Research

A simulation study of the effect of post-combustion amine-based carbon-capturing integrated with solar thermal collectors for combined cycle gas power plant

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Abstract

Post-combustion carbon capture with solvent designed to sequester carbon from power plant is a promising and well-known technology. However, a vital drawback is the reduction of the power plant output due to the energy required to separate captured CO₂ from the solvent, known as a re-boiler duty. In this paper, two configurations were simulated and economically examined to mitigate the re-boiler duty and power loss from the 495 MW West Damietta power plant, Egypt. The first approach is to increase carbon concentrations in the feed to carbon capture plant by recycling part of exhaust gas back to the combustion chamber with different ratios (0%–35%), the second approach is implementing parabolic-trough solar collectors to handle the reboiler load instead of low-pressure steam extracted from the power plant. Both power and CO₂ capturing plants were simulated using Aspen Hysys. Parabolic trough solar collector plant was simulated using system advisor model software. The results revealed that increasing carbon content led to a remarkable decrease in reboiler duty by up to around 20%. It was also found that integrating the solar plant with thermal storage system highly improved the optimum production compared to plant without thermal storage. Carbon increase also affected the levelized cost of energy which had 1.39% reduction and 6% decrease in carbon cost of avoidance using 35% recirculation ratio.

Keywords Carbon emissions · Post-combustion capture · Exhaust gas recirculation · Solar heating · Combined cycle gas turbine

1 Literature review

The crucial issue for each nation's sustainable economic growth is energy. However, the balance of economic growth and protection of environment is always an inevitable challenge for the sustainable development of the human population worldwide. Rapid economic growth has gradually increased demand for energy in recent years, through low cost, high calorific value fossil fuels, such as coal and natural gas which are commonly used in power plants [1]. The concern is that emissions of greenhouse gases contribute to global warming, rising sea levels and other environmental effects. In 2015, countries around the world signed the Paris Agreement calling for lower CO₂ emissions to slowdown the increase in average global temperature. Renewable energies are green sources that escalate with a noticeable rate [2]. However, in the near term, fossil-based fuels will be the primary selection for most energy applications. Combined cycle gas turbine (CCGT) power generation plants currently account for more than 20% of global electricity production and the efficiency

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of CCGT plants can reach up to 55–60% [3, 4]. To reach the desired CO₂ reduced emissions, CCGT power plants equipped with CO₂ capture and sequestration unit will be a vital solution to be used. Carbon capture and utilization technologies are categorized into three sections, pre-combustion capture, post-combustion capture (PCC) and oxy-fuel combustion capture [5, 6]. Among these technologies, post combustion capture eliminates the need for major to existing combustion processes and facilities; thus, it provides a way for near-term CO₂ capture for existing stationary fossil fuel-based power plants and can be used for new ones in future with further advancement of the technology [7]. Different types underlie post-combustion carbon capture such as MEA-solvent based chemical absorption process [8], adsorption process [9], membrane technology [10] and temperature swing adsorption [11]. Post-combustion CO₂ capture based on monoethanol-amine (MEA) is one of the most feasible approaches and recognized as the first choice for most demonstration projects due to its high technical maturity, large-scale applicability, good absorption effect and strong ability to remove CO₂ from low CO₂ concentration flue gas and very effective when integrating with CCGT power plant [12]. The current commercially available gas turbine technologies, CCGT with post combustion capture systems have been reported to have higher thermal efficiencies, and appear likely to give low total electricity costs and incurs lower capital costs, when compared with pre-combustion capture and oxy-fuel technology [13]. However, flue gases from natural gas-fired power plants raise challenges for post combustion capture technologies due to the relatively low CO₂ concentration which decreases partial pressure of CO₂ and then escalates the required reboiler duty which will finally impact net plant efficiency [14]. The main drawback that appears when integrating a post-combustion carbon capture unit with CCGT is the high reduction in power plant efficiency due to solvent regeneration requirement and auxiliaries load of the capture unit. Energy consumption due to integrating PCC can be decreased by adjusting the configuration of the system structure. For instance, the exhaust gas recirculation (EGR) process has demonstrated that CO₂ concentration is increased in flue gas, the power penalty is relatively decreased and overall performance of the power plant is enhanced. Various studies were conducted on the amount of energy deducted from different types of power plants integrated with distinct PCC technologies were found to range from 20 to 60% of the overall output power [15].

