SIMULATION OF A CONCENTRATING SOLAR POWER PLANT FOR THE CHILE NORTHERN REGION

Humberto Vidal[1], Jaime Fernández[1] and Rodrigo Escobar[2]

[1] University of Magallanes, Department of Mechanical Engineering,

Punta Arenas, (CHILE)

[2] Pontificia Universidad Católica de Chile, Department of Mechanical and Metallurgical Engineering,

Santiago, (CHILE)

Abstract

The deployment of renewable energy power plants is a priority of the Chilean government. A mandatory quota system requires that 5% of the electricity generated in the country must come from renewable energy sources, gradually increasing to 10% by 2024. As of 2010, only wind and biomass power plants have been installed in the country, while solar energy has received attention only for small-scale future demonstration projects. Concentrated solar power (CSP) plants are an interesting option for the country, especially when considering the high levels of solar radiation coupled with high values of the local clearness index and availability of flat terrain that are available in northern Chile. In this work, the modeling and simulation of a 20 MW CSP plant of the parabolic trough type, without thermal energy storage is carried out. In order to maintain the power block performance at nominal conditions during long non-insolation periods, most of these plants have a thermal storage system or contain a heat support (such as fuel). Because of that, a proper solar field size, with respect to the electric nominal power, is a fundamental choice. A too large field will be partially useless under high solar irradiance values whereas a small field will mainly make the power block to work at part-load conditions. A sensitivity analysis is conducted in order to determine the influence of solar field area and radiation levels, and the optimal plant configuration and solar field area are obtained as a result. The CSP plant is simulated using the TRNSYS computational tool and monthly and annual electricity yields are obtained from hourly simulations that consider radiation levels, solar field, and power plant characteristics. Therefore, it was found that Chile has an outstanding potential for CSP plants, especially in the northern locations of the country such as Antofagasta.

1. Introduction

A government goal has been presented in order to promote and implement the measures needed to ensure that at least 15 percent of new power generation capacity installed between 2006 and 2010 in Chile was obtained from renewable energy sources (CNE, 2008). A new law has been passed, which requires electricity distributors to provide 5 percent of their energy sales from renewable energy sources, at average bided prices, increasing this contribution to 10 percent by 2024. This initiatives follow the so called 'short law' passed in 2004, which set standards and allowed small generators (< 20 MW) to connect to the national grids. The government hopes to promote the use of renewable energy for electricity generation, as a result of modifying the electricity sector law, effectively removing barriers for the incorporation of renewable energy plants.

In general, Chile is thought to be abundantly endowed with renewable energy but no large scale renewable energy resource assessment has been conducted, and in particular for solar. Therefore, any energy planning effort that considers this renewable source is seriously impeded for the time being. In the case of solar energy, large scale systems are not being planned or even discussed (Larrain and Escobar, 2009). Regarding the power generation sector, the solar thermal power plant technology is scarcely known. Solar energy development in Chile is small, mostly focusing on water heating applications for the residential sector. The market size is small, and solar power is used even more scarcely, mainly through photovoltaic panels in rural electrification. By the other hand, the energy consumption in northern Chile is mostly related to mining and industrial processes, which require continuous operation and energy supply. Therefore, it is presumed that solar as renewable energy source could be introduced to the *Sistema Interconectado del Norte Grande* (SING), that represents about a third of Chile's total electricity consumption, as a support to the conventional electricity generation system maintaining continuous supply of energy and power as needed. Therefore, Chile is an example of a country that could benefit from solar thermal power generation, as it exhibits both the need for electric energy and available solar radiation and associated climatic conditions, being better than in other locations where concentrated solar power systems are in use today. Yearly mean radiation reaches 6 kWh/m^2 in some regions in northern Chile (Ortega et al., 2009), and is higher than yearly mean radiation in some locations where CSP technologies are in use today, as for example in California, where it reaches 5.86 kWh/m^2, or Almeria, Spain, where values are near to 4.8 kWh/m^2. Also, northern Chile possesses ample plains and flat terrain availability with low alternative use, especially suited for large scale CSP deployment. Within solar power alternatives, the parabolic trough collector (PTC) power plant is currently the most mature and commercially available CSP technology (Sargent and Lundy, 2003) for solar electricity generation in Chile, since it displays better performance than other alternatives and also has the lowest energy generation cost of approximately 0.12 €/kWh (Kaltschmitt et al. 2007) that is becoming competitive with traditional power plants (Price et al., 2002; Sargent and Lundy, 2003).

Most of these plants consist of a solar field, a steam generator, a power cycle and a fossil-fuel fired backup system, as shown in Fig. 1. CSP plants either need backup auxiliary generation or storage capacity to maintain electricity supply when sunlight is low or not available. All commercially operated CSP plants are hybrid plants (Kearney and Price, 2004). They generally either have a natural-gas-fired boiler that can generate steam to run the turbine, or an auxiliary natural-gas-fired heater for the solar field fluid (Kearney and Price, 2004). This hybrid structure is an attractive feature of CSP compared to other solar technologies because the auxiliary backup component has a low capital cost and can mitigate intermittency issues to ensure system reliability. The addition of thermal storage would allow better use of available solar energy and would further reduce intermittency issues and potentially lower overall generation costs. However, the cost-effectiveness of adding solar storage depends on the tradeoffs between storage capacity, cost and other CSP system parameters. This technology uses parabolic trough shaped mirror reflectors to focus the sun's beam radiation on a linear receiver located at the focus of the parabola. A heat transfer fluid (HTF) circulates through the receiver and returns to a series of heat exchangers in the power block where the fluid is used to generate high-pressure superheated steam. The superheated steam is then fed to a conventional reheat steam turbine/generator to produce electricity.

