively, called Solar Salt. The thermodynamic cycle is a regenerative Rankine cycle with reheat. The heat exchanger transfer thermal energy from the MNS to the water/steam in the steam generator to run the turbine. The storage is an indirect system [2] that stores salts to work the turbine 15 hours at full load without solar irradiation [3]. The main parameters of the reference plant are presented in Table I.

Based on the financing and baseline costs presented on section 3.3. the estimated LEC for the reference plant is 22.442 c€/kWh. Fig. 2 shows the influence of the sub-systems of the reference power plant over the LEC.

Table I. Reference plant main parameters

Net aperture, m^2	305,704
Optical tower height, m	140
Receiver thermal power, MW_{th}	120
TES, h	15
Gross output power, MW_e	19.9
Annual energy production, GWh	95

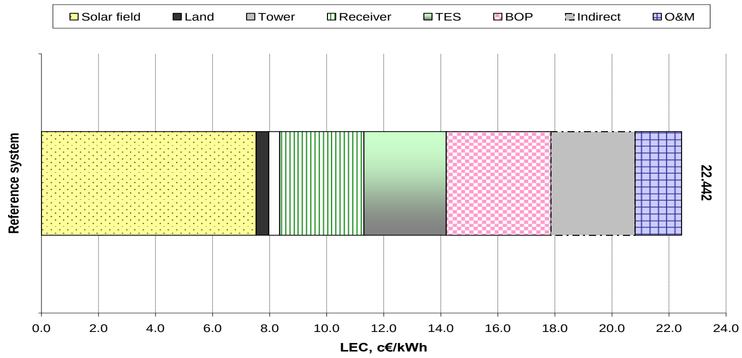

Fig. 2. Influence of the sub-systems of the reference power plant over the LEC

2.2. Case I: Size and location analysis

Given the success of the first commercial CR plants, short-medium term designs tend to increase the plant size with larger solar fields, receivers and power blocks to maximize the electricity generation and minimize the specific cost of the installation and, consequently the LEC. Even though there is who still believes that the key to reduce the LEC still lies in modular tower systems.

Case study I analyze three different locations (Seville–Spain, Daggett–USA and Carnarvon–South Africa), which nowadays are involved in the development of STE plants with CR technology, and three receiver thermal power of 270, 390 and 500 MW_{th}. For the power block, three electrical gross output turbines –56, 78 and 100 MW_e– have been selected respectively. The heat transfer fluid used is MNS that allows working the turbine at higher temperatures (nearly 575 ºC) and storing some excess energy.

The influence of the variation in the net electricity production and its location has been analyzed to assess the impact over the main design characteristics of the solar field and the receiver sub-systems and over the relative LEC, with respect to the reference system, on the present market.

2.3. Case II: Technology analysis

STE plants with CR technology in operation today include matured technologies and designs. Current steam receivers (PS10, PS20 –with saturated steam– and Sierra Sun Tower –with superheated steam–) are based on the well known steam boiler technology while MNS receiver (Gemasolar) has taken advantage of the knowledge about Solar Two [4, 5].

The thermal energy storage system for steam receivers is not well solved yet, highlighting a commercial thermal storage supply of 50 minutes of plant operation at 50% load for PS10 [6]. Moreover, direct steam technology providers have marketed their solution as a practical, cost-effective method for system without storage. For this reason, the case study II presents a comparative analysis between the two main technologies developed (direct steam *vs* molten salts) in terms of several parameters such as the relative LEC, with respect to the reference system, solar field efficiency, receiver efficiency, power block, parasitic efficiency and overall plant efficiency, without TES system, to evaluate both under similar design conditions.

2.4. Case III: Storage analysis

Commercial electricity-generating power tower plants under construction include Khi Solar One in South Africa with 50 MW_e power and 2 hours of thermal energy storage [7], Ivanpah Solar Electric Generating Station with 377 MW_e steam towers in California (USA) and Crescent Dunes Plant in Tonopah with 110 MW_e power with 10 hours of TES [8] MNS tower in Nevada (USA). Moreover, recently two important companies have signed a partnership to construct and operate the two largest solar power tower in California with 250 MW each one. This scenario confirms the increasing power plant size trend. Molten salt power tower technology used to have large thermal energy storage as a result of the lowest LEC [9]. Future direct steam power towers will likely include at least a few hours of TES to increase the value of electricity produced and increase capacity factor as well as dispatchability that is an important key for the grid operator, like Khi Solar One in South Africa. A variety of storage options for steam systems is presented in [10].

Consequently, the case study III analyzes, for a given reflective surface and the two main technologies (MNS and DSG system), the impact of different combinations of thermal energy storage and power block sizes over the net electricity production and the relative LEC, with respect to the reference system.

2.5. Case IV: Component's cost analysis

Market trends are focused on the specific cost reduction by increasing the plant size through an improved economy of scale even though newer schemes are claiming the economics of smaller units [11]. The cost of power tower plants can be reduced by [9]:

- Reducing equipment capital cost via reduced material content, lower-cost materials, more efficient design, or less expensive manufacturing and shipping costs,
- Reducing field assembly and installation costs via simpler designs and minimization and/or ease of field assembly,
- Lowering operation and maintenance costs through improved automation, reducing need and better O&M techniques,
- Building larger systems that provide economies of scale,
- Deploying more systems to benefit from learning-curve effects.

As a result, case study IV analyze for the location of Daggett–USA three receiver thermal power (270, 390, 500 MW_{th}) with the gross output power and the TES hours resulting of minimizing the relative LEC in section 4.3.2, carrying out a sensitivity analysis over the specific costs of major components –solar field, solar receiver, thermal storage, power block, steam generator and operation and maintenance–.

3. General considerations

3.1. Conditions for the studies

For all cases, a surround heliostat field is chosen because the Utility Studies [12-14] showed that it resulted in lower LEC than a north heliostat field for large plants. The 115.36 m^2 heliostat developed for Gemasolar is selected due to its demonstrated capacity to accomplish with required feasibility and profitability [15]. The optical error for the heliostat is taken as 2.3 mrad RMS [16] with a mirror reflectivity assumed to be 90%. Solar mirrors are available today that are 94%; this was reduced by an assumed cleanliness factor of 96% [8].

For the turbine, a combined reheat and regenerative Rankine cycle is considered. The nominal thermal-to-electric efficiency is calculated for an inlet temperature of 575 ºC, an inlet pressure of live steam of 100 bar, a condensing pressure of 0.04 bar and 16 ºC ITD at design conditions between the steam at the turbine outlet (condenser inlet) and the ambient temperature. For the condenser type, an air-cooled system was chosen. Fig. 3 depicts the turbine efficiency at nominal conditions for different power ranges [17]. The thermal-to-electric efficiency increases rapidly for lower power ranges while achieving a plateau for higher power ranges. The higher the inlet temperature is, the higher thermal-to-electric efficiency will be.

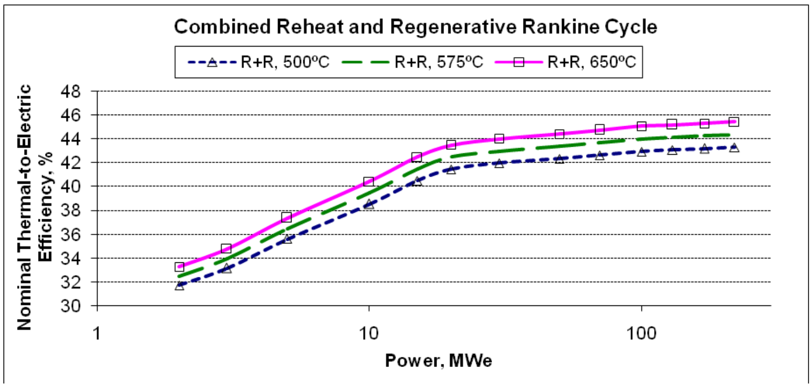

Fig. 3. Combined reheat and regenerative rankine cycle efficiency for various power ranges. 2-to-220 MW_e range

3.2. Computing tools for modelling, optimization and simulation.

WINDELSOL 1.0 [18-20] is an adaptation of the well-known Sandia National Laboratories DELSOL3 code [19,21] for Windows, in an environment with functions such as user-friendly interface, optimized defined-by-coordinates heliostat field generation, calculation of solar flux distribution on the absorber and graphic representation of optical parameters, heliostat field array, tower and solar receiver. WINDELSOL is used to develop the optical designs. The code provides the receiver dimensions, the tower height and the number and optimum distribution of heliostats necessary to absorb the specific amount of thermal energy into the HTF flowing through the receiver. DELSOL is an optical design tool widely used for STPP with CR technology, as the design of PS-10 and PS-20 commercial power towers plants in southern Spain.