Integration of PCC using 30 wt% MEA absorption technology with power plants has shown a notable reduction in net efficiency with 9.7%. The highest contributor of the total thermal energy losses was for reboiler heat duty required to regenerate the solvent, compression of produced gaseous CO₂ and the parasitic powers of PCC circulating pumps [16]. Global contributions focused on two main bases to partially reduce the issues concerned with lost energy after integrating PCC to power plants. The first pillar is increasing CO₂ content in the feed of PCC unit by a replacing fraction of the excess air entering combustion box by either circulation part of the exhaust gas, steam injection or water vaporization to control the flame temperature and combustion gas produced after combustion chamber. Burning more fuel which used as a comburant to the excess air in exhaust gas. Exhaust gas recirculation (EGR) is recycling part of the exhaust gas back to the gas turbine inlet to be combusted with fuel and air. Process simulation models and experimental works have been initiated for the effect of absorption process using monoethanolamine (MEA) with strength (30 wt%) solution with water on the reboiler specific duty and size of contactor column with improving the CO₂ levels in the inlet gas, results from process models revealed that a notable reduction in specific reboiler duty happened when CO₂ levels rise to 6 vol%. Further, increase in the concentration of CO₂, the specific reboiler duty still decreases but relatively slower [17]. Jordán et al. [18] have showed that, using 40% of EGR ratio on 400 MWe CCGT integrated with MEA based capture plant, will increase the CO₂ levels in the inlet stream to PCC unit from 4.2 vol% to 7.05 vol% and also decrease the mass flow rate of the feed entering the unit. As a result of that, the required thermal energy witnessed a reduction from 3.6 to 3.52 GJ/tCO₂ and noticeable decrease 16% in levelized cost of energy (LCOE). Simulation work is done by Junjiang et al. [19] on 391 MW_e CCGT equipped with solvent based post-combustion carbon capture plant. Integrating PCC with CCGT has reduced power plant efficiency by 7.8%. They proposed three different configurations. First one involving EGR with power plant and carbon capture plant, the results showed that applying 35% EGR decreased energy penalty percentage from 13.95 to 12.46% and increased efficiency around 2%. The second one is recovering waste heat from the system using double-pressure organic Rankine cycle (ORC), the power generation efficiency increased efficiency approximately 1%. The third configuration was using cold gas stream to generate power which increased efficiency by around 2.51%. Agustín et al. [20] showed that EGR is a viable technique after increasing the efficiency of the CCGT power plant by 0.5% points which reduced the reboiler duty and capture plant size.

Renewable energy has a high potential in decreasing energy penalties than the other strategies that were discussed. Renewable energy includes wind, photovoltaic and solar thermal. The potential of using solar energy in industrial processes was reviewed and discussed in the work done by Sharma et al. [21] where solar energy is used in a wide range of industries such as food processing, textile, pulp, paper, chemical, pharmaceutical, cement, and leather products. The chemical industries which include distillation columns heated by a reboiler usually requires a

temperature range between (100–200 °C) and the heat transfer fluid used is usually hot water or steam. A life cycle approach was studied by on 300 MW_e coal-fired power plant integrated with PCC plant and assisted by Wang et al. [22] using parabolic trough solar collectors they proposed two configurations, the first one is solar assisted plant which directly heating regenerator reboiler and the second one solar assisted repowering stage applying thermal energy for high pressure feedwater preheater. Results showed that, a high increase in LCOE in the case of reboiler direct heating compared to the second system and the output power loss reduced about 16.62 MW while in the second configuration, no energy loss was detected. Wang et al. [23] constructed a solar assisted pilot module to test the performance of the system. Parabolic Trough Collector (PTC) and Linear Fresnel Reflector (LFR) were evaluated to provide heat duty for solvent regeneration. The results showed that, the two types can handle the required temperature. However, PTC expressed more efficiency than LFR. Lambert et al. [24] utilized solar energy by using solar power tower to support CCGT integrated with a pre-combustion carbon capture unit. They also applied EGR which took place after the compression stage of the gas turbine. EGR reduced the specific energy penalty from 15.3 to 13.6% and the renewable option was able to reduce energy loss associated with capture plant. Simulation model carried by Asiri et al. [25] on 555 MW_e CCGT plant integrated with post combustion carbon capture plant using amine located in Mexico. They adopted solar plant using parabolic trough solar collectors to assist post combustion carbon capture with reboiler heat load 258 MW_{th} with and without thermal energy storage. Their results showed that the most optimum design was applying (SkeyFuel Sky) collector with 6 h of thermal energy storage had the best energy production for reboiler heat duty is 250 MW_{th} due to thermal energy storage (TES) compared to system without TES which provided only 190 MW_{th}.

