Analysis and optimization of concentrated solar power plant for application in arid climate

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Abstract
In this research study, the concentrated solar power (CSP) technology is reviewed for designing and optimizing a CSP tower plant for arid climate regions such as Qatar. A database for all CSP projects around the world is created, and a spreadsheet model for calculating the available solar irradiance is developed. Two software packages are used for analyzing and optimizing the entire solar thermal plant and its cost, SolarPILOT, and System Advisor Model (SAM). Both packages are validated using data from a recent power tower project. A thorough iterative optimization process was developed and applied to optimize the solar field parameters of a suggested CSP plant including tower optical height; heliostat structure width and height; number of heliostats; horizontal and vertical panels; receiver height and diameter; water consumption; cleaning schedule; maintenance; and total cost. The results confirmed the feasibility of a CSP plant on 0.45 km² of a solar field area with 2736 heliostats that produce 8 MWₑ with 10 hours of thermal storage and hybrid steam condensing system. It has been found that the highest production of the plant is in July, which is 3 621 950 kWh and the highest excess of electrical energy is in March, which is 2 946 965 kWh.

KEYWORDS
arid climate, concentrated solar power, heliostat structure, solar irradiance, SolarPILOT, tower optimal height

1 | INTRODUCTION

Most of the global energy is produced from fossil fuels, and only about 10% is produced from renewable resources.¹,² The Gulf Cooperation Council (GCC) countries, including Qatar, are considered the world’s largest hydrocarbon producing countries that hold a third of proven crude oil reserves and approximately a fifth of global gas reserves.³ Currently, these countries have less than 300 MW energy produced from renewable resources.⁴ Qatar is located within the Sun Belt region of the world, which receives abundant solar radiation. Qatar possesses relatively huge amount of oil and natural gas reserves. In 2020, Qatar’s population reached 2.874 million with CO₂ emissions of about 35.73 ton CO₂/capita and electrical consumption of 16 736 kWh/capita. The CO₂ emission is almost 8 times the world average of 4.47 ton CO₂/capita.⁵ In renewable side, Qatar possesses a total renewable energy installation of 28 MW. Moreover, in December 2012, the Sahara Forest Project (SFP) Pilot Facility in Qatar was commissioned and started its operation.⁶ This facility includes photovoltaic solar power panels and CSP. The renewable
energy production target of Qatar by 2030 is 1800 MW, which accounts for 20% of consumption. In addition to that, Qatar plans to build around 1000 MW of solar power generating capacity. Thus, the main goal of this paper is to analyze and optimize a CSP system to supply electricity to key locations in Qatar.

1.1 Introduction to CSP

As of 2016, according to Solar Power and Chemical Energy Systems, CSP market has a total capacity of 8784 MW, worldwide, among which 4815 MW is operational, 1260 MWe is under construction and 2709 MW is under development. Unlike solar photovoltaics (PV), only the direct solar radiation is used. The technical potential of generating electricity based on CSP is typically several times greater than their electricity demand, resulting in opportunities for electricity export. In CSP technology, mirrors or reflectors are used to concentrate the direct component of the sunlight onto a receiver or absorber that gathers and transfers the concentrated solar energy to a heat transfer fluid (HTF). This fluid transfers the collected energy to an application that utilizes the energy directly in the power cycle (gas/steam) or circulates it in an intermediate secondary cycle to produce electricity through conventional steam turbines or other technologies.

In parabolic trough technology, the concentration of the solar irradiance on the receiver can reach up to 70-100 times the originally received solar irradiance on the reflector with annual solar-to-electricity conversion efficiency of 15%-16%. A solar tower system uses a large field of flat mirrors that track the sunlight from a stationary point known as heliostats. These mirrors focus and concentrate the received sunlight onto a receiver on the top of a tower. With the current maturity of the technology, the maximum thermal power produced is limited to about 600 MW with heliostats that are located about 1.5 km from a tower of about 160 m height. Due to the huge solar field and the relatively small receiver of this technology, high concentration factors up to 1000 can be achieved and annual solar to electricity conversion efficiency of 15%-17% can be achieved.

1.2 Main components of CSP system

CSP system has four major components: solar collector, solar receiver, heat transfer fluid and energy storage, and finally power block. The solar collector receives the sun rays and directs them toward the absorber part of the system. The collector can be a trough with a 2-dimensional parabolic shape, a 3-dimensional dish, and two-axis tracking heliostats or linear Fresnel with one axis. In the initial days of receiver research and development, the main attention was on tubular designs, and currently, the attention is given to the development of volumetric receiver designs. In tubular design, the temperature of the tube body is always higher than the temperature of the heat transfer fluid. This limits the maximum operating temperature as in Solar One project and SOLOGATE. The SOLar Hybrid power and cogeneration plants (SOLHYCO) tubular cavity design is relatively recent design. This system is established on a 100 kW micro turbine with a fluid outlet temperature of around 800°C.