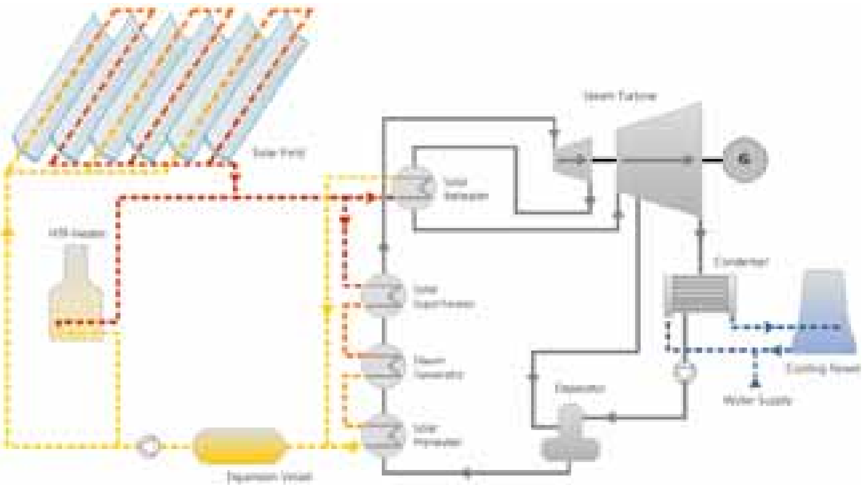

Fig. 1: Diagram of a solar thermal plant with parabolic trough system.

Patnode (2005) developed a computational model based in the SEGS VI plant, rated at 30 MW$_e$, with 188,000 m^2 and assembled in Kramer junction, (USA) in 1988. A model for the solar field was developed using the TRNSYS simulation program and the Rankine power cycle was separately modeled with a simultaneous equation solving software (EES). Both the solar field and power cycle models were validated with measured temperature and flow rate data from the SEGS VI plant from 1998 and 2005. The combined solar field and power cycle models were used to evaluate effects of solar field collector degradation, flow rate control strategies, and alternative condenser designs on plant performance.

Parabolic Trough plant projects with operational status

Nevada Solar One is a solar thermal plant, based on the parabolic trough collector (PTC) technology and is located in the El Dorado Valley in Nevada, USA. The solar field is made up of 760 solar collectors, each one with a reflective surface of 470 m^2, to make up a total of 357,200 m^2 of solar reflective field, over a total land area of 1,600,000 m^2. The steam turbine has a nominal generating capacity of 64 MW and the plant produces annually around 130 GWh (annual capacity factor of 23%), while employing a supplementary gas heater facility for back-up steam generation in case solar irradiation is not adequate. **The Alvarado I** plant is situated in Alvarado (Spain) and has a capacity of 50 MW, based on PTC technology. The facility is built on a 1 km^2 site with a solar annual potential of 2201 kWh/m^2, producing an estimated 105,200 MWh of electricity per year. The plant is made up of 768 solar thermal collectors, with an outlet temperature of 393°C, transferred with HTF: Biphenyl and Diphenyl oxide . **Andasol 1 and 2** are two identical solar thermal plants in operation since 2008 and 2009, respectively. These two 50 MW plants are located in Andalucia, Spain. The solar field of each of the Andasol plant has a total reflective area of more than 510,120 m^2 in a land area of 2,000,000 m^2. With an annual solar potential of 2201 kWh/ m^2 and the overall plant efficiency is around 16%. The Andasol plants are the first solar thermal plants to utilize two molten salt storage tanks for heat storage in cases of low solar irradiation. The molten salt storage tank system increases the annual equivalent full-load running time of the solar thermal plant to around 3500 h and have a storage capacity of 7.5 h at 50 MW. **Solnova 1, 3 and 4** are solar thermal plants located in Seville, Spain, and based on PTC technology. The plants use synthetic oil to generate high temperature steam and run a conventional steam cycle. The total reflective surface is composed of approximately 260,000 m^2 of mirrors. The total land area required for the Solnova 1 plant is around 1,200,000 m^2. Solnova 1 has an installed capacity of 50 MW and is capable of generating 114.6 GWh of electrical energy annually (annual average capacity factor of 26%). In low solar irradiation conditions, the plant is capable of supplying 12–15% of its capacity through natural gas combustion. The overall plant efficiency is estimated to be approximately 19%. Solnova 4 has the same features as Solnova 1 and 3 and consists of approximately 300,000 m^2 of mirrors that cover an area of about 115 hectares. **The Ibersol 1** plant is situated in Puertollano (Spain) and has a capacity of 50 MW, based on PTC technology. Ibersol 1 consists of 576 collectors arranged in 216 loops of four collectors per loop that cover an area of about 150 hectares. The total reflective surface is composed of approximately 287,760 m^2. Steam generation is achieved via the use of a HTF (thermal oil) and a thermal storage stage was also constructed, based on the technology of molten nitrate salt tanks. **Archimede** is a parabolic trough plant operating in Sicily, Italy. The plant produces steam 5 MW sent to a combined-cycle steam turbine rated at 130 MW. This parabolic trough system use molten salt as the heat-transfer fluid. Two tanks provide 8 hours of thermal storage. The solar field aperture area is about 31,680 m^2 over a total land area of 8 hectares. **The Florida** plant is situated in Badajoz (Spain) and has a capacity of 50 MW. This plant consists of 672 collectors arranged in 168 loops of four collectors per loop that cover an area of about 200 hectares. The total reflective surface is composed of approximately 552,750 m^2 of mirrors. Steam generation is achieved via the use of a HTF (Diphenyl oxide) and a thermal storage composed of 2-tanks based on the technology of molten nitrate salt tanks is used. Other plants assembled in Spain with operational status and 50 MW of capacity are: **Extresol 1 y 2** and **La Dehesa**, both located in Badajoz; **Majadas I** (Cáceres) and **Manchasol-1** (Ciudad Real).