According to the above literature review, the power loss after integrating carbon capture unit can be reduced by using exhaust gas recirculation due to carbon dioxide increase that is reflected on the reboiler thermal load which is the main cause of power plant penalty. Designing solar thermal plant to support 100% of the reboiler duty thermal load which in return will minimize the parasitic loads. Moreover, through deep analysis of what was done in the above-mentioned literature review. In this article, the researchers aimed to fill the gap that existed in the previous works. As none of the preceding works had implemented a fully integrated system with carbon capture plant, increasing carbon concentration by using EGR, using solar thermal plant to take 100% of reboiler thermal load and study the impact of EGR on the solar plant, designing CO₂ onshore pipeline and calculating levelized cost of energy (LCOE) for the overall system based on EGR ratios.

2 System description

The proposed system is integrating CCGT power plant with post-combustion carbon capture plant equipped with EGR configuration and solar thermal plant using parabolic trough solar collectors to provide reboiler thermal load during the available sun hours instead of extracting low-pressure steam from the power plant. CO₂ is transported via onshore pipeline to be used as a feedstock for petrochemical product. CCGT is composed of two gas turbines, steam turbines and PCC have two main sections, CO₂ absorption unit by MEA and CO₂ compression section. A schematic process flow diagram for CCGT integrated with PCC and compression is shown in Fig. 1.

2.1 Combined cycle gas turbine power plant description

The main components of the plant are an air compressor (AC), gas turbine (GT) and heat recovery steam generator (HRSG) with two stage pressure steam turbines high pressure steam turbine (HPST) and low-pressure steam turbine (LPST). The air is compressed by an axial air compressor and then mixed with natural gas in the combustion chamber before to combustion. The flue gases resulted from the combustion will go through the turbine impellers and then drive the turbine. The flue gases are discharged through HRSG to extract the remaining heat for water preheating and steam generation. HRSG consists of two steam generation systems called low pressure evaporator and high-pressure evaporator, it drives a steam turbine to generate electricity in form of a steam Rankine cycle. EGR configuration is the recycling of a specified portion of the flue gas from the outlet of HRSG to the air compressor for mixing with fresh air. EGR enhances CO₂ concentration in the flue gas inlet to capture unit and reduces the penalty of the system with no big change in plant main structure as mentioned before in the literature. A schematic diagram of the CCGT power plant is shown in Fig. 2.

Fig. 1 Schematic diagram of CCGT power plant with PCC process and EGR

Fig. 2 Schematic diagram of CCGT power plant

2.2 Post-combustion carbon capture plant description

The PCC unit consists of CO₂ capture and compression unit as shown in Fig. 3. The flue gas from the HRSG outlet is introduced to the contactor or absorber column where absorption reaction takes place. The capture unit uses MEA solvent with (30% wt) solution with water [18]. The CO₂-free gas, called sweet gas, is discharged from the column overhead to the atmosphere. However, the liquid containing CO₂ is called a rich solution that leaves the tower from the lower end and is preheated using the hot stream that left the regenerator tower to optimize the heat utilization of the unit and then flows to the stripper column. CO₂ is separated from the regenerator overhead and solvent without CO₂ is called lean solvent is cooled and directed again to absorber tower. The traces of CO₂ and water mixture from stripper overhead are cooled and condensed and recycled back to the tower. The non-condensed phase which is mainly CO₂ is compressed and pumped through the onshore pipeline.