1.3 Heat transfer fluids (HTFs)

The heat transfer process is important to optimize in CSP applications through careful considerations of the process and the HTFs. The preferred characteristics of a typical HTF include low melting point, high boiling point and thermal stability, low vapor pressure at high temperature, low corrosion, high product of specific heat and density for energy storage, low viscosity, high thermal conductivity, and low cost. HTF can be classified into six main groups: (a) air and other gases, (b) water/steam, (c) thermal oils, (d) organics, (e) molten salts, and (f) liquid metals. Air as HTF is used in large CSP plants; however, Cinocca et al. proposed using air as HTF with a series of interheating and intercooling reaching a 20% global efficiency. The use of water/steam as both HTF and working fluid in the power cycle simplifies the system and ends up with improved efficiency and cost reduction. This HTF is used currently in the Ivanpah solar power facility that was launched in 2014. Other examples include four plants in Spain (Puerto Errado 1, PS10 solar power tower, PS20 solar power tower, and Puerto Errado 2) and three in California, USA (Kimberlina solar thermal energy plant, Bakersfield, Sierra sun tower, Lancaster and Ivanpah solar power facility, Ivanpah dry lake). Another one is the 50 MW Khi Solar One (KSO) solar thermal power plant, which is located in the Northern Cape Region of South Africa. However, the system requires extra effort to control due to the phase-change phenomena of the water and steam in the receiver. Synthetic oils, silicone oil, and mineral oil have been used as HTFs in CSP plants. Examples are the Andasol-3, Helioenergy, Aste, Solacor, and Solnova plant in Spain using parabolic trough collector. Cost wise, these thermal oils are expensive. Molten salts have properties similar to water at high temperature including similar viscosity and low vapor pressure. Most of the used salts solidify at temperatures below 220°C, which requires external heating to prevent solidification. In addition, molten salts are corrosive and react with air and water if leakage occurs. Innovative systems include the THEMIS tower (2.5 MWe) in France and Molten Salt Electric Experiment (1 MWe) in the United States. Solar salt, NaNO₃ (60 wt%)–KNO₃ (40 wt%), and Hitec salt are used in many modern CSP systems. Moreover, as one of the major problems is the lack of water in desert regions CSP plants, some
researchers investigated the feasibility of dry-cooling system with phase-change material (PCM), storage to store some of the latent heat of steam condensation during the turbine operation and reject it at night.

1.4 | Thermal energy storage

Currently, thermal energy storage technology integrated into the parabolic trough and power tower plants is the two-tank sensible energy storage using a molten salt of sodium nitrate and potassium nitrate (60-40 wt %). It was reported that at the Solar Two power tower project demonstration, the energy efficiency could achieve up to 98% for the storage system. The range of the operating temperature of the storage system depends on the solar field technologies used. The current parabolic trough and power tower technology can provide HTF at temperatures of 393°C and 565°C, respectively. That results in a storage temperature range of 292-385°C and 290-565°C, respectively. Higher operating temperature will increase the overall solar-to-electricity efficiency, reduce thermal storage volume, and decrease the levelized cost of electricity. Thermal storage can considerably improve the capacity factor of the power plant and its dispatchability. The Solar Multiple (SM) (ratio between the thermal power produced at the design DNI and the thermal power required by the power block at nominal conditions) normalizes the size of the solar field to the power block of the plant. Currently, plants with no thermal storage have a SM between 1.1 and 1.5 while plants with thermal storage may have solar multiples of 3-5.

1.5 | Power cycle

There are mainly three thermomechanical cycles that are being implemented with solar thermal power technologies. These are Rankine cycle, Brayton cycle, and Stirling engine systems. For Brayton cycle, a gas fuel backup system is recommended for system control purposes. The Stirling cycle is being used for small module engines for dish solar systems. Due to the achieved high process temperature using this cycle, the small size applications have high efficiency.

2 | LITERATURE REVIEW

2.1 | CSP plants

Currently, one of the most complete data source about the CSP plants in the world is the SolarPACES program with Stan’s Solar & Electrical LLC. The available data include CSP projects around the world that have plants that are either operational, under construction, under contract, or under development. The total number of projects categorized by project name is 153 in 23 different countries from all over the world. Of these 153 CSP projects, 109 are with working power plants, 16 are currently under construction, 12 are currently under development and 15 are currently nonoperational. In this study, all this information for all CSP projects was compiled and grouped for the ease of searching and comparing between different projects.