The U.S. National Renewable Energy Laboratory's SAM is a publicly available open access model based on more than two decades of collaboration between NREL and the STE industry. SAM computer code [22], which is based on the Transient System

Simulation program TRNSYS [23], is used to predict the annual energy production of the power plant designs, as well as the evaluation of thermal losses in the receiver and sub-systems and overall plant efficiencies. Using this software tool, the operation of a STPP with CR technology can be simulated over a full year using TMY data [24].

The software tools used in this study (DELSOL, WINDELSOL and SAM) have been used within previous studies of power towers [25-33]. Moreover, own tools have been used.

3.3. Financing and baseline costs parameters

For the evaluation of the LEC, the following costs are assumed to represent what can be accomplished in early commercial plants that are currently planned or under construction [8]:

- Land: 2 €/m^2,
- Solar Field: 200 €/m^2,
- Reference Solar Receiver: 200 €/kW$_{th}$,
- MNS Thermal Storage: 30 €/kWh,
- PCM Thermal Storage: 50 €/kWh [34],
- Reference Power Block: 1000 €/kW$_e$,
- Steam Generator: 350 €/kW$_e$,
- Fixed Operation & Maintenance: 65 €/kW$_e$/y.

The cost values for the *Solar Receiver* and *Power Block + Steam Generator* are used to calculate the cost of a reference design (similar to Gemasolar) and then the final cost of both sub-systems are reduced through an improved economy of scale with the receiver area and the gross power rating the power block respectively. The expressions are of a form commonly used in chemical process industries [35]:

$$C_{rec} = C_{rec,ref} \cdot \left(\frac{A}{A_{rec,ref}} \right)^{x_{\mathrm{rec}}}$$

$$C_{PB+SG} = C_{PB+SG,ref} \cdot \left(\frac{\eta_{th-e} \cdot P}{P_{ref}} \right)^{x_{\mathrm{PB+SG}}}$$

LEC for the CR plants was calculated with the following according to [21, 36]:

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

where

$$crf = \frac{k_d \cdot (1 + k_d)^n}{(1 + k_d)^n - 1} + k_{insurance}$$

The crf is the parameter that includes all the capital-financing related assumptions in the analysis. The values used in the paper are based on usual financing parameters similar to that in [36], shown in Table II:

Table II. Financing parameters

Annual insurance rate	1 %
Real debt interest rate	8 %
Plant life time	30 y
Plant availability	93 %
Indirect costs	16.5 %
Construction period	2 y
Interest of investment during construction period	10.08 %
Fossil fuel backup	No
Subsidies	No

4. Methodology and results

4.1. Case I: Size and location analysis

The three sites selected are those involved in the implementation of STE plants with CR technology. Main specifications adopted are summarized in Table III [37-38]:

Table III. Selected locations characteristics

Site	Seville Spain	Daggett USA	Carnarvon South Africa
Latitude, º	37.42	34.87	-30.97
Longitude, º	-5.9	-116.8	22.13
Altitude, m	31	588	1309
Design Point DNI, W/m^2	900	950	1000
Annual Energy DNI, kWh/(m^2·y)	2089	2791	2995

MNS receivers have been demonstrated in pre-commercial demonstrations plants in the USA at a 5 MW_{th} scale (Sandia National Laboratories) and at a 40 MW_{th} scale (Solar Two) and in Europe at a 10 MW_{th} receiver tested in France (Themis) [39]. The first commercial plant began operation in Spain in 2011, with Gemasolar project that uses a 120 MW_{th} receiver. This paper has focused in the next generation of thermal receivers with powers that ranged from 270 to 500 MW_{th} and different power productions with several hours of TES.

The trend to reduce specific costs by increasing the plant size is partially restricted, for STE with CR technology, mainly by the loss of optical efficiency due to atmospheric attenuation. Moreover, higher spillages are associated to both the larger errors (misalignment, wind disturbance, etc.) of the further away located heliostats and with optimized receiver sizes.

WinDelsol [18] provides the optical design of the selected power plants. Fig. 4 shows the expected field efficiencies at design point and annual performance versus the necessary reflective surface (km^2) for three locations and three receiver thermal powers for MNS technology. Fig. 4 shows that for similar optical efficiencies, the location of Seville (Spain) needs higher reflective surface to supply the necessary thermal power onto the receiver whilst the location of Carnarvon (South Africa) requires the lowest reflective surface.

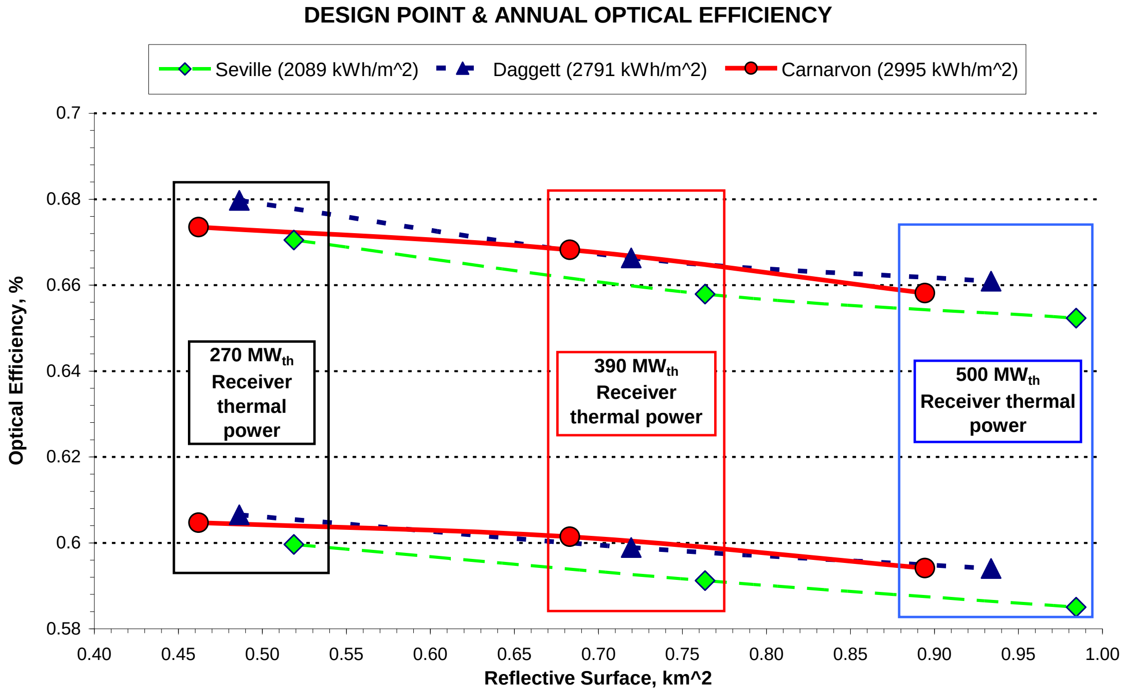

Fig. 4. Design point (upper lines) and annual optical efficiency (lower lines) *vs.* the reflective surface for 3 locations and 3 receiver thermal power

Once the field layout is optimized it is used as a new input for SAM to predict the annual energy production of the optimized power plant designs. With these results, the variation over the LEC of the optimized plant designs is analyzed.

Table IV presents, for three sites (Seville–Spain, Daggett–USA and Carnarvon–South Africa) and three receivers thermal power (270, 390 and 500 MW_{th}), the basic design characteristics. Furthermore, Fig. 5 depicts the relative LEC, plant investment, net annual energy and reflective surface, with respect to the reference system.