2.3 Solar industrial process heating

Industrial process heating (IPH) involves heating tool that provides heat transfer medium for specific user which requires this heat for a final product. This heat can be transferred directly or indirectly, the direct method includes

Fig. 3 Schematic diagram of PCC unit

heating the desired material instantly, while the indirect requires another stream which is called heat transfer medium is heated and then transfer the heat to the final destination. Implementing heat transfer medium in industrial process heating relays on the type of application which requires the heat. The heat transfer fluid must have some features which make it as a good option for most of the industries. These features such as: low vapor pressure, high heat capacity, low viscosity, low degradation rate and less corrosive. Most of the heat transfer mediums used in industries involves thermal oil, steam and pressurized water. Steam is the most dominant heat transfer fluid used in industrial process. From the above literature review, it can be seen that the solar thermal plant is used as a mitigation method to minimize the thermal load of the PCC plant. Solar energy utilized in the industrial process heating is one of the promising methods as an alternative option for energy supplier to a lot of oil importing countries. The steam is generated by heating water in a heat exchanger. Parabolic trough solar collectors are used to collect solar heat, heat is picked up by working fluid which is called heat transfer fluid (HTF) which extracts heat from the collectors, and then heats the water until it converted into steam. The steam is finally directed to the PCC reboiler to regenerate the solvent.

2.3.1 Solar thermal plant with thermal energy storage

The higher energy requirement makes it economically useful to increase dispatchability in the device by thermal storage combined with solar energy. The uses of thermal storage in the industry are demonstrated in Fig. 4. Thermal energy storage (TES) is the most common source of energy supply for potential use by concentrating solar thermal power plants. The primary driver of construction of a storage facility in solar power plants is also the transient quantity of solar radiation. The solar thermal storage system typically comprises three main elements, storage medium, heat transfer mechanism and containment system. The energy stored can take the form of sensible or latent heat or even chemicals. The aim of the part of the process of heat transfer is to supply and collect energy from the media. TES is used for containment to reduce system losses. Sensible heat storage involves materials such as molten salts and synthetic oils. In this configuration the thermal energy is retained by increasing the temperature of the fluid. The difference of heat and temperature during charging and discharging is used in this system. The quantity of heat depends on the specific heat of the medium and the storage content. Latent heat systems are built based on the principle of phase change in a material at a constant temperature. The storage process is nearly isothermal

Fig. 4 Schematic diagram of SIPH supporting plant

which provides a higher amount of energy compared to sensible heat storage system. This is very beneficial when combined with solar thermal plants to reduce system intermittences.

2.3.2 System design description

The full heat demand for the amine regeneration is provided by the solar field which will support 100% of the thermal load of carbon capture plant. Figure 4 illustrates the configuration of the solar thermal plant with TES that fulfils reboiler duty. The system actually composed of three main parts; the solar field to collect heat from the sun, a reboiler to extract the required heat load for carbon capture unit and a thermal storage system to save energy for later use. The two tanks (hot and cold) configuration to store energy was assumed in this study to improve the intermittency in the system. The hot tank holds a high temperature thermal fluid, while the cold tank holds the cold recycled fluid after the energy was extracted by the reboiler. The solar field charging process is based on direct or indirect methods. The difference between them is the medium used. Indirect method involves two tank system using a thermal storage media in addition to HTF. This will require additional heat exchanger to transfer heat between the two fluids. In this study direct energy storage was used. The CSP models concerned with IPH have some differences from the original models which involve electricity production. In concentrated solar plant with electricity production, the solar plant is coupled to the normal steam Rankine cycle thermal power block where both produces steam and generate electricity, but in case of the IPH model the power block section is ignored where the solar field energy is used to provide direct steam or heating for different

thermal processes. In cloudy days the plant is backed up with TES system. In case of TES is not working or unable to be charged during winter, reboiler duty is supplied by the low-pressure steam cross-over point and it will affect the power plant output power accordingly.

3 Research methodology

3.1 Model establishment

To analyze the system with fewer complications, the following assumptions are considered in the simulation, in order to help the solver converging smoothly specially heat exchanger module.