In Figure 1, the total number of CSP plants installed per country is illustrated. Spain has the highest number of CSP plants installed of more than 50 plants, then United States in the second place having 40 plants, and China in the third place with more than 20 plants. Parabolic trough technology is the highest technology that is used with 67% of utilization and 112 plants. This is because the parabolic trough technology is the most mature among the CSP technologies, and it is commercially proven. The power tower technology comes in the second place with 21% and 35 plants. It is worth to mention that power tower technology is the future trend of CSP technologies due to its higher efficiency, heat transfer fluid’s temperature, and concentration ratio compared to other technologies. Then, the linear Fresnel reflector and the dish engine come in the third and fourth place.

The total number of operational plants is 182 (73%), while 40 plants are under development (16%). The third highest percentage is the plants that are under construction and 3 plants only are nonoperational and under contract. Nearly half of the installed CSP capacity is with thermal storage. More than 80% of the capacity under construction has energy storage, and the majority is with molten salt storage technology. This percentage increases to 88% in trough and tower systems, while the current thermal storage technology used in linear Fresnel plants is a short-term pressurized steam storage of less than an hour.

2.2 | Annual solar-to-electricity efficiency

A significant parameter to evaluate a CSP system is the annual solar-to-electricity efficiency. In the current industrial
CSP plants, tower systems with molten salt as both the HTF and the storage material are the most efficient option with annual efficiency of 17%-18%. On the other hand, the lowest among those technical options is the annual efficiency of linear Fresnel systems with saturated/superheated steam, which is 9%-13%. The tower systems can have higher efficiency and is expected to increase from the current 18% to above 23%. This can be accomplished using supercritical carbon dioxide as the working fluid and using pressurized air as the HTF to drive a combined cycle plant. However, both systems are still at early stage of development.

### 2.3 Software packages

Several software packages have been developed for analyzing and optimizing either the entire solar thermal plant or only the heliostat field. Examples of these software packages are HFLCAL (for layout and optimization of heliostat fields), DELSOL3 (calculates collector field performance and layout and optimal system design), CAMPO (for collector field design), SolTrace (models CSP systems and analyzes their optical performance), SAM (models CSP systems and calculates financial metrics), and SolarPILOT (generates and characterizes power tower systems). Although some software packages allow the user to specify the solar field layouts, their optimization capabilities are restricted to cornfield or radial staggered layouts. In the present study, the optimization methodology is rather thorough and addresses those and other restrictions of the optimization capabilities of the existing software packages. SolarPILOT software package (version: 2017.2.7) is used in the present study, which is an integrated layout and optimization tool for solar power towers capable of designing and optimizing the solar field layout of the plant. Then, the final design values are inserted in SAM software package for designing and optimizing the entire solar plant from a financial and technical point of view.

SolarPILOT is developed by the National Renewable Energy Laboratory (NREL), and it generates and characterizes power tower systems only. SolarPILOT has implemented methods to reduce the overall computational efforts of the number of heliostats while generating accurate and precise results.

SAM is a performance and financial model designed to facilitate decision making for renewable energy sector. SAM makes performance predictions and cost of energy estimates for grid-connected power projects based on installation and operating costs and system design parameters. SAM calculates the cost and performance of renewable energy projects using computer models developed at NREL, Sandia National Laboratories, the University of Wisconsin, and other organizations. The models require input data to describe the performance characteristics of physical equipment in the system and project costs. Two of the main references that are used by SolarPILOT and SAM to determine the default values of CSP are.

### 3 VALIDATION OF MODELS

#### 3.1 Validation of solar insolation model

In the current study, a model has been developed to determine the hourly available solar energy per square meter on a horizontal, sloped, one-axis, and two-axis tracking surface in any location on earth. This model can find the optimum values of the controllable parameters that affect the capturing of the available solar energy. The model is based on the most accurate available relations for calculating available solar energy, and they have been tested and verified in. In the current study, the cloudy sky approach is used where the available solar energy at ground surface becomes a function of only the extraterrestrial radiation and the clearness index ($k_T$). The model uses the solar angles’ equations, the horizontal surface’s equations, the tilted surface’s equations, and the tracking surface’s equations to calculate the insolation available at a certain location at an average day of the month. The solar angles’ equations used in the model are those adopted from. The ratio of the diffused solar radiation to the total solar radiation is found as:

$$\frac{I_d}{I} = \begin{cases} 1.0 - 0.09k_T & \text{for } k_T \leq 0.22 \\ 0.9511 - 0.1604k_T + 4.388k_T^2 - 16.638k_T^3 + 12.336k_T^4 & \text{for } 0.22 < k_T \leq 0.80 \\ 0.165 & \text{for } k_T > 0.8 \end{cases} \quad (1)$$