2. The plant model

2.1. Power Plant

For the thermal solar plant simulation, a model that represents in the best possible way the running time of the solar field, as well as the power cycle or Rankine cycle was developed. The tool used for the simulation is the TRNSYS computational software (Klein, S.A., 2007), which allows an hourly simulation of the plant operation to study and analyze their behavior. For this it's necessary to establish design parameters in the configuration of each component that will work in the TRNSYS environment, specifically the components of the STEC library (Schwarzbözl, P., 2007). The power cycle is analyzed considering steady state, since the presence of an auxiliary heater ensures a certain working temperature of the oil at the inlet of the train of heat exchangers (Fig. 1), allowing no variations in the characteristic parameters of the power cycle. That way, the generated power will remain stable at 20 MW, established as the nominal power for the plant. These plants use a synthetic oil as HTF to transport heat absorbed in the collectors field and because of oil thermal stability, there is a maximum working temperature of 400 °C in the design of the power block, depending on the train of heat exchangers as heat source of the Rankine cycle. Thus, a design temperature oil of 390 ºC is established and, consequently, the temperature of the turbine inlet will be 380 ºC at a pressure of 80 bar. The turbine is considered with a high and low pressure body with reheating between, as well as three steam extractions, one at the high pressure body and two at the low-pressure body to provide energy to the feedwater heater systems of the Rankine cycle. These extractions are calculated in such a way that enthalpy drops be identical along the expansion turbine line. (Kostyuk and Frolov, 1988). The characteristics of these extractions are shown in Table 1.

Tab. 1: Main parameters value for the 20 MW$_e$ steam power cycle

Turbine	
Inlet pressure (bar)	80
Inlet temperature (ºC)	380
Outlet pressure (bar)	0.07
Isentropic efficiency, high pressure	0.85
Isentropic efficiency, low pressure	0.88
Steam generator efficiency	0.98
Reheater	
Inlet pressure, steam (bar)	20.5
Inlet temperature, oil side (ºC)	390
Outlet temperature, oil side (ºC)	290
Outlet temperature, steam (ºC)	380
Steam Generator	
Inlet pressure, steam water (bar)	80
Inlet temperature, oil side (ºC)	390
Outlet temperature, oil side (ºC)	290
Extraction no. 1	
Pressure (bar)	20.5
Temperature (ºC)	227.6
Extraction no. 2	
Pressure (bar)	4.82
Temperature (ºC)	223.1

Extraction no. 3	
Pressure (bar)	0.75
Temperature (ºC)	91.6
Condensate Pump (P1)	
Outlet pressure (bar)	4.8
Efficiency	0,9
Feedwater Pump (P2)	
Outlet pressure (bar)	80
Efficiency	0.9
Condensing Water Heater	
Terminal Temperature Difference (ºC)	1.5
Drain Cooling Approach (ºC)	5
Feedwater Heater	
Terminal Temperature Difference (ºC)	1.5
Drain Cooling Approach (ºC)	5
Deaerator	
Pressure (bar)	4.18

The condensing pressure is fixed at 0.07 bar and is referred to a water cooled condenser at a temperature of 20 °C. The feedwater heaters that work with extraction steam are surface exchangers and are defined by their terminal temperature differences. TTD (Terminal Temperature Difference) is the difference between saturation temperature at the extraction pressure and the water temperature at the heater outlet. DCA (Drain Cooling Approach) is the temperature difference between the cold water at the heater inlet and the subcooled steam at the heater outlet. In this work, the values assumed for TTD and DCA are 1.5 ºC and 5 °C, respectively. The heat exchangers train is divided into a steam generator and a reheater. The evaporation process is divided into three sections: phase change process from compressed liquid state, phase change from saturated liquid to saturated vapor and finally superheated vapor. Steam generator consists of a train of three counterflow heat exchangers: feedwater preheater, evaporator and superheater. The reheater accomplish the steam heating between the high pressure and the low pressure turbine in order to obtain an adequate expansion at a lower condensing pressure, avoiding the possibility of corrosion on the blades of the turbine through the final stages. In these exchangers only the evaporator has phase change on the cold side for the water/steam flow. The others work with single-phase fluids on both sides. The outlet oil temperature of the exchangers train will be considered at 290 ºC to obtain the main operating parameters. Figure 2 shows the power block scheme and Figure 3 shows the enthalpy-entropy diagram for the cycle.