- 1) CCGT is simulated in the steady state model.
- 2) No leakages are occurred in the different configurations of the system.
- 3) The energy loss and friction loss in all equipment are neglected.
- 4) The heat exchange between the environment and equipment is also neglected.

3.1.1 Energy balance of the combined cycle gas turbine power plant

For a CCGT power plant, the power output derives from a gas turbine and a steam turbine. The gas turbine and axial air compressor are connected on a single shaft by a mechanical device. The net power output of the gas turbine is shown as follows [26]:

$$W_{GT} = \left[\frac{W_{gt} - W_{ac}}{\eta_{mech}} \right] \times [\eta_{gen}] \quad (1)$$

where W_{gt} gas turbine power output 681.8 MW, W_{ac} air compressor power consumption 280 MW, η_{mech} mechanical efficiency 99.8% and η_{gen} is the generator efficiency 99.8%.

The net power output of the steam turbine can be expressed as follows [26]:

$$W_{ST} = [W_{HPST} + W_{LPST}]x_{gen} - [W_{HPP} + W_{LPP}] \quad (2)$$

where W_{HPST} , W_{LPST} mechanical work of high-pressure and low-pressure steam turbines 62.43 MW and 81.6 MW respectively, and W_{HPP} , W_{LPP} are the consumed power by high-pressure and low-pressure recirculation pumps 1.603 MW and 0.04 MW.

The total power output of the CCGT power plant can be expressed as follows [26]:

$$W_{netCCGT} = W_{GT} + W_{ST} \quad (3)$$

Table 1 Air and fuel composition inlet to gas turbine

Parameters	Air	Fuel
Mass flow rate (kg/s)	650	18.8
Pressure (bar)	1	15
LHV (KJ/kg)	–	48,453
N ₂	79.5%	–
O ₂	20.5%	–
CO ₂	–	0.01%
CH ₄	–	95.4%
C ₂ H ₆	–	4.24%
C ₃ H ₈	–	0.3%
C ₄ H ₁₀	–	0.04%
C ₅ H ₁₂	–	0.01%

Table 2 Model parameters of CCGT process

Description	Unit	Values
Turbine inlet temperature	°C	1050
Compression ratio	–	10.44
Turbine exhaust temperature	°C	515
HP turbine inlet pressure	bar	106
LP turbine inlet pressure	bar	5
Superheated steam temperature	°C	500
Ambient temperature	°C	25
Generator Efficiency	%	90

Table 3 Comparison between CCGT actual data and simulation

Parameter	Unit	Actual Data	Simulation
GT power	MW	290	351
ST power	MW	190	144
Plant net power	MW	480	495
Plant efficiency	%	56.02	56.6

Table 4 Comparison of PCC simulation with referenced work

Parameter	Benchmark work [26]	Simulation
Absorber column trays	14	13
Stripper column trays	10	8
Reboiler Duty (MW _{th})	161	165
Reflux ratio	0.1	0.3

Table 5 PCC unit design parameters

Preliminary design	Unit	Values
Lean solvent flow rate	kmole/h	160,000
Inlet gas flow rate	kmole/h	109,141
No of absorber columns	–	1
No. stripper columns	–	1
Absorber capture efficiency	%	85
Flue gas inlet temperature	°C	40
Absorber pressure	bar	1
Stripper pressure	bar	2

3.1.2 Efficiency of the power plant

The calorific value Q_{NG} of the combusted fluid entering the combustion chamber of the power plant is calculated as follows [19]:

$$Q_{NG} = \dot{m}_{NG} \cdot XLHV \quad (4)$$

where LHV is the low heating value of natural gas 48,453 kJ/kg, $\dot{m}_{NG}$ is mass flow rate of the fuel 18.08 kg/s.

Auxiliary equipment power consumption W_{aux} consists of power consumption of cooling water and amine pumps is as follows [26]:

$$W_{aux} = W_{Amine_Pumps} + W_{CO_2_Comp} + W_{CO_2_Pump} \quad (5)$$

where W_{Amine_Pumps} , $W_{CO_2_Comp}$, $W_{CO_2_pump}$ are total power consumed by amine pumps, CO_2 compressors and CO_2 pump 0.15 MW, 15.8 MW and 0.5 MW respectively.