At any point in time, the solar radiation incident on a horizontal plane outside of the atmosphere ($G_o$) is given by Equation (2). The value is then multiplied by the corresponding $k_T$ for the month to add the atmospheric effect.

$$G_o = Gsc \left(1 + 0.033 \cos \frac{360n}{365}\right) (\cos \varphi \cos \delta \cos \omega + \sin \varphi \sin \delta) \quad (2)$$

where $Gsc$ is the solar constant in W/m², $n$ is the day of the year, $\varphi$ is the latitude, $\delta$ is declination and $\omega$ is the hour angle.

The diffused solar radiation is found by multiplying the total solar radiation available by $I_d/I$, where $I$ is the intensity of radiation. The beam radiation component can be calculated from the ratio $G_b/TGb$ given by:

$$R_b = \frac{Gb,T}{Gb} = \frac{Gb,n \cos \theta}{Gb,n \cos \theta z} = \frac{\cos \theta}{\cos \theta z} \quad (3)$$

where $R_b$ is ratio of beam radiation on tilted surface ($Gb,T$) to that on horizontal surface ($Gb$), $\theta$ is the angle of incidence of beam radiation on a surface and $\theta z$ is the zenith angle.
A surface tilted at slope $\beta$ from the horizontal has a ratio of diffuse on the tilted surface to that on the horizontal surface $R_d = (1 + \cos \beta)/2$. The tilted surface has a ratio of reflective on the tilted surface to that on the horizontal surface $R_r = (1 - \cos \beta)/2$. If the surroundings have a diffuse reflectance of $\rho_g$ for the total solar radiation, the reflected radiation from the surroundings on the surface will be $I \rho_g (1 - \cos \beta)/2$. Thus, the total solar radiation on tilted surface as the sum of the three terms is given as:

$$I_T = I_d R_d + I_r \left( \frac{1 + \cos \beta}{2} \right) + I \rho_g \left( \frac{1 - \cos \beta}{2} \right)$$ (4)

Main modes of tracking considered in the model were full; E-W polar; N-S horizontal; and E-W horizontal. To compare the tracking modes, the total available radiation for horizontal surface, fixed slope surface, one-axis tracking surface, and two-axis tracking surface for each month of the year were calculated as shown in Figure 2. The two-axis tracking surface throughout all months has the highest monthly total available radiation. The one-axis tracking surface comes in second with almost 65% of the two-axis tracking surface output. The fixed slope surface receives less radiation than the horizontal surface on April to August.

The model was validated against actual data collected by QEERI, where a study was conducted for 6 years of ground measurements of the total solar radiation on a horizontal surface, collected by 12 automatic weather stations throughout Qatar. The monthly clearness index is presented for each location. The location is selected to be Qatar University with longitude of 51.49° E and latitude of 25.38° N. Based on the actual stations’ data, the year-to-year and monthly variations of daily global horizontal irradiation for each station, the average found to be 5.80 kWh/m²/d and a total of 2116 kWh/m²/y. The model predicted daily average horizontal irradiation of 5.8 kWh/m²/d and yearly average horizontal irradiation of 2120 kWh/m²/y. The results found by the model are very close to the actual results presented in and thus, the model is considered valid.

### 3.2 Validation of SolarPILOT and SAM

To validate SolarPILOT and SAM calculations, an already built solar power plant will be simulated and the results will be compared to the actual results of the plant. One of the newest solar power plants in USA is the Crescent Dunes Solar Energy Project in Tonopah, Nevada. It is a 110 MW plant with 10 hours of thermal storage that started its production in Sep 2015. It is the first utility-scale CSP plant with a central receiver tower and advanced molten salt energy storage technology from SolarReserve.

![Image](Crescent_Dunes_Tower.png)
3.2.1 SolarPILOT validation

SolarPILOT is mainly used to find the heliostat field including the calculation of the heliostat positions and optimal values for the tower height, receiver height, and receiver aspect ratio (height/diameter). The desired total power delivered by the receiver at the reference design point is given as:

\[ q_{sf, des} = q_{inc} \cdot \alpha - q_{hl}^e \cdot A_{rec} - q_{pipe} \]  

where:  
- \( q_{sf, des} \) (MW): Thermal power delivered by the solar field;  
- \( q_{inc} \) (MW): Thermal power incident on the receiver;  
- \( \alpha \) (-): Receiver surface absorptivity;  
- \( q_{hl}^e \) (kW/m²): Emissive and convective thermal loss;  
- \( A_{rec} \) (m²): Absorptive surface area of the receiver;  
- \( q_{pipe} \) (MW): Thermal loss due to riser/downcomer piping.