Table IV. Basic design characteristics for the nine selected cases and the reference system

Location	Reference	Seville			Daggett			Carnarvon		
Tower height, m	140	155	180	215	150	175	200	145	170	190
Receiver surface, m^2	300	452	669	865	452	670	866	450	670	876
Receiver thermal power, MW_{th}	120	270	390	500	270	390	500	270	390	500
TES, h	15	6	7	7	7	8	8	8	9	9
Gross output power, MW_e	19.9	56	78	100	56	78	100	56	78	100

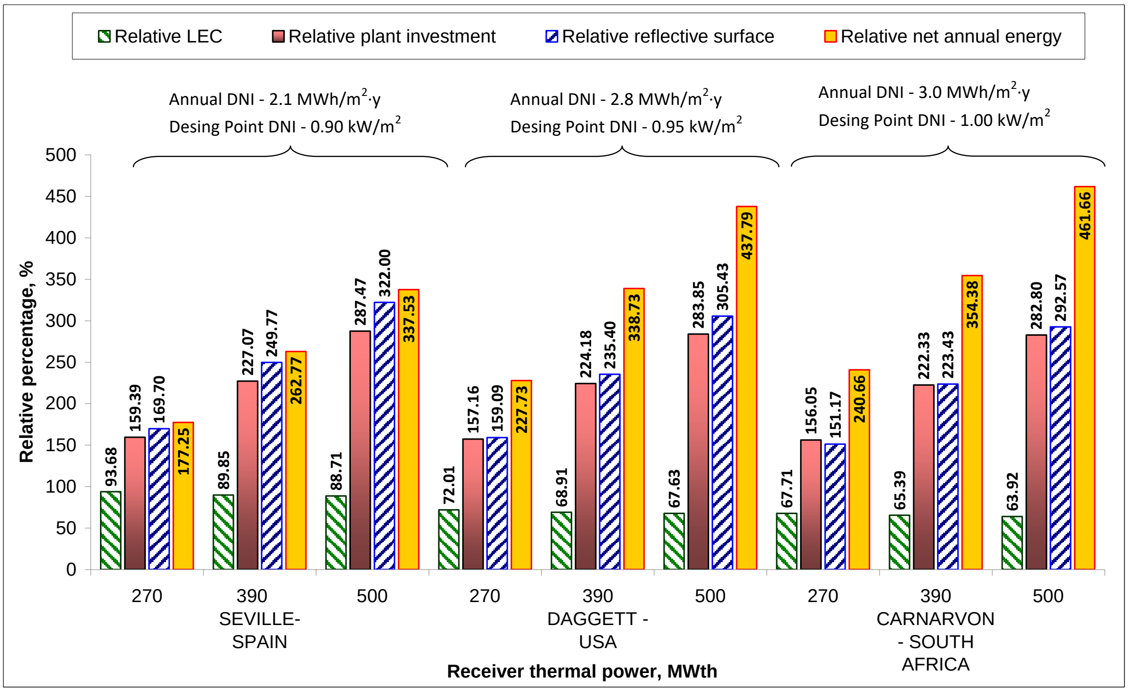

Fig. 5. Summary of the relative LEC, plant investment, net annual energy and reflective surface for the cases of Table IV

For the three locations, increasing the receiver thermal power means a relative LEC reduction and relative net annual energy increase. Moreover Fig. 5 depicts an almost constant relationship between the total direct plant investment and the reflective surface for all the nine cases analyzed, with an increasing of both factors by increasing the receiver thermal power of each plant.

Comparing the plant performance in the three locations, it can be concluded that an increase of the annual DNI entails a reduction of LEC and an increase of net annual energy, what in the cases of study of this paper means higher LEC and lower net annual energy in Seville than Daggett and Carnarvon. On the other hand, reflective surface and plant investment increase with an annual DNI decrease. The comparison for a MNS CR technology with a receiver thermal power scale-up factor of 1.9, from 270-to-500 MW_{th}, presents an improvement in the LEC due to scaling up the plant of 5.3% for Seville, 6.1% for Daggett and 5.6% for Carnarvon. This LEC reduction does consider no improvement in manufacturing costs. Moreover, the analysis shows that for a similar receiver thermal power, the net annual energy could be increased around 35%, from Seville-to-Carnarvon, whilst reduces the LEC around 28%. The LEC reduction from Seville-to-Daggett is 23%.

With respect to the reference power tower plant (120 MW_{th}), simulated cases present a scale-up factor of the receiver thermal power between 2.3 (270 MW_{th}) to 4.2 (500 MW_{th}). Analyzing the evolution of relative LEC it can be stated that for the highest receiver thermal power (500 MW_{th}), the LEC decreases in Seville, Daggett and Carnarvon by 11.3%, 32.4% and 36.1% respectively. Furthermore, it can be observed that the relative annual energy production increases with the receiver thermal power in different scale-up factor depending on the annual DNI. Therefore, it is noticeable that the relative annual energy production scale-up factor is lower, similar and higher in Seville, Daggett and Carnarvon respectively (Table V).

Table V. Scale-up factors comparison with respect to the reference plant

Receiver thermal power scale-up factor		2.3	3.3	4.2
Net annual production scale-up factor	Seville	1.8	2.6	3.4
	Daggett	2.3	3.4	4.4
	Carnarvon	2.4	3.5	4.6

4.2. Case II: Technology analysis

Although it is widely assumed that any molten salt receiver would have accompanying with thermal energy storage, since this is a key benefit of the MNS concept, direct steam technology providers have marketed their solution as a practical, cost-effective method for system without storage. As a result, the present section is focused on the analysis of the differences between MNS and DSG technologies without TES while section 4.3 would analyze in depth the different options for the TES for both technologies.

The performance of a MNS without thermal storage is similar to a parabolic trough power plant which has a buffer tank that absorbs oil changes. In this particular case, a drainage tank is considered to store the salts during transients or night periods.

For the design of both DSG and MNS plants the following assumptions have been made:

- The location of Seville is selected for the analysis,
- Thermodynamic conditions adopted for the steam going to the power block are the same in both technologies,
- The same electrical gross output is delivered (111 MW_e),
- The solar field/receiver has been designed for a maximum solar flux over the receiver of ~1 MW/m^2 [8] for MNS technology and for the DSG the maximum solar flux is sub-divided as function of the type of receiver. For the boiler the maximum solar flux is ~0.8 MW/m^2, for the super-heater is ~0.5 MW/m^2 and for the re-heater is ~350 kW/m^2 [22],
- The tower height is set to 170 m.

DSG consists of superheated steam at 575ºC and 100 bars that feeds the high pressure turbine. The receiver includes a re-heater where a portion from the high pressure turbine outlet is redirected and reaches a temperature of 500ºC and then passes through the remainder of the power cycle. MNS outlet temperature from the receiver is 580ºC, and produces steam at 575ºC and 100 bar.

With respect to the parasitic, common losses have been considered for both technologies: heliostat, piping, auxiliary heater, and self-supply. And, in the case of MNS additional losses due to the necessity of pumping the HTF through the heat exchanger and through the drainage tank; And the necessity of maintaining the salt temperature during transient and night periods as well as the system preheating on start-up.

First, an analysis for different solar multiples (ratio of the thermal power that is absorbed in the receiver fluid and delivered to the base of the tower at the system design point to the peak thermal power required by the turbine-generator [21]) is carried out, to find out the one that minimized the relative LEC and/or maximizes the relative overall plant efficiency.

Fig. 6 depicts the solar multiple optimization for both power plants without thermal energy storage. The LEC calculation, for the DSG system, has neglected the cost related to the steam generator.

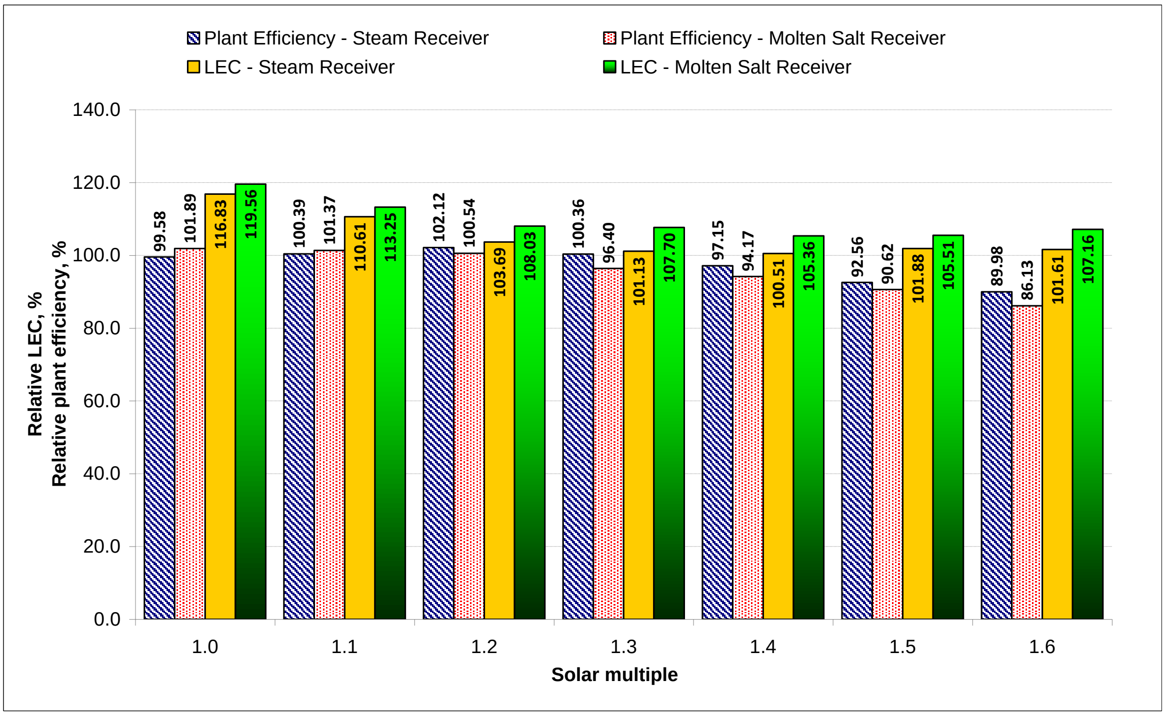

Fig. 6. Solar multiple optimization as function of the relative LEC – plant efficiency for a MNS and DSG system

The results depicts that, for the DSG technology, the solar multiple which maximizes the plant efficiency is 1.2 while the solar multiple that minimizes the LEC is 1.4. For the MNS technology, the solar multiple which maximizes the plant efficiency is 1.0 while the solar multiple that minimizes the LEC is 1.4.