The total power output of CCGT power plant is as follows [26]:

$$W_{total} = W_{Net_CCGT} - W_{aux} \quad (6)$$

The efficiency of CCGT power plant is as follows [26]:

$$\eta_{CCGT} = \frac{W_{Total}}{Q_{NG}} \quad (7)$$

3.1.3 Verification of power plant model

The simulation of the CCGT power plant with PCC unit is simulated by Aspen Hysys V8.6 workflow. Gas turbine SIEMENS (V94.2) modelling used Peng-Robinson (PR) fluid package, while steam turbines were represented by ASME steam tables model. Gas turbine and steam turbines are simulated and compared with the actual output power and overall efficiency that represent Damietta power plant. The design data including feed air, fuel gas composition and other parameters are listed in Tables 1 and 2. The comparison between actual data and simulation results are listed in Table 3. There is a small deviation between actual and simulation data. Therefore, the accuracy of the model is verified.

3.1.4 Verification of carbon capture process

The acid gas absorption using aqueous amines is performed by using the Amine package which uses Ken-Eisenberg or Li-Mather as thermodynamic models for the amine solutions. A model was selected as a benchmark that was reported as a master thesis work. This published work data and results were utilized in this project to validate Aspen Hysys model results and system performance [27]. Table 4 shows the comparison between the current work and the cited ones, along with the operating parameters of the system that are given in Table 5.

3.2 Compression train and pipeline transportation

CO_2 compression train is modelled by Aspen Hysys, its load is accounted for the total parasitic loads. The operating pressure for the CO_2 pipeline must be maintained at supercritical conditions or liquid dense phase with pressure above 73.8 bar [28]. A final compression stage discharge pressure of 73.8 bar and a pump is provided to raise the pressure to 110 bar, the compression and pumping are specified according to the work conducted by Herraiz [14]. The compression train consists of three centrifugal compressors, intercoolers and scrubbers. The pumping section was modelled in the same flowsheet with the compression train. CO_2 transportation is the transition between capture and storage or usage, it's considered the lowest cost stage among the whole system. On land, CO_2 can be transported by tankers, trucks, railcars and pipelines. The efficient way to transport CO_2 is via the appropriate design of pipeline [28]. In this study, CO_2 pipeline design calculations were done an excel spreadsheet. Pipeline material was also selected to best suit the specifications of the product.

3.2.1 Mathematical model of CO_2 pipeline

An excel spreadsheet is used for pipeline design using the following equations.

The optimum inner diameter of the pipeline is estimated as follows [28]:

Fig. 5 The effect of EGR ratio on O₂, CO₂ concentrations and Reboiler duty

Table 6 Process parameters comparison

Case	Unit	CCGT	CCGT + PCC	CCGT + PCC + EGR
Gas turbine power	MW	350	350	349
HP steam turbine power	MW	62.43	62.41	64.90
LP steam turbine power	MW	81.6	35.86	46.98
Acid gas booster power	MW	N/A	3	1.79
Power plant net output	MW	495	430.65	444.11
Total power penalty	MW	N/A	65.27	51.80
Plant net efficiency	%	56.61	49.15	50.62
Exhaust mass flow rate	kg/s	976.1	976.1	628
Exhaust gas CO ₂ content	mole%	3.2	3.2	5
Exhaust gas outlet temperature	°C	515.21	515.21	521.53
Steam temperature	°C	505	505	518
Total absorber circulation rate	kg/s	N/A	998.5	769.5
Heat required in reboiler	MWth	N/A	165	131.5
Net specific emissions	kg CO ₂ /MWh	351.53	58.62	56.18

$$D_{opt} = 0.363 \times Q_v^{0.45} \times \rho^{0.13} \times \mu^{0.025} \quad (8)$$

where Q_v is CO₂ flow rate 0.463 m³/s, ρ is density 98.88 kg/m³, μ is viscosity 0.02285 cp, these values were obtained from Aspen simulation flowsheet.

The friction factor is estimated using the follow equation:

$$f = \frac{1.325}{\left[\ln \left(\left(\frac{\epsilon}{3.7D} \right) + \left(\frac{5.74}{Re^{0.9}} \right) \right) \right]^2} \quad (9)$$

where D is inner diameter 375 mm, ϵ is pipe roughness 0.259 mm for carbon steel.