SolarPILOT offers several options for specifying the region of land where heliostats may be placed. One of the options is to use the land boundary array that specifies the area using polygonal shapes from Google Earth PRO as shown in Figure 3. After selecting the field area, the tower location is selected and imported to the land boundary array.

The solar field generated from the performance simulation is shown in Figure 4. The number of heliostats of the solar field found by SolarPILOT is 10,216 heliostats, which is only 1.3% less than the 10,347 heliostats of Crescent Dunes plant. Accurate results would be obtained considering the actual heliostat positions, and using power to receiver as validation parameter.

3.2.2 SAM validation

SAM makes performance predictions and cost of energy estimates for grid-connected power projects based on installation and operating costs and system design parameters. The heliostats positions of the solar field are exported from SolarPILOT and imported into SAM. The heliostats cleaning schedule is determined by studying the available cleaning schedules of the existing operational plants. Based on this, the average consumption of water per m² is taken as 0.7 L and the number of washes per year is 63 washes. An adjustment factor that takes into consideration reduction in energy output due to downtime of some heliostats in the field for repair, maintenance, or cleaning activity is considered. The site improvement cost is estimated to be 16 $/m². The heliostat field cost is estimated to be 145 $/m². The total tower cost is:

\[ \text{Total Tower Cost} = \text{Fixed Tower Cost} \times e^{(\text{Tower Cost Scaling Exponent} (\text{Tower Height} - \text{Receiver Height}/2 + \text{Heliostat Height}/2))} \]

The receiver cost is found as:

\[ \text{Receiver Cost} = \text{Receiver Ref. Cost} \times \left( \frac{\text{Receiver Area}}{\text{Receiver Ref. Area}} \right)^{\text{Receiver Cost Scaling Exponent}} \]

Other costs include thermal storage, balance of plant, power cycle cost, and a contingency of 7%. The total direct cost is found to be $540 million and the total installed cost is $664 million. In comparison, the US Department of
Energy has issued in Sep 2011 a $737 million loan guarantee to finance Crescent Dunes project.\textsuperscript{51} There is no further information about the breakdown of this loan. The difference between the calculated cost from SAM and the issued loan is less than $75 million. This difference can be attributed to unknown source of costs. The monthly energy production for the actual plant was compared to results obtained using SAM as shown in Figure 5. The annual energy produced by the plant is around 430,000 MWh, and the capacity factor is 49.6% with summer months having the highest production.

As mentioned before, the annual energy production of Crescent Dunes Solar Energy Project is expected to be 500,000 MWh. Compared to SAM result, there is a difference of 70,000 MWh, that is, SAM is less by 14%. Due to lack of actual performance information about Crescent Dunes Project, a final conclusion about validity of SAM result cannot be reached. However, based on the available information of the project, SAM is considered close to the expected annual energy production.

### 3.3 Electrical demand in key location in Qatar

To design the required capacity of the CSP plant, the electrical consumption data for more than 600 shops in key location in Qatar for the year of 2014 and 2015 is provided on monthly basis as shown in Figure 6. The maximum monthly electrical consumption occurred in September with value of 1,057,655 kWh. The maximum daily electrical consumption was found to be 36,754.23 kWh. The total averaged annual consumption is almost 8.7 GWh.

### 3.4 Selection of plant location

The plant should be close enough to the electrical consumption area to reduce the total losses in transmission and distribution. Al Safliya island is selected. It is 1.26 km\(^2\) in area and it is located around 25.345 degrees North and 51.577 degrees East, which is less than 8.5 km far from the electrical consumption area. The CSP plant will utilize only 0.46 km\(^2\) of the island total area as shown in Figure 7. Many solar power plants are built on islands, although clear justification was not found in literature for whether the reduction in turbidity of atmosphere due to dust is sufficient to counter potential salt spray onto heliostats. Examples of these plant built on islands are the plant built on Al-Farasan Island in Saudi Arabia,\textsuperscript{52} the one on the island of Annobón in Annobón Province\textsuperscript{53} and the plant on island of Kauai in Hawaii.\textsuperscript{54}
4 | RESULTS AND DISCUSSION

In this study, the weather file for Al Safliya island has the solar irradiance data (total global horizontal irradiance, total direct normal irradiance, and total diffuse horizontal irradiance) from the prepared Microsoft Excel model. The other weather data (dry-bulb temperature, relative humidity, atmospheric pressure, wind speed and direction) are taken from that was based on a satellite-based value measured for Doha International Airport in 2011. The wet-bulb temperature is generated from a Microsoft Excel program provided from www.the-snowman.com using the available dry-bulb temperatures and relative humidity values.