Second, as a result of Fig. 6, Table VI shows the basic design characteristics and efficiencies for a solar multiple of 1.1 at which, both technologies have similar relative plant efficiency and relative LEC.

Table VI. Characteristics and efficiencies for for a DSG and a MNS power tower with a solar multiple of 1.1.

[1] Net annual energy for a plant availability of 100 %

Solar Multiple	1.1	
Technology	DSG	MNS
Receiver thermal power, MW_{th}	277.8	277.8
Receiver surface, m^2	724	471
Heliostat number, -	4574	4645
Total convective losses, GWh/y	54.77	22.56
Total radiative losses, GWh/y	20.31	23.16
Solar field annual efficiency, %	51.95	50.38
Receiver annual efficiency, %	80.89	80.26
Power block annual efficiency, %	38.88	41.26

Parasitic efficiency, %	91.40	90.66
Net electric output [1], GWh	164.7	168.9
Relative LEC, %	110.61	113.25
Plant efficiency, %	14.93	15.08

The solar field efficiency is 1.6% higher for DSG mainly because the spillages for a larger area are lower.

Furthermore, the worse heat transfer for water/steam compared with MNS causes that the flux working ranges are lower for the first ones (Table VII). This involves that the necessary surface for the heat transfer mechanisms is larger so the convective losses of a DSG are larger than just the increase due to the larger surface. However, the efficiencies of both receivers are quite similar for this solar multiple.

Table VII. Flux ranges of solar tower receivers

Fluid	Water/Steam	MNS
Flux, kW/m^2		
- Average	100 – 300	400 – 500
- Peak	400 – 800	700 – 1000

As the MNS plant presents shorter starting-up and shutdown times compared with heated steam plants and, at the same time, transients have a better behaviour on MNS plant, power cycle works more time a year in nominal conditions for MNS plant maximizing the efficiency of the plant and decreasing LEC. This fact is even more impacting taking into account storage: in this case, power cycle is decoupled from the solar radiation, eliminating transients on the turbine and reducing turbine starting-up time.

The total parasitic losses are higher for the MNS system than for the DSG. Besides the heliostat, the piping and the auxiliary heater losses for both technologies, the MNS system includes the required pumping power for the HTF through the power block; which means higher parasitic losses for a power tower with MNS than for a power tower with DSG.

The minimum relative LEC for a DSG power plant is 100.51 % for a solar multiple of 1.4 while the minimum relative LEC for a MNS power plant is 105.36 % for a solar multiple of 1.4. The variation is within 1.1 c€/kWh.

As a conclusion it can be stated that, for a power tower without thermal energy storage and with the same thermodynamic requirements for the power block, a DSG system results in a lower LEC than a MNS system and a similar LEC than the reference plant with 15 hours of TES. Previous studies confirm this prediction [9].

4.3. Case III: Storage analysis

TES increases the value of the electricity produced. That the reason why MNS power tower plants include large TES. On the other hand, TES for DSG in under intensive research to achieve competitive values. The main options for both technologies are:

a) MNS: TES for molten nitrate salt technology is based on the active direct storage systems [40]. It consists of two tanks, the hot tank to store the HTF coming from the receiver, in order to use it during cloudy periods or nights. The cold tank where the cooled HTF remains waiting to be heated. Fig. 1 depicts a schematic view of the reference system, that uses molten nitrate salts as HTF.

b) DSG: TES for direct steam generation technology is based or in an active direct storage system or in a combination of an active indirect and passive storage system [40]. The first option, direct storage of saturated or superheated steam in pressure vessels, is not economic due to the low volumetric energy density [41]. The second type has three different storage options under investigation [34]. All of them uses PCM storage for evaporation/condensation storage [42]. The main changes in the configuration are mainly due to the sensible part with the usage of concrete [42] or molten salts storage. A storage system with a capacity of approximately 1MWh working at 100 bar was constructed by DLR combining a PCM module and a concrete module. The storage modules hvae been tested in a DSG-test facility specially erected at a conventional power plant of Endesa in Carboneras (Spain) [42].

Case III analyzes, for the two main CR technologies, (MNS and DSG), different combinations of TES and power block sizes over the net electricity production and relative LEC.

Previous studies have compared a reference technology with DSG with TES using PCM storage [34] or have analyzed a DSG with a theoretical TES system [43] for parabolic trough technology. For the analysis presented in this work, it has been considered the thermal behaviour of a theoretical thermal storage system [44], with a charging/discharge utilization factor and a global efficiency of 85% [45]. This value is applied in accordance with [46] that established the annual thermal storage efficiencies for Solar One and CESA-1 power plant, CR systems with DSG, 83 % and 84 % respectively.

For the design of both DSG and MNS plants the following assumptions have been made:

- Three locations (Table III) and three receiver thermal power (270, 390 and 500 MW_{th}) are analyzed,
- Thermodynamic conditions adopted for the steam going to the power block are the same in both technologies,
- The same electrical gross output is delivered (33-to-167 gross output MW_e) with a variation of TES hours (0-to-18),
- The solar field has been designed for a maximum solar flux over the receiver of ~1 MW/m^2 [8] for MNS technology and for the DSG the maximum solar flux is sub-divided as function of the type of receiver. For the boiler the maximum solar flux is ~0.8 MW/m^2, for the super-heater is ~0.5 MW/m^2 and for the re-heater is ~350 kW/m^2 [22],
- The same criteria adopted for the HTF in section 4.2 are adopted in this section.

The design criteria used for most of conventional and renewable power plants is the minimization of the electricity cost, LEC, for STPP. Therefore, Fig. 7 and Fig. 8 shows a detailed analysis about different combinations of TES (0-18 hours) and gross power output sizes (33-156 MW_e) over relative LEC, for a MNS and a DSG power plant respectively, in Seville, as an example of the methodology followed for the cases presented below. This location is selected because of its importance in the development of STPP with CR technology. With respect to the thermal power, it is also selected a receiver of 390 MW_{th}, corresponding to a scale-up factor of 3.3 respect to Gemasolar and 9.8 respect to Solar Two, as the intermediate step towards the envisaged 1000 MW_{th} capacity [8].

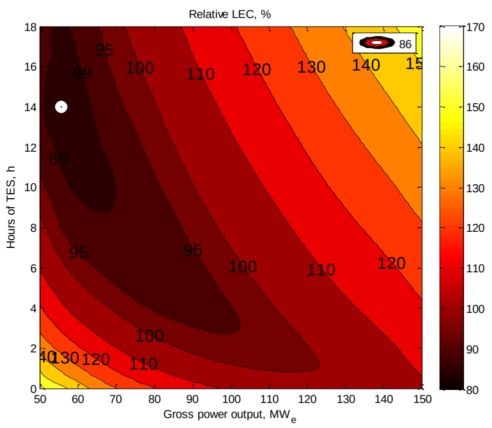

Fig. 7. Relative LEC for different combinations of TES and gross power output for a 390 MWth receiver with MNS technology and 0.76 km^2 reflective surface in Seville

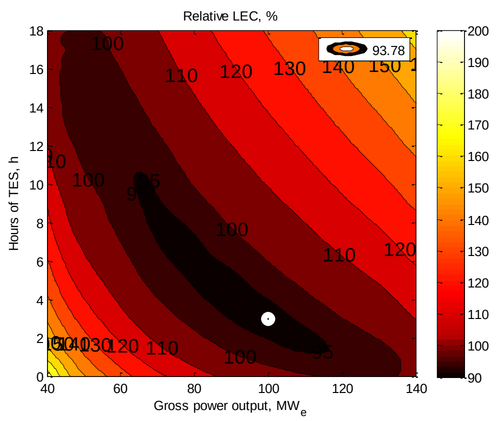

Fig. 8 Relative LEC for different combinations of TES and gross power output for a 390 MWth receiver with DSG technology and 0.76 km^2 reflective surface in Seville

For a receiver thermal power of 390 MW_{th} located in Seville, the analysis carried out for both technologies depicts:

- MNS: The minimum relative LEC occurs for a gross power output of 55.5 MW_e with 14 hours of TES with a relative LEC of 86.0%. The corresponding net electric generation is 251.3 GWh with an overall plant efficiency of 14.65%,
- DSG: The minimum relative LEC occurs for a gross power output of 100 MW_e with 3 hours of TES with a relative LEC of 93.8%. The corresponding net electric generation is 250.0 GWh with an overall plant efficiency of 14.62%.