The pressure drop per unit length is represented as follows [28]:

$$\Delta P/L = \frac{8fQ^2}{\rho\pi^2D^5} \quad (10)$$

where f is friction factor 0.0128, L is pipeline length 15 km.

The thickness of pipeline is estimated as follows [29]:

$$t = \frac{P_{max}D}{2(SFE - P_{max})} \quad (11)$$

where, P_{max} is the maximum operating pressure 10 MPa, F is the design factor 0.72, S is the specific yield stress of pipe material 4137 MPa, E is a longitudinal joint factor 1.

The pipeline weight is calculated using the following [30]:

$$W_s = \pi L \rho_{steel} t (D_i + t) \quad (12)$$

where, t is wall thickness 9.46 mm, ρ_{steel} 7850 kg/m³.

4 Process integration

4.1 Combined cycle gas turbine power plant with carbon capture and exhaust gas recirculation

The integration of the carbon sequestration plant will decrease the output power and efficiency of the CCGT power plant. The typical capture rate of post combustion carbon plant ranging from 85 to 90% of the CO₂. In order to simulate on the least reboiler steam consumption rate, the removal rate 85% is selected for this project [27, 28]. Integrating post combustion carbon capture unit, part of LP steam existing HPST to LPST is used for solvent regeneration in the reboiler resulting in decreasing the output power from LPST by 44%. This reduced the power plant efficiency with nearly 13%. To restore part of that lost power, EGR is implemented to increase carbon levels in the feed to carbon capture unit, this will support the partial pressure of the carbon in the stripper section and then decrease the required power to separate the carbon from the solvent. EGR is simulated at different ratios depending on the oxygen

Fig. 6 Hourly DNI for parabolic trough collector at Damietta City

levels returning back to the combustor. In order to determine the EGR ratio, the change of O_2 concentration, CO_2 concentration and capture energy consumption of the reboiler unit CO_2 with EGR ratio are investigated as shown in Fig. 5. With increasing EGR ratio, the reboiler energy is gradually decreasing, O_2 concentration decreases while CO_2 increases. Previous studies have showed that, oxygen levels in the combustion chamber below 16%, the flame shape and flue gas temperature will be affected negatively and can lead to oxygen starvation [14, 31, 32]. At 35% EGR ratio, oxygen content was around 17%, below that concentration, unburned hydrocarbon started to appear in the exhaust gas. Therefore, the EGR ratio of 35% is selected in this paper. The system integrations results are shown in Table 6.

4.2 Solar thermal plant integration

4.2.1 Site description and solar energy available

The CCGT power plant is located in Kafr Al Battikh, a region in Damietta Governate, one of the coastal cities in Egypt. The plant is simulated for a period of one-year (0 h to 8760 h). For the simulation of the hypothetical CSP power plant, the site with direct normal irradiance (DNI) and the typical metrological year (TMY) data in the NREL database has been used to evaluate the performance of the parabolic trough solar thermal plant. The climate data includes hourly DNI, ambient temperature, wind speed, atmospheric pressure, sun angle and solar azimuth angle.

This region relies on medium solar radiation which enjoys Direct Normal Solar Irradiation (DNI) which equals according to solar atlas data approximately by 5.455 KWh/m² per day. The Global Horizontal Irradiation (GHI) for Damietta is 5.425 KWh/m² per day, the Diffuse Horizontal Irradiation (DHI) is 2.024 KWh/m² per day and the recorded Direct Normal Irradiation (DNI) is 5.425 KWh/m² per day (~ 1980 KWh/m² per year) [33].

Figure 6 shows the variation of normal irradiance per each month at Damietta. The maximum DNI of 7.7 KWh/m² per day was recorded during June and July while the minimum 3.6 KWh/m² per day of DNI during December. The average wind speed in Damietta is 4.33 m/s lower than the critical wind speed of 15.64 m/s that may lead to solar system structure collapse. The average amount of sun hours for this location is 14 h per day in June which is the longest time for sunshine in the year compared to 10 h in December which is the shortest time [34].