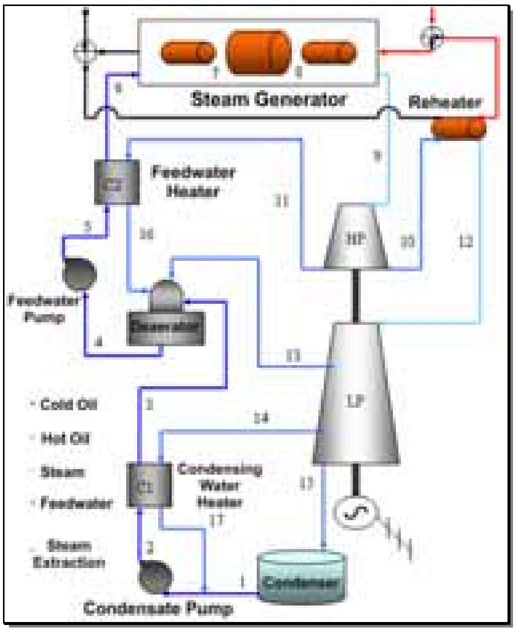

Fig. 2: Power cycle scheme

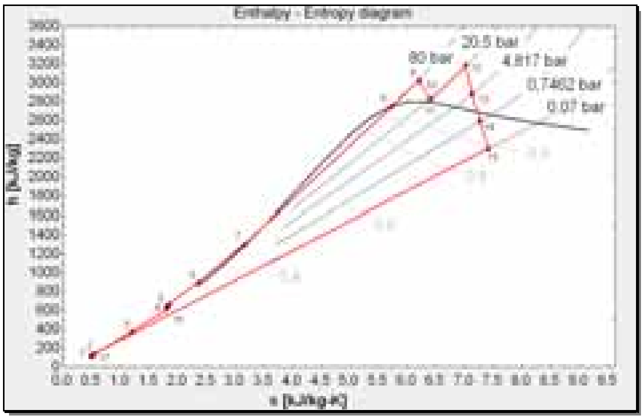

Fig. 3: Enthalpy-entropy diagram for the power cycle

2.2. Solar Collector Field

In order to have an appropriate thermal size for the collector array, as well as a proper overall solar field size related to nominal Rankine cycle thermal power, it is necessary to set a design point in which solar field performance is nominal (Montes et al., 2009). Commonly the chosen design point is noon on summer solstice (Casals, 2001) in which case for Antofagasta region is December 21st. The absolute maximum of radiation through the year should, in theory, be produced on this date and it should correspond to the minimum total surface of the collecting area.

There is a parameter that allows sizing the collector field and is known by the name of solar multiple. The solar multiple indicates the oversizing of the collector field in order to have an appropriate total area value to reach a radiation utilization maximum for a longer period through the day. The solar multiple is defined as the ratio between the thermal power produced by the solar field at the design point and the thermal power required by the power block at nominal conditions, as shown in the following equation:

$$SM = \frac{\dot{Q}_{field\_\max}}{\dot{Q}_{power\_cycle}} \qquad \text{(eq. 1)}$$

Depending on the type of plant there is a suitable solar multiple value for the sizing, which in the case of fossil fuel hybridization plants, a solar multiple of between 1 and 1.5 is recommended (Montes et al., 2009). The exact value in each case will depend on the nominal thermal power produced in the solar field and for this work a value of 1.2 is considered. The Figure 4 describes the concept of multiple solar.

The solar field has been designed to be used during daylight hours, however, it's use at times of acceptable solar radiation or above a minimum radiation value previously set is considerable. This is possible because the solar field has a natural gas auxiliary boiler, which provides support in times of low radiation.

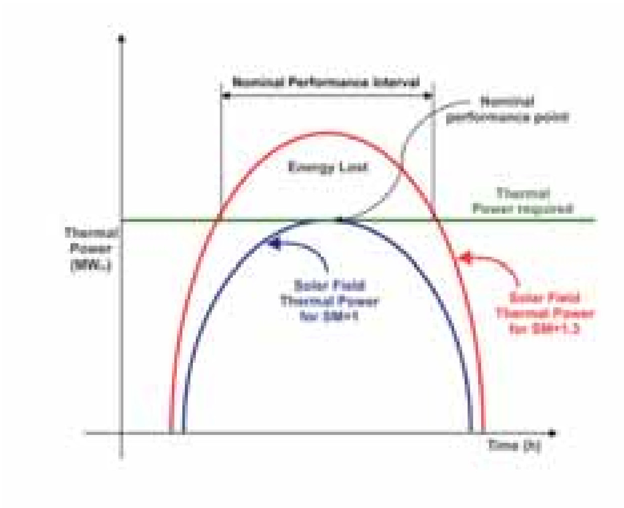

Fig. 4: Solar multiple concept.