4.1 | Optimization procedure and SolarPILOT results

A robust optimization procedure has been conducted in this study via performing a parametric study to optimize the maximum production of the CSP plant by optimizing the parameters of the solar field. In other words, the objective function of the optimization is the maximization of the production of the CSP plant subject to the following constraints: limit of the available land; tower optical height; heliostat structure width and height; number of heliostat horizontal and vertical panels; receiver height and diameter; water consumption; cleaning schedule; and maintenance and total cost. The interdependency of the optimized parameters has been addressed by performing several iterations to reach optimized values as discussed in the following sections.

4.1.1 | Optimization of solar field parameters

Initial values for the solar field's parameters are assumed and then optimized later one by one. First, the land boundary array option is selected and the solar field area is chosen for the CSP plant. Second, the design point DNI value based on the weather file is taken as 700 W/m². Table 1 shows the assumed initial values.

For the first optimization iteration, the solar field design power will be changed until the heliostats fill the selected area. After many iterations, the initial optimum solar field design power is found as shown in Table 2. It can be noticed that as the solar field design power increases, all related performance parameters in Table 2 increase until a limit of the power absorbed by the solar field is reached. This limit is found at 55 MW of design power with absorbed power by the receiver of 58 171 kW.

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**TABLE 1** Initial values for solar field's parameters

| Parameter                              | Value |
|----------------------------------------|-------|
| Tower optical height, m                | 220   |
| Heliostats structure width, m          | 8     |
| Heliostats structure height, m         | 8     |
| Number of heliostat horizontal panels  | 2     |
| Number of heliostat vertical panels    | 8     |
| Receiver height, m                     | 3     |
| Receiver diameter, m                   | 10    |

**TABLE 2** Initial optimum solar field design power and related performance parameters

| Parameter                              | 54   | 55   | 56   |
|----------------------------------------|------|------|------|
| Solar field power, MWt                 |      |      |      |
| Performance parameters                 | 169 603 | 169 851 | 169 851 |
| Simulated heliostat area, m²           | 2732 | 2736 | 2736 |
| Power incident on field, kW            | 118 722 | 118 896 | 118 896 |
| Power absorbed by receiver, kW         | 58 110 | 58 171 | 58 171 |
| Power absorbed by HTF, kW              | 53 039 | 53 100 | 53 100 |
| Solar field optical efficiency, %      | 52.1 | 52   | 52   |

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**Optimization of tower optical height**

Tower height is an important parameter that will affect the layout of the solar field. As the tower height increases, the adjacent heliostats will have difficulty in directing the sun rays to the receiver and vice versa. In Figure 8, the relation between the power absorbed by the receiver vs the tower optical height is shown for the current simulation stage. The optimum tower height is found to be 150 m at which maximum power can be absorbed by the receiver, 63 863 kW. Thus, 150 m tower height is selected.

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**FIGURE 8** Power absorbed by receiver vs tower optical height
Structure width and height optimization

Another important parameter that affects the solar field reflective area and the count of heliostats is the heliostat structure width and height. For a fixed solar field area like the case of this CSP plant, as the area of a single heliostat increases the total number of required heliostats decreases and results in less separate cleaning activates and less number of mechanism components and control equipment. Different heliostat structure widths and heights vs solar field performance parameters were simulated as shown in Table 3. Decreasing the area of the single heliostat increases the number of the heliostats rapidly. This is accompanied with increase in all performance parameters mentioned. However, there will be a huge difference in the controlling system and the number of mechanisms required between, for example, 2736 heliostats in the case of 8 m by 8 m and 4985 heliostats in the case of 6 m by 6 m. Moreover, the difference in the solar field power for both cases is only 1 MWt which does not worth all the extra cost and the added complexity of the mechanism. Thus, 8 m by 8 m is selected.