For this particular case (390 MW_{th} in Seville), all the combinations of TES and gross power output, for DSG and MNS, have been presented in Fig. 7 and Fig. 8. Hereafter, the following sub-sections will present, using the same methodology, the minimum relative LEC, the corresponding TES hours and net electricity production for the aforementioned cases.

4.3.1. Seville – Spain

In accordance with the stated conditions in 4.3., Fig. 9 presents for both CR technologies, MNS and DSG, the minimization results for the relative LEC. The total reflective surface of the solar field is presented in the legend.

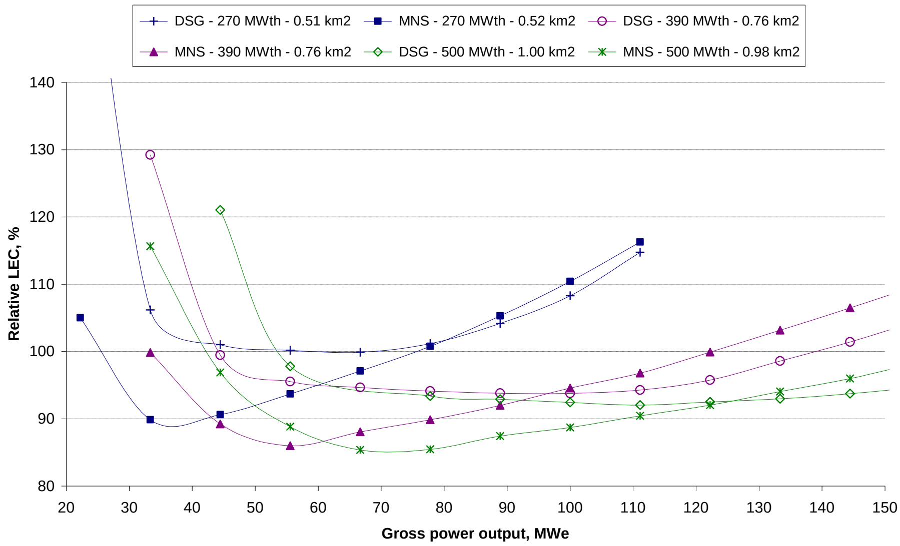

Fig. 9. Relative LEC minimization for different combinations of TES and power block sizes, for MNS and DSG technology, in Seville-Spain

Fig. 10 depicts the TES hours that minimizes the relative LEC of Fig. 9, for different gross turbines powers (22-to-166 MW_e) and TES hours (0-to-18 hours). This figure shows that both technologies minimize the relative LEC for the same TES hours in almost all the cases studied.

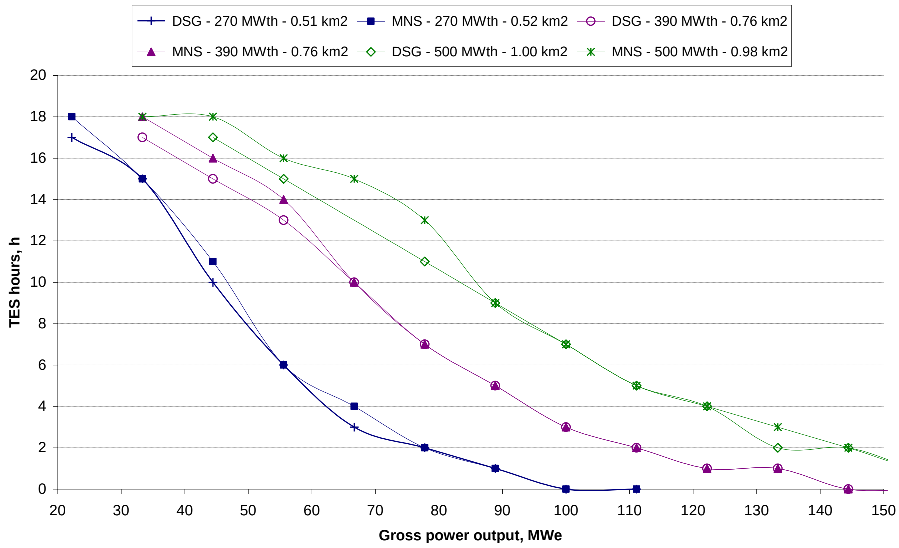

Fig. 10. TES hours that minimizes the relative LEC for different combinations of TES and power block sizes, for MNS and DSG technology, in Seville-Spain

Fig. 11 shows the net annual energy that minimizes the relative LEC for a MNS and a DSG CR technology. This figure presents an increasing net annual energy, depending on the receiver thermal power, until achieving a plateau for a turbine power that minimizes the LEC, with the TES hours presented in Fig. 10.

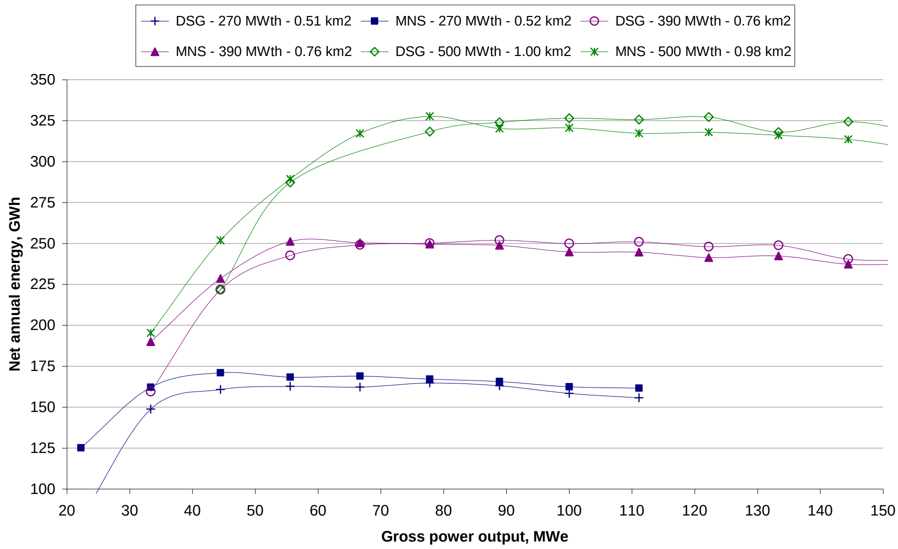

Fig. 11. Net annual energy that minimizes the relative LEC for different combinations of TES and power block sizes, for MNS and DSG technology, in Seville-Spain (100% plant availability)

Table VIII and Table IX summarizes the parameters that minimized the relative LEC for each receiver thermal power for both technologies.

4.3.2. Daggett – USA

In accordance with the stated conditions in 4.3., Fig. 12 presents for both CR technologies, MNS and DSG, the minimization results for the relative LEC. The total reflective surface of the solar field is presented in the legend.

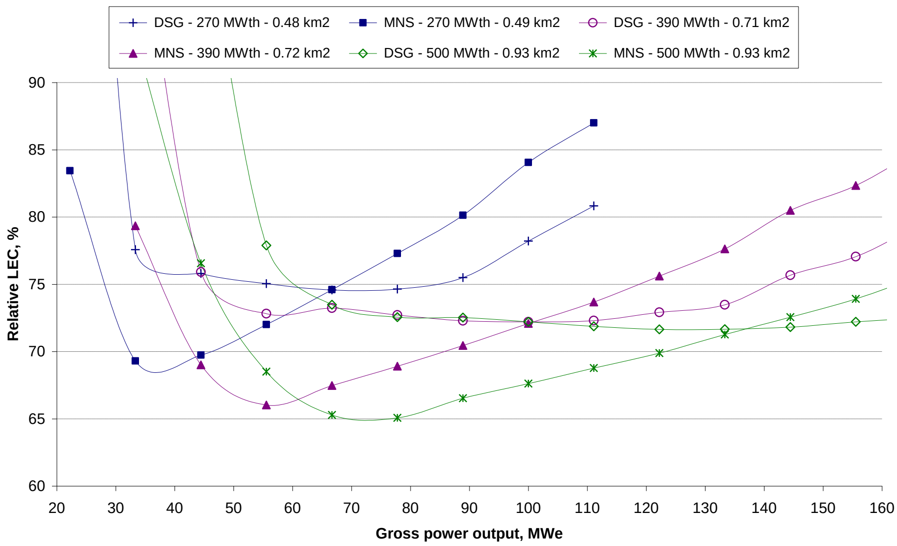

Fig. 12. Relative LEC minimization for different combinations of TES and power block sizes, for MNS and DSG technology, in Daggett-USA

Fig. 13 depicts the TES hours that minimizes the relative LEC of Fig. 12 for different gross turbines powers (22-to-166 MW_e) and TES hours (0-to-18 hours). This figure shows that DSG usually requires less TES hours than MNS technology to minimize the relative LEC.