To control the solar field operation, the oil mass flow must be handled in relation to how much is necessary to circulate through the collectors array, in order to ensure that the available radiation will be enough to achieve the demanded temperature in the exchangers train for the power cycle. Thus, there is a surplus of oil flow that's derived to an auxiliary boiler in parallel, so that the plant operates at all times with a nominal oil mass flow to produce nominal electrical power. The selected collector is an Eurotrough ET-150. The optical and geometrical characteristics are considered according to the requirements of the collector field model contained in the TRNSYS STEC library. In this work, two operation modes of the solar field are considered (fixed demand temperature and variable demand temperature on the outlet of the collector field), which will be discussed at the results section. Also, was necessary to consider a boiler at the outlet of the collector field to ensure the demanded temperature by the train of heat exchangers. In the variable demand temperature case two boilers are required while for the fixed demand temperature case at 390 º C it only requires the presence of a boiler in parallel. These considerations are used to create the Trnsys model and simulate these operating modes, ensuring the design temperature in the train of heat exchangers.

3. Trnsys Model

STEC library is a collection of TRNSYS models especially developed to simulate solar thermal power generation. It is a supplement to the standard TRNSYS routines featuring components from solar thermal power plants like concentrating collectors, steam cycles, gas turbines and high temperature thermal storage systems. The TRNSYS model of the solar thermal plant is composed. In the case of the main equipment of the plant, the STEC library is used. Control applications, processes and specific particular components, are provided by existing tools on the TRNSYS libraries. The model of the solar thermal power plant has three sections: solar field, heat exchangers train and power cycle.

3.1. Solar Field

The oil flows through the collector field, achieving the design temperature at the exit of the solar field and heading for the exchangers train. The model of the collector field requires a given oil flow, then the flow splitter located before the field, through a flow rate calculated between the field flow and the total flow, sends the required amount of oil to collectors. When the oil outlet temperature is higher than the design temperature, the tracking system of the solar field will activate the collectors defocus so they do not receive the full direct normal radiation. To simulate this behavior, knowing the exceeded temperature range the defocus thermal power loss is calculated. The balance of this loss to the net thermal power of the field will give us the effective value of captured heat and finally transferred to the oil thermal power. The collector field model requires the direct normal radiation data, ambient temperature and zenith and azimuth angles that describe the daily movement of the sun throughout the year. The direct normal radiation and the ambient temperature are provided by the Trnsys component called data reader. The sun tracking angles are calculated by the Trnsys's solar radiation processor, based on direct normal radiation.

3.2. Heat Exchangers Train

The oil flow enters to the superheater at 390 °C and exits at 290 °C at the preheater outlet, transferring the necessary energy to the power block's flow of water/steam. The water flows in the opposite direction of the oil on the cold side of the exchangers, is preheated, evaporated and superheated up to the required design conditions of 380 ºC and 80 bar at the turbine entrance. The reheater operates with the steam coming from extraction produced in the high pressure stage and returning to the low pressure stage at 380 ºC at the given pressure. Oil operates in the same conditions as in the steam generation section.

3.3. Power Cycle

The model considers the two bodies of the turbine, high pressure body and the low pressure body, the latter with its respective stages. The extractions are simulated with a steam flow splitter that uses a proper division for the operation of the heaters. The last extraction works with the demanded flow by the first water heater. Finally, there are two pumps, one for condensate and the other for feedwater.

3.4. Weather Data

For TRNSYS simulation, a weather database for the region where the solar plant will be assembled it's necessary. This requires the use of a weather database type TMY, representative of at least 10 years of weather data. To perform the simulation is considered an hourly weather database for the Antofagasta region, provided by Chile's Meteorological Office. For the simulation, the most important values are normal direct radiation value and ambient temperature, variables required by the TRNSYS model of the collector field.

Tab. 2: Solar multiple and flow mass depending on the collector area

Loops	Total area (m^2)	Oil flow per loop (kg/s)	SM
42	137,340	5.36	1.86
40	130,800	5.63	1.78
38	124,260	5.92	1.69
36	117,720	6.25	1.61
34	111,180	6.62	1.52
32	104,640	7.03	1.44
30	98,100	7.5	1.35
28	91,560	8.04	1.25
26	85,020	8.65	1.17
24	78,480	9.38	1.08

4. Simulations and Results

In a first instance, the analysis of the simulations will focus on finding the theoretical optimal area of the solar field. The fundamental concept that defines this area is the solar multiple resulting for each case, using as reference value for this type of plant an optimum value of 1.3 (Casals, 2001). After selecting an area, the next step is to analyze the plant considering the operation only through daylight hours. The analysis is performed taking into account a fixed demand temperature of 390 ºC at the outlet of the solar field and a variable demand temperature distribution, that depends on available radiation, which is shown in Figure 5.