Receiver height and diameter optimization

To find the relation between the receiver height and diameter and the power absorbed by the receiver, five different diameters (from 2 m to 6 m) against three heights (1 m, 2 m, and 3 m) for each diameter are studied as shown in Figure 10. As

Mean simulation results

| W x H     | 4 m x 4 m | 6 m x 6 m | 8 m x 8 m | 10 m x 10 m |
|-----------|-----------|-----------|-----------|-------------|
| Solar field design power, MWt | 60 | 56 | 55 | 54 |
| Simulated heliostat area, m² | 185 169 | 174 076 | 169 851 | 169 168 |
| Simulated heliostat count | 11 931 | 4985 | 2736 | 1744 |
| Power incident on field, kW | 129 618 | 121 853 | 118 896 | 118 418 |
| Power absorbed receiver, kW | 64 681 | 60 370 | 58 171 | 57 453 |
| Power absorbed by HTF, kW | 59 610 | 55 298 | 53 100 | 52 382 |

TABLE 3 Effect of heliostat structure widths and heights

FIGURE 9 Number of horizontal and vertical panels vs power absorbed by the receiver

FIGURE 10 Receiver diameter and height combination vs power absorbed by the receiver

Optimization of number of panels

Multiple panels of a heliostat are mounted on the heliostat structure at a preferred orientation to maximize the optical performance. A simulation is performed to reach the optimum combination number of both horizontal and vertical panels to produce the maximum power absorbed by the receiver and the results are shown in Figure 9. The results are found for all combinations from two panels up to six panels. The maximum power absorbed is at 2 and 2 combination; however, this option is not cost-effective and will have manufacturing difficulty. Moreover, large panels are very expensive to replace if cracking of the surface occurs. Thus, this combination is not recommended. All next combinations have the same power value, which is 58 031 kW. Any combination can be selected and thus, combination 5 and 4 is selected.

Receiver height and diameter optimization

To find the relation between the receiver height and diameter and the power absorbed by the receiver, five different diameters (from 2 m to 6 m) against three heights (1 m, 2 m, and 3 m) for each diameter are studied as shown in Figure 10. As
the diameter of the receiver increases, the power absorbed by the receiver increases and converges to a maximum value. This value is already reached with diameter of 6 m. Thus, there is no point of having more than 6 m diameter. Regarding the height of the receiver, as the selected height increases the power absorbed increases. The height of 3 m is the maximum height that can be chosen with diameters of 2 m to 6 m. The cost related to the receiver panels of any CSP tower is considered the most expensive component among the other capital cost items; thus, any reduction in the size of the receiver is recommended. The difference in the power absorbed between the receiver of 3 m height and diameter 6 m and diameter 5 m is less than 0.9 kW. Thus, the receiver with diameter of 5 m and height of 3 m is selected.

### 4.1.2 Summary of optimized parameters

Following the same steps done for the first optimized values, the final optimized values are found and tabulated in Table 4 along with the initial values and the first optimized solar field’s parameters. The tower optical height converged from 220 m to 140 m, which means that optimization steps converge toward the most optimal value. The number of heliostat of the optimized solar field, that is 2736, did not change from the initial value. The heliostats distribution with optical efficiency is shown in Figure 11. The nearest three rows of heliostats have less efficiency than the later rows due to the difficulty of controlling the aim point of the heliostat toward the receiver. The last rows have less efficiency due to optical losses from the relatively far distance from the receiver. The final optimized solar field design power is the highest and it is 61 MWt and this means 8 MWₑ estimated net output power at design. In Table 5, the final optimized solar field parameters are shown.

#### Table 4 Optimized vs the initial values of solar field’s parameters

| Parameter                      | Initial values | 1st optimized values | Final Optimized values |
|--------------------------------|----------------|----------------------|------------------------|
| Tower optical height, m        | 220            | 150                  | 140                    |
| Heliostat structure width, m   | 8              | 8                    | 8                      |
| Heliostat structure height, m  | 8              | 8                    | 8                      |
| Heliostat horizontal panels number | 2          | 5                    | 5                      |
| Heliostat vertical panels number | 8            | 4                    | 4                      |
| Receiver height, m             | 3              | 3                    | 3                      |
| Receiver diameter, m           | 10             | 5                    | 5                      |
| Number of heliostats           | 2736           | 2736                 | 2736                   |
| Solar field design power, MWt  | 55             | 60                   | 61                     |

F I G U R E  11  SolarPILOT final optimized solar field of the CSP plant
imported from SolarPILOT to SAM. The heliostat dimensions are the optimized results from SolarPILOT.

### Water demand and desalination requirements

The monthly total plant water requirement for steam cycle makeup, hybrid cooling, and heliostat washing activities are shown in Figure 14. The water consumption related to steam and hybrid cooling follows the temperature profile of the location, and it is maximum in July. Annually, washing activities consume around 15% only compared to steam makeup and hybrid cooling.