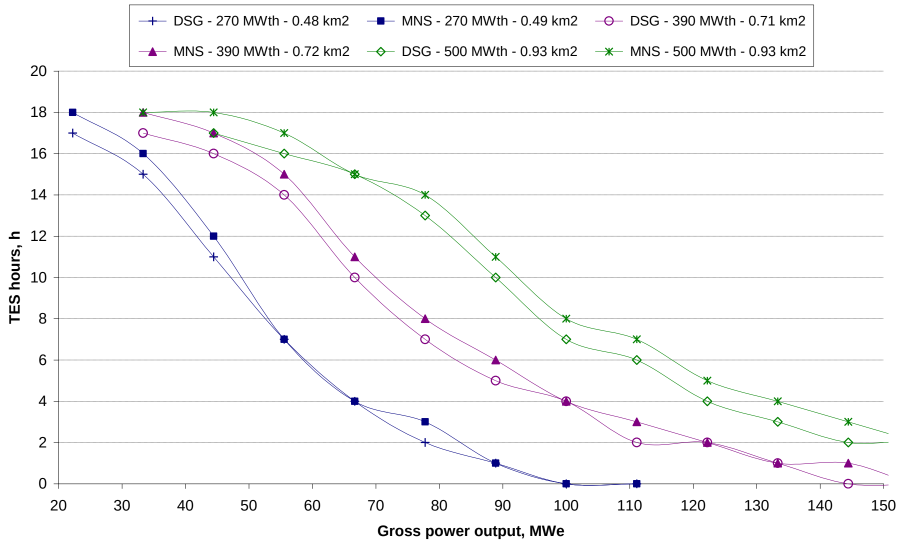

Fig. 13. TES hours that minimizes the relative LEC for different combinations of TES and power block sizes, for MNS and DSG technology, in Daggett-USA

Fig. 14 shows the net annual energy that minimizes the relative LEC for a MNS and a DSG CR technology. This figure presents the same behavior of Fig. 11.

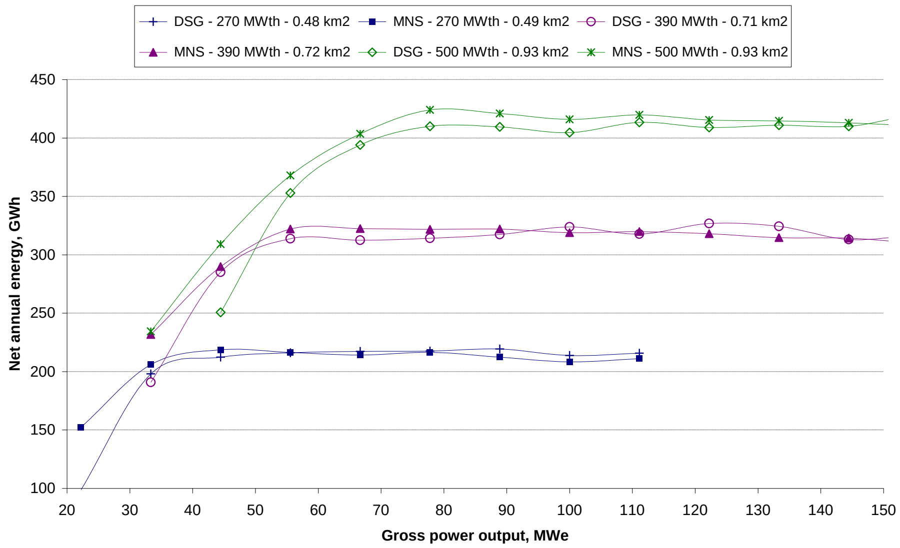

Fig. 14. Net annual energy that minimizes the relative LEC for different combinations of TES and power block sizes, for MNS and DSG technology, in Daggett-USA(100% plant availability)

Table VIII and Table IX summarizes the parameters that minimized the relative LEC for each receiver thermal power for both technologies.

4.3.3. Carnarvon – South Africa

In accordance with the stated conditions in 4.3., Fig. 15 presents for both CR technologies, MNS and DSG, the minimization results for the relative LEC. The total reflective surface of the solar field is presented in the legend.

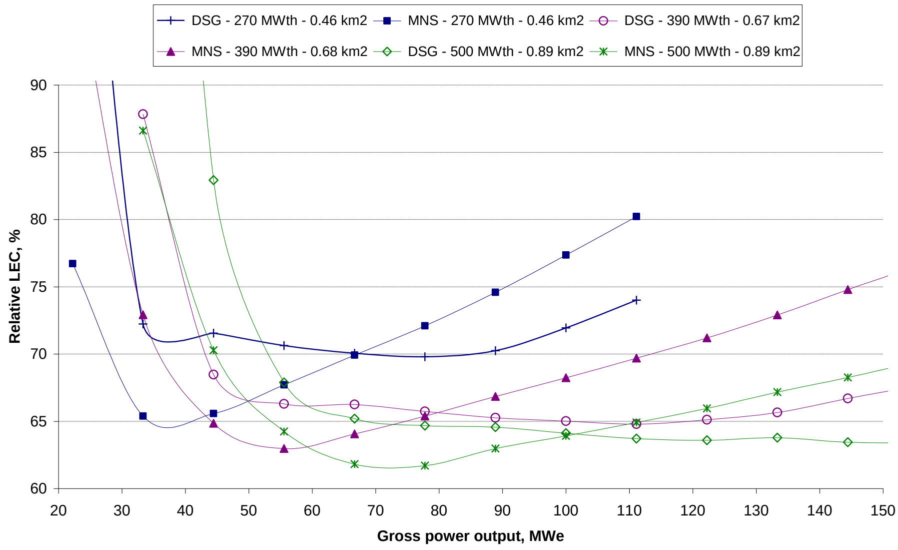

Fig. 15. Relative LEC minimization for different combinations of TES and power block sizes, for MNS and DSG technology, in Carnarvon – South Africa

Fig. 16 depicts the TES hours that minimize the relative LEC of Fig. 15 for different gross turbines powers (22-to-166 MW_e) and TES hours (0-to-18 hours). This figure shows that DSG usually requires 2 hours less than MNS technology to minimize the relative LEC.

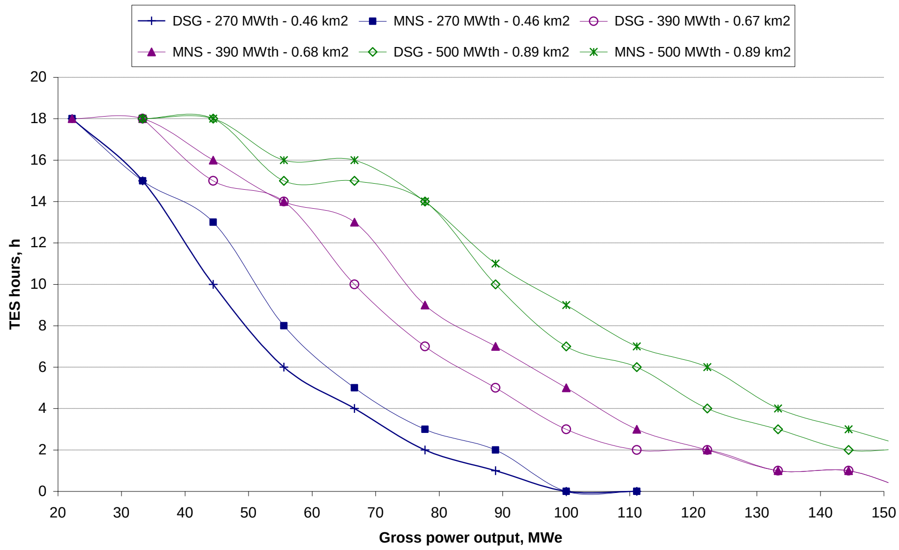

Fig. 16. TES hours that minimizes the relative LEC for different combinations of TES and power block sizes, for MNS and DSG technology, in Carnarvon – South Africa

Fig. 17 shows the net annual energy that minimizes the LEC for a MNS and a DSG CR technology. This figure presents the same behavior of Fig. 11 and Fig. 14.