4.1. Theoretical Optimal Total Area for the Collectors Field

The variation of the collector area is performed based on the loops number of the solar field area. Table 2 presents the results of oil mass flow per loop and solar multiple associated.

Based in the concept of solar multiple and considering the optimal reference value used in this work of 1.3, the theoretical optimal area for the collector field was calculated giving a value of 91,560 m^2, with an oil mass flow per loop of 8 kg/s and a solar multiple of 1.25.

4.2. Different operating conditions of the solar plant

Fixed Demand Temperature of 390 °C. This case corresponds to operate under the condition of a temperature of 390 ºC in the outlet of the collector field, throughout daylight hours. The system will be controlled under this condition, so that if the demanded temperature is not guaranteed by the available radiation, the plant should stop functioning.

Variable Demand Temperature. The solar field operates according to a temperature distribution of hourly demand and a minimum value of 345 W/m^2 of radiation. The distribution of demand temperature was determined based on maximizing the mass flow of oil to the solar field. This distribution of demand temperature was determined by the designed day mentioned above.

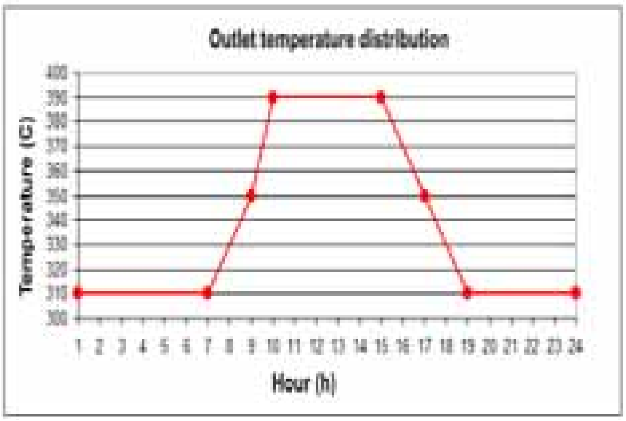

Fig. 5 Demanded temperature distribution for the collector field

4.2.1 Comparative Analysis

The comparison was done for both cases and the following plant variables: auxiliary thermal energy, net electrical energy and efficiency of the collector field. The results are graphically shown in Figures 6, 7 and 8.

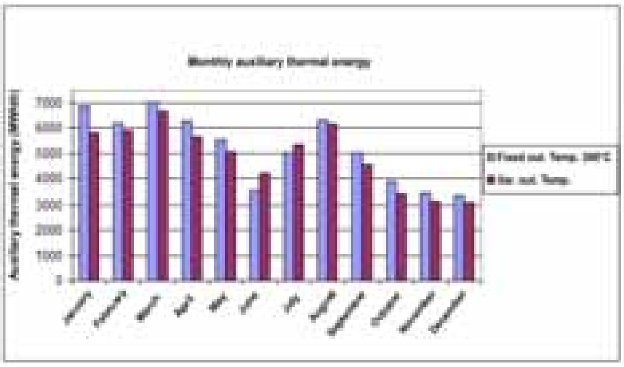

Fig. 6: Monthly auxiliary thermal energy

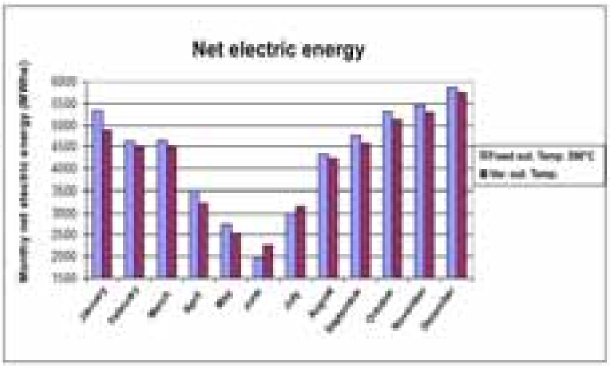

Fig. 7: Monthly net electrical energy

Figure 6, shows that the auxiliary consumption is lower when the plant operates on variable demand temperature than when is operating at a fixed temperature demand. However, for the months of the year with less radiation (June and July), the auxiliary consumption is higher because the plant operates with this type of energy for more hours during these months. The auxiliary energy supply in the operating mode with fixed demand temperature is of 48.2% and for variable demand temperature the auxiliary energy decreases 46.8%.

Conversely, Figure 7 shows that the net electricity production decreases when using a variable demand temperature, due to the plant operates under the constraint of minimal radiation, with the exception of the months of June and July.