#### 4.2.2 Plant monthly energy production

The electricity production and consumption of the plant on monthly basis is shown in Figure 15. The highest production of the plant is in July, which is 3,621,950 kWh, and the highest excess of electrical energy is in March, which is 2,946,965 kWh. This excess of energy is assumed enough to provide electricity to Msheireb Downtown Doha zone that is still under construction. A degradation rate of 1% per year is assumed. The maximum production loss is at year 35 at 1,000,000 kWh/mo.

#### 4.2.3 CO₂ gas emissions reduction of the CSP plant

As discussed previously, the CO₂ gas emissions of the most efficient combined cycle gas turbine process are estimated by The Parliamentary Office of Science and Technology in London to be 200 g CO₂eq/kWh.56 Thus, multiplying this number with the energy produced by the designed CSP plant, the reduction in CO₂ gas emissions can be found for each month. The total CO₂ emissions for the current study was reduced by 7581 ton CO₂.

#### 4.2.4 System cost analysis

As mentioned in the validation section, the total system installed cost consists of direct capital costs, indirect capital

| TABLE 5 SolarPILOT results, final optimized solar field |
|-----------------------------------------------|
| Mean simulation performance parameters | Value |
| Solar field design power, MWt | 61 |
| Simulated heliostat area, m² | 156,255 |
| Power incident on field, kW | 109,379 |
| Power absorbed by the receiver, kW | 60,976 |
| Power absorbed by HTF, kW | 58,134 |
| Solar field optical efficiency, % | 59.3 |
| Optical efficiency incl. receiver, % | 55.7 |
costs, and operation and maintenance costs. The highest water consumption occurs on 8 June and it is 384 m$^3$. The cooling and makeup water consumption at that day is 265 m$^3$ and it is assumed that heliostats washing is done also on the same day. The maximum water consumption is thus approximated to be 400 m$^3$. The installed cost of a desalination plant is approximated to be $1 m for every 1000 cubic meters per day of installed capacity.57,58 Thus, the desalination unit cost is approximated to be $ 400 000. The heliostat field fixed cost is added. Based on the available operational experience for CSP plants, the lifetime of a CSP plant may be more than 30 years. In this paper, the lifetime of the CSP plant is selected to be 35 years. The degradation rate of the plant is assumed to be 1% each year up to the 35th year. The typical operating and maintenance expenses for a CSP plant include mirror washing, repair, and replacement and major equipment maintenance activities that are approximately done every 5 to 7 years. Most of the thermal solar operators treat operating and maintenance on a fixed basis that is $67.26/ kW-year. Considering a 3% per year inflation rate from 2013 to 2017, the fixed operating and maintenance expenses in 2017 is expected to be $75.70/kW-year. Moreover, the contingency cost is selected to be 7% of the subtotal cost of the direct capital cost. Total direct capital cost is found to be $ 73 395 696.

The total indirect cost of the plant is $ 10 674 192. Adding the direct and indirect costs, the total installed cost of the project is found to be $ 84 069 896. Thus, the estimated total installed cost per net capacity is $ 11 120/kW. The capacity factor of the plant is found to be 57.40% in year 1. For the real levelized cost, the real IRR is used and it is found to be 18.65 ¢/kWh. Similarly, for the nominal levelized cost, the nominal IRR is used and it is found to be 25.72 ¢/kWh. This levelized cost might be high compared to a PV system with battery storage that might be attractive for a small plant of 8 MW$^c$. However, PV systems with battery storage have their own technical and cost disadvantages when they operate in arid regions considered in this paper. In this study, $26 057 166 is the net present value of the project. Thus, the project is economically feasible with expected profit starting from the 20th year of operation.

5 | CONCLUSIONS

In this study, CSP technology is reviewed and a spreadsheet model for calculating the available solar irradiance in any location is developed. A thorough optimization process was developed, validated, and applied to optimize the solar field parameters of suggested CSP plant including tower optical height, heliostat structure width and height, number of horizontal and vertical panels, and receiver height and diameter. The optimization process resulted in a CSP power tower plant with 8 MW$^c$ capacity and a thermal energy storage for 10 hours with hybrid steam condensing system. The solar field of the plant was designed to be 0.45 km$^2$ in area with 2736 heliostats. The solar tower height was 140 m with receiver's height of 3 m and diameter of 5 m. The water required for the plant operation, heliostat washing activities, steam cycle makeup, and hybrid cooling system augmentation is estimated to be 95 579 m$^3$ per year. The levelized cost of energy however is still high compared to conventional power technologies.

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