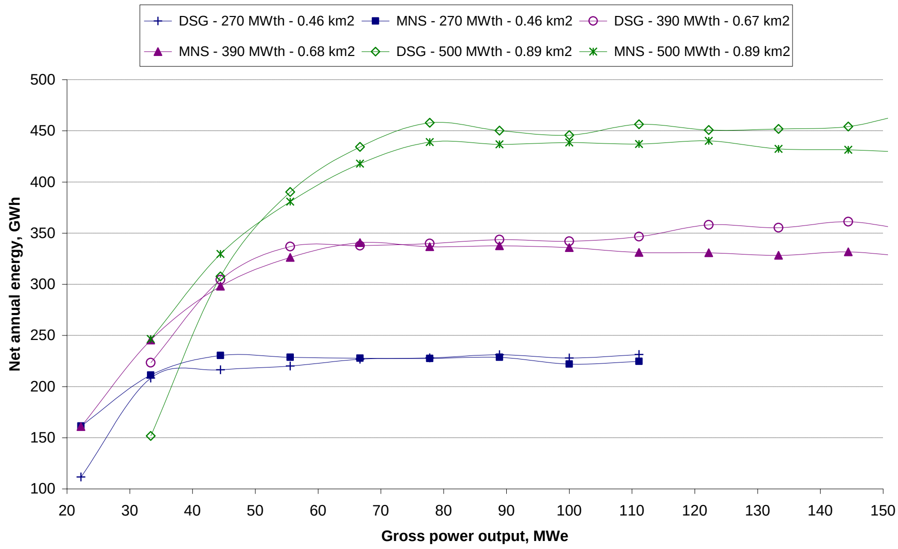

Fig. 17. Net annual energy that minimizes the relative LEC for different combinations of TES and power block sizes, for MNS and DSG technology, in Carnarvon – South Africa (100% plant availability)

Table VIII and Table IX summarizes the parameters that minimized the relative LEC for each receiver thermal power for both technologies.

Both technologies demonstrate, despite the location, that larger plants achieve lower LEC regardless of the technology.

Table VIII. Summary of basic parameters to minimize relative LEC for MNS

Location	Seville – Spain			Daggett – USA			Carnarvon – South Africa		
Receiver thermal power, MW_{th}	270	390	500	270	390	500	270	390	500
Relative LEC, %	89.9	86.0	85.4	69.3	66.0	65.1	65.4	63	61.7
Gross power output, MW_e	33	56	67	33	56	78	33	56	78
TES, h	15	14	15	16	15	14	15	14	14

Table IX. Summary of basic parameters to minimize relative LEC for DSG

Location	Seville – Spain			Daggett – USA			Carnarvon – South Africa		
Receiver thermal power, MW_{th}	270	390	500	270	390	500	270	390	500
Relative LEC, %	99.9	93.8	92.0	74.6	72.2	71.7	69.8	64.8	63.6
Gross power output, MW_e	67	100	111	67	100	122	78	111	122
TES, h	3	3	5	4	4	4	2	2	4

The outcomes (Table VIII-Table IX) reveal two main tendencies due to the importance of the thermal energy storage. MNS technology offers commercial, cost-efficient, and competitive storage system. As a result, for a receiver thermal power, the minimization of the relative LEC appears for low values of gross turbine power output but very high TES. This phenomenon, permits to work the turbine at design point conditions longer periods.

On the other hand, DSG technology provide theoretical/pre-commercial, high cost-less efficient (estimated 85% [45-46]) storage. With these assumptions, for a receiver thermal power, the minimization of the relative LEC occurs for high values of gross turbine power output but with low values of TES.

The importance of the location is clearly remarkable. For STPP which nowadays are not competitive with fossil fuel power plants, the development and construction of this CR efficient technology in countries of the solar belt with very high annual DNI as Carnarvon in South Africa (2995 $kWh/m^2/y$) and Daggett in United States (2791 $kWh/m^2/y$) would produce a relative LEC reduction of around 38% and 35% respectively for a MNS power plant. This LEC reduction combined with improvements in manufacturing and a more mature power tower industry (section 4.4) would make STTP with CR technology competitive in near future.

4.4. Case IV: Component's cost analysis

This study offers a component's cost analysis having into account the following assumptions:

- The location of Daggett is selected for the analysis because of its importance in the development of STPP with CR technology,
- Three receiver thermal power (270, 390 and 500 MW_{th}) are analyzed,
- The net annual energy is that obtained for the selected location in section 4.3.2,
- It has been used the consensus values of costs presented in Table X, that are believed to be plausible due to the improvements in manufacturing, a more mature power tower industry and an improved economy of scale.

Table X. Costs assumed to be applicable for future generation power plants [9]:

Land	2 €/m^2
Solar Field	120 €/m^2
Reference Solar Receiver	170 €/kW_{th}
MNS Thermal Storage	25 €/kWh
PCM Thermal Storage	30 €/kWh [36]
Reference Power Block	800 €/kW_e
Steam Generator	250 €/kW_e
Fixed Operation & Maintenance	50 €/kW_e/y

The results of this analysis are presented in the following sub-sections which describe different aspects related to relative LEC tendencies and cost reduction associated to the advances obtained in industry. The analysis is applied to the three cases for both DSG and MNS that minimize the relative LEC in Daggett for each receiver thermal power in section 4.3.2.

4.4.1. Relative LEC tendencies

Fig. 18 depicts the impact of the expected costs goals over the relative LEC for the reference power tower plant and for three power tower plants with MNS and DSG technology.

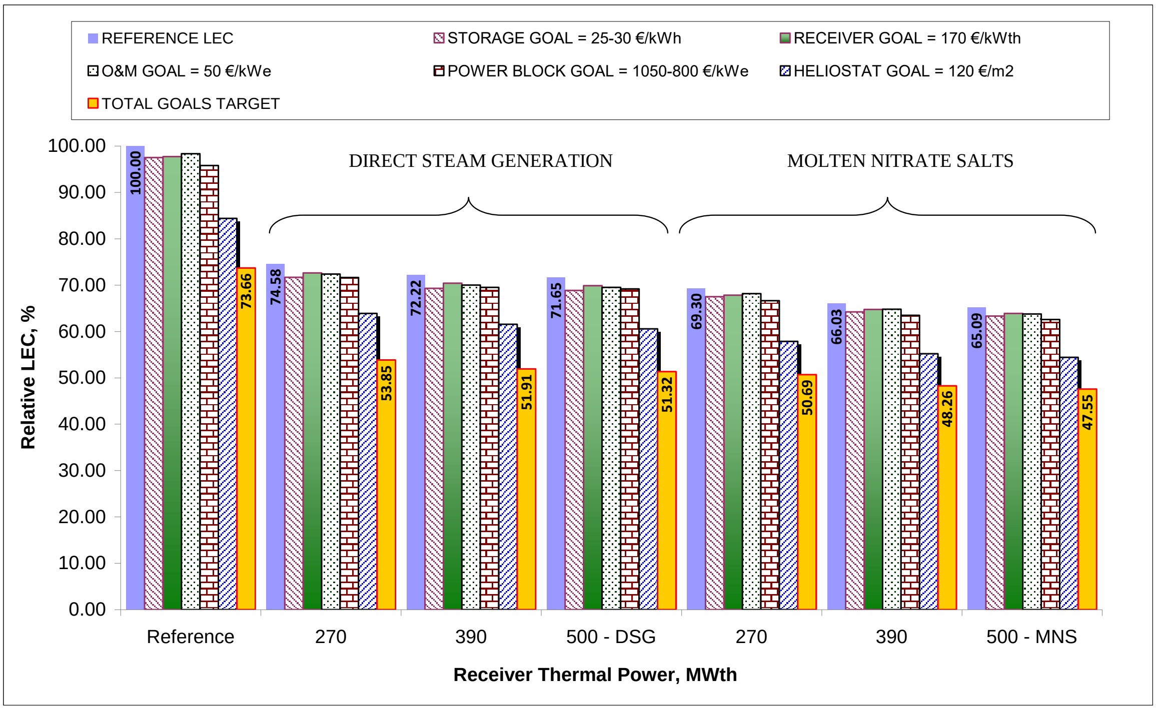

Fig. 18. Relative LEC for different sub-systems improvements over a STPP with MNS and DSG technology in Daggett

Nowadays, the relative LEC in Daggett for:

- DSG varies between 74.58% (270 MW_{th}) to 71.65% (500 MW_{th}) that can be reduced to 53.85% (270 MW_{th}) – 51.32% (500 MW_{th}),
- MNS varies between 69.30% (270 MW_{th}) to 65.09% (500 MW_{th}) that can be reduced to 50.69% (270 MW_{th}) – 47.55% (500 MW_{th}).