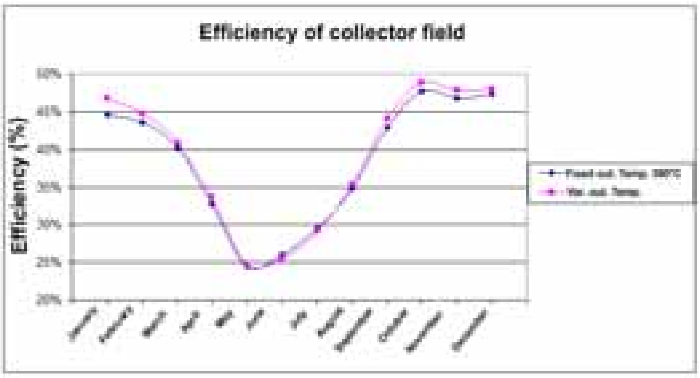

Fig. 8: Efficiency of the collector field

Figure 8, shows that the efficiency of the collector field increases, consequently does the plant efficiency for the case of variable temperature, allowing the collector field to operate with greater oil mass flow therefore will provide a greater heat transfer to the oil.

4.3. Hourly simulation results of the solar thermal plant

The results of the annual plant efficiency given by the TRNSYS simulations are presented through graphs representing the hourly behavior of the most important variables of the plant. The operating conditions correspond to the case of variable demand temperature for the outlet of the collector field and the operation in daylight hours, with restriction of 345 W/m^2. As shown in Figures 9 and 10, hours of operation increased in December compared to May the demand temperature for the collector field remains for more hours throughout the day. The extensive variation in the oil mass flow corresponds to the yearly radiation, resulting in lower values in May and higher values in December. This is due to the operation of the collector field under a variable mass flow to ensure the increasing of temperature from 290º C to 390 ºC.

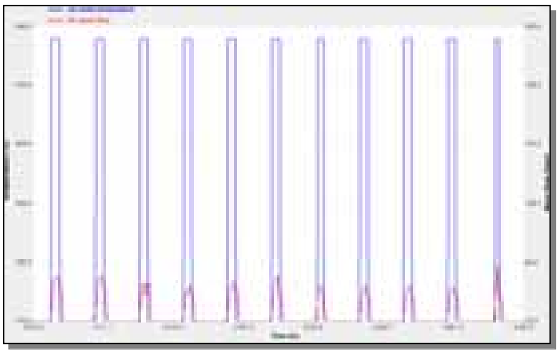

Fig. 9: Behavior of outlet temperature of the collector field and oil flow from May 8 to May 14

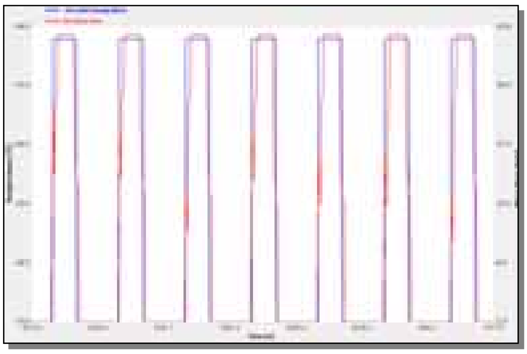

Fig. 10: Efficiency of outlet temperature of the collector field and oil flow from December 8 to December 14

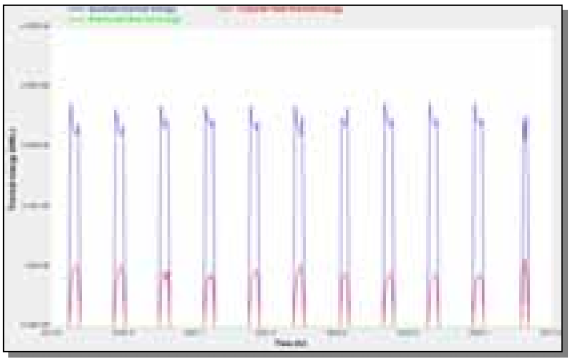

Fig. 11: Behavior of the net absorbed thermal energy, auxiliary and unfocused, from May 8 to May 14

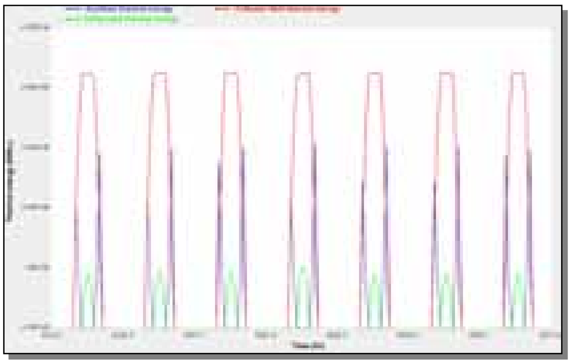

Fig. 12: Behavior of the net absorbed thermal energy, auxiliary and unfocused, from December 8 to December 14

Figures 11 and 12, show the behavior of the energy input, both of the collector field and the auxiliary system. Absorbed thermal energy is greatly increased in December compared to May and the opposite occurs with the auxiliary support. Table 3 gives a yearly overview of the main parameters that define the operation and production of the plant.