Fig. 18 shows the huge cost reduction potential that STPP with CR technology still has to go. A MNS system, located in Daggett, with 500 MW_{th} thermal receiver that accomplish with the cost that is assumed to be plausible in near future will reduce its cost by 52%, compare to the reference plant. For a DSG 500 MW_{th} thermal receiver, that reduction will be near a 49%. This would mean that STPP with CR technology could become an important source on the energy market without necessity of subsidies at all.

4.4.2. Cost reduction

Fig. 19 presents the impact of the different sub-systems analyzed over the LEC reduction. For this analysis a receiver thermal power of 500 MW_{th} is selected for both technologies.

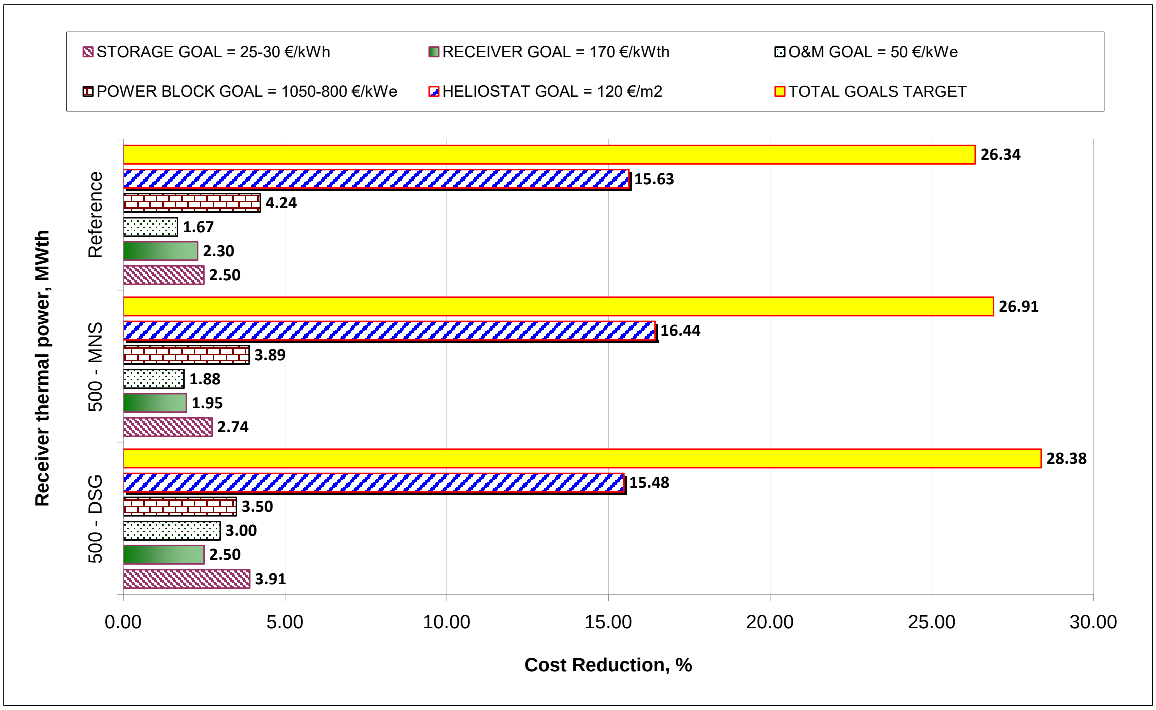

Fig. 19. Cost reduction for different sub-systems improvements over a STPP with MNS and DSG technology in Daggett

Fig. 19 shows that the higher LEC reduction (15-to-16%) is produced by the solar field. Moreover, O&M costs are related to the plant size, in such a way that the higher the power plant size is, the higher LEC reduction is expected. For a DSG system, the reduction due to the TES (3.9%) is much more important than for the MNS technology (2.7%). For the other sub-systems, the relative improvement is quite similar. The maximum LEC reduction after the combination of all the improvements is in between 25-to-30%. This target is expected to be achievable in future generation power plants with the assumptions considered in the analysis.

The cost reduction produced by the different sub-systems is quite similar for the three locations and receiver thermal power.

5. Conclusions

The paper presents an analysis for a medium to large size (290-to-500 MW_{th} receiver thermal power) CR plant considering the present market trends. The study is separated in four sub-sections:

- Size and location analysis: the main countries, nowadays, involved in the development of power tower plants are Spain, USA and South Africa. Therefore, this analysis was focused in three locations of these countries: Seville, Daggett and Carnarvon respectively. The comparison for a MNS CR technology with a receiver thermal power from 270 to 500 MW_{th}, presents an improvement in the LEC due to scale up the plant of 5.3% for Seville, 6.1% for Daggett and 5.6% for Carnarvon. Moreover, the analysis shows that for a similar power plant design, the net annual energy could be increased around 35%, from Seville-to-Carnarvon, whilst reduces the LEC around 28%. The LEC reduction from Seville-to-Daggett is 23%.

  With respect to the reference power tower plant (120 MW_{th}), this paper presents a scale-up factor of between 2.3-to-4.2. The relative LEC for a 500 MW_{th} receiver decreases for Seville, Daggett and Carnarvon by 11.3%, 32.4% and 36.1% respectively.

- Technology analysis: direct steam technology providers have marketed their solution as a practical, cost-effective method for system without storage. Therefore, in this sub-section the main technologies (DSG and MNS) without TES have been studied. It was concluded that a DSG system results in a lower LEC (100.51%) than a MNS system and a similar LEC (105.36 %) than the reference plant with 15 hours of TES (100%). Previous studies confirm this prediction [9].

- Storage analysis: when designing a thermal power tower plant, an important issue is to make the decision about the power of the turbine and the size of the thermal energy storage, once the receiver thermal power is selected. Consequently, this sub-section has simulated, for the two main technologies (MNS and DSG systems) and for the three selected locations (Seville, Daggett, Carnarvon), the impact of different combinations of thermal energy storage and power block sizes over relative LEC, for each optimized power plant.

  The outcomes reveal two main tendencies due to the importance of the thermal energy storage. MNS technology minimizes the relative LEC for low values of gross turbine power (33 to 78 MWe) and very high TES (14 to 16 hours). On the other hand, considering the difficulties to find out real information about TES costs for DSG, the LEC analysis has been carried out using the assumptions made in section 3.3 (PCM thermal energy storage: 50 €/kWh [34]). As a result, the relative LEC obtains its minimum value at high values of gross turbine power (67 to 122 MWe) and at low values of TES (2 to 5 hours).

- Component's cost analysis: market trends are focused on the specific cost reduction by means of larger plant size and through an improved economy of scale. Based on baseline cost parameters widely accepted in solar industry, an analysis over the specific costs of major components on the electricity cost has been carried out. For the analysis, the location of Daggett has been selected. The analysis was applied to the three cases for both DSG and MNS that minimized the relative LEC in Daggett for each receiver thermal power in section 4.3.2.

A MNS system, located in Daggett, with 500 MW_{th} thermal receiver that accomplish with the cost that are assumed to be plausible in near future will reduce the relative LEC by 52%, compared to the reference plant. A DSG with 500 MW_{th} thermal receiver the reduction will be near a 49%.

The higher LEC reduction is produced by the solar field sub-system by a 15-to-16%. For a DSG system, the reduction due to the TES (3.9%) is much more important than for the MNS technology (2.7%). For the other sub-systems, the relative improvement is quite similar. The maximum LEC reduction after the combination of all the improvements is in between 25-to-30%. This target is expected to be achievable in future generation power plants with the assumptions considered in the analysis.

Finally it can be concluded that this paper summarizes a variety of options for STPP with CR working with MNS and DSG. Nowadays these system are not competitive with fossil fuel power plants, but the research, development and construction of this CR efficient technology in countries of the solar belt with very high annual DNI as Carnarvon in South Africa (2995 $kWh/m^2/y$) and Daggett in United States (2791 $kWh/m^2/y$) would produce a relative LEC reduction of around 38% and 35% respectively. Furthermore, the combination of sunny countries, as Spain, with the improvements in manufacturing and a more mature power tower industry would make STTP with CR technology competitive in near future conducting to a LEC reduction due to these improvements of up to a 30%.

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