Tab. 3: Yearly Balance of the solar thermal plant

Global values of the Solar Thermal Plant	
Collector field area (m^2)	91,560
Number of collectors	112
Number of receiver tubes	4.032
Average annual radiation (W/m^2)	415
Average annual return, collector field	39.1 %
Efficiency, power cycle*	36 %
Average annual return, solar power plant	14.1%
Average annual solar fraction	48.8%
Capacity factor	28.0%
Availability Factor	56.4%
Net annual heat energy absorbed (MWh_{th})	67,199
Annual unfocused thermal energy (MWh_{th})	2,060
Annual auxiliary thermal energy (MWh_{th})	59,060
Gross Electricity (MWh_e)	49,998

* Generator efficiency: 98%

5. Economical analysis

Once annual electricity production and auxiliary consumption is estimated, an analysis may be performed to calculate the cost of the kWh_e associated to the plant. This value is called *levelized cost of energy* (LCOE) and is determined by Eq. (2):

$$LCOE = \frac{fcr \cdot C_{invest} + C_{OM} + C_{fuel}}{E_{net}} \qquad \text{(eq. 2)}$$

where *fcr* is the annuity factor; C_{invest} is the total investment of the plant; $C_{O\&M}$ represents the annual operation and maintenance costs; C_{fuel} is the annual fuel costs; and E_{net} is the annual net electric energy produced. To calculate the involved costs in Eq. (2), the data has been set according to (Montes et al., 2008) and these are shown in Table 4.

Tab. 4: Costs data and economical parameters for parabolic trough plants analysis.

Investment	
Solar field (US$/m^2)	267
Power Block (US$/kW$_e$)	982
Preheater (US$/kW$_e$)	2
Evaporator (US$/kW$_e$)	15
Superheater (US$/kW$_e$)	2
Reheater (US$/kW$_e$)	6
Construction, engineering and Contingencies	20%
Operation and maintenance	
Labour cost per employee annual (US$/year)	67,334
Number of persons for plant operation	30
Number of persons for field maintenance	10
O&M equipment cost percentage of investment per year	1%
Financial Parameters	
Annual insurance cost	1%
Lifetime (years)	20
Debt interest rate	7%

Tab. 5: Cost data of investment, operation and maintenance.

Investment	US$
Solar field	24,403,444
Power Block	19,639,018
Preheater	43,206
Evaporator	293,182
Superheater	45,591
Reheater	118,423
Construction, engineering and contingencies	8,908,573
TOTAL investment	53,451,437
Operation and maintenance	
TOTAL operation and maintenance	2,693,361
TOTAL solar thermal plant	61,197,830

Table 5 shows fixed costs investment and maintenance and operation costs. These costs are considered with the same value for all cases. The LCOE determined with the evaluation of the annual electricity production is 0.29 US$/kWh$_e$, corresponding to 44,998,036 kWh$_e$ of electrical energy production and an auxiliary energy annual consumption of US$ 5,328,761 using natural gas as backup fuel.

6. Conclusions

The model built complies with the basic operating parameters of the plant, which correspond to the continuity of the variable oil flow through the collector field, designed up to a maximum of 225 kg/s, calculated for the heat exchangers equipment of the power block and a leap of 100 °C, from a minimum demanded temperature of 290 ºC and maximum demanded temperature of 390 ºC for the collector field. With the consistency of these data in the simulation, the power block works within the boundaries of the design parameters at steady state throughout an entire year of operation, generating a nominal power of 20 MW$_e$.

The simulations showed that the collector area of the plant corresponds to a value of 91,560 m^2, size that was obtained by using the suitable solar multiple for this type of solar thermal power plant of 1.2. With this collecting area size other plant operating parameters were corroborated such as a capacity factor of 28% and operation hours of over 2,000 hours for a plant like this.

Comparisons between temperature modes demanded at the outlet of the collector field managed to show a reduction in the auxiliary support is achieved by varying the demanded temperature in the collector field. This is due to that when the day's radiation is less and lower than a demand temperature of 390 ºC, the oil mass flow to the collector field is maximized, thus reducing the flow to the auxiliary boiler and, hence, the auxiliary thermal energy delivered.

The LEC economic indicator gave values higher than those estimated from a CSP plant without thermal storage for today and the future 0.10 US$/kWh (Greenpeace, 2007). This price increment depends largely on the excessive use of auxiliary support for production, according to the imposition of nominal power to produce and also the more expensive value of natural gas at 1 US$/m^3 for the north of Chile, compared with other countries like Spain, where the value is about 0.30 US$/m^3 (Montes et al., 2009).

Although the characteristic values obtained for the solar power plant analyzed in this paper are those of a solar thermal plant of the same type located in the United States and Spain, these are achieved in a large percentage by the supplied auxiliary support of 46.8%. Countries like the U.S. and Spain that have such plants operating today have very strict regulations regarding the use of fossil fuel by allowing only 25% in California, United States and from 12% to 15% in Spain, according to the size of the plant.

A clear solution to reduce fossil fuel consumption, but affecting the production of electricity, is to consider in the designed model a partial load operation of the plant, with only one boiler in series with the collector field, therefore eliminating the parallel auxiliary consumption by oil mass flow diverted. This would, consequently imply a decrease of the annual production of the plant, but a more adequate solar/auxiliary relation of the plant. Another solution to reduce fossil fuel consumption and maintain the electrical power generated is the addition of a thermal storage system which supplies the auxiliary consumption and, depending on the amount of hours stored, extend the plant's daily operation period growing its productivity and the plant factor.

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