4.2.2 Parabolic trough concentrated solar plant with thermal energy storage in solar industrial process heating

Parabolic trough collector (PTC) is the best technology to reach high temperature ranges up to 550 °C with optimum commercial concerns when compared to other solar technologies such as Fresnel collectors, solar towers and dish sterling [35]. PTC has a minimum energy loss by convection and conduction due to the annulus between the absorber tube and surrounding glass, and the absorber is coated with a material that has a solar radiation absorptivity higher than 0.95 and low emitted heat which lead to a good reduction of the radiation losses. The best used collector for SIPH applications is the (SkyFuel SkyTrough) solar collector assembly (SCA). This module had been used in Stillwater hybrid solar-geothermal plant in the USA [36]. A large number of studies that were simulated by system advisor model (SAM) have selected (Schott 2008 PTR80) as the optimum heat collector element (HCE) as it has the optimum efficiency which is enhanced by increasing the length of the receiver by four meters and above. Most of the studies that used SAM to simulate parabolic trough solar plants recommended only two types among all the fluids. Therminol VP-1 and HITEC Solar Salt are the suitable candidates because they have a good heat capacity, higher specific heat and higher density and lower viscosity which gives them the ability to flow through the pipe with good heat transfer properties [37]. In this work, direct thermal energy storage which involves using the same HTF will be evaluated [25].

4.2.3 Mathematical model of solar field with thermal energy storage

For the heat gained by the collector is as follows [25]:

$$Q_{Col} = DNIXA_cX\eta_c \quad (13)$$

where, η_c collector efficiency 0.68% [29], DNI 875 W/m².

The collector outlet temperature of heat transfer fluid (HTF) is as follows [25]:

$$T_{oc} = T_i + \frac{Q_{Col}}{\dot{m}x C_p} \quad (14)$$

where, $\dot{m}$ single loop mass flow rate 12 kg/s, T_i inlet temperature 130 °C, C_p HTF heat capacity 2.45(Kj/kg °C).

The number of collectors is estimated as follows [25]:

$$N_c = \frac{Q_r}{Q_{col}} \quad (15)$$

where, Q_r required thermal load for carbon capture plant (185 MW_{th} to 151 MW_{th}).

The Number of collectors per loop is calculated as follows:

$$N_{C/L} = \frac{T_o - T_i}{T_{oc} - T_i} \quad (16)$$

where, T_o loop outlet temperature.

The total number of loops is expressed as follows [25]:

$$N_L = \frac{N_c}{N_{C/L}} \quad (17)$$

In case of implementing solar thermal storage system, extra calculations are involved in the model to calculate the additional heat to be used in later time.

The total HTF mass flow rate after adding thermal energy storage is as follows [25]:

$$\dot{m}_T = N_L x \dot{m} \quad (18)$$

The mass of HTF stored in the tanks is represented by the following [25]:

$$m_s = \dot{m}_T x t_s \quad (19)$$

where, t_s is the storage time which is assumed to be 6 h [25]

The mass flow rate during the sun hours is estimated by the following:

$$\dot{m}_d = \frac{m_s}{t_d} \quad (20)$$

where, t_d is the total sun hours 10 h for Damietta city.

The total number of collectors after adding thermal storage system is calculated as follows:

$$N_s = \frac{\dot{m}_d x C_p x (T_o - T_i)}{t_d} \quad (21)$$

The number of loops added after thermal energy storage is calculated as follows [25]:

Table 7 Solar thermal plant parameters without thermal storage

EGR ratio (%)	Target load (MW _{th})	No. of loops	Total no. of collectors	Annual Gross Energy (MWh _{th})	LCOE (\$/MWh _{th})
0	185	94	470	401,855	21.54
5	182	92	460	393,579	21.49
10	178	90	450	385,024	21.41
15	172	85	425	366,324	21.38
20	165	81	405	349,389	21.31
25	157	77	385	332,185	21.29
30	152	62	372	321,490	21.21
35	151	62	372	321,289	21.20

Fig. 7 Hourly thermal power per month for solar plant without TES

Table 8 Solar thermal plant parameters with thermal storage

EGR ratio (%)	Target load (MW _{th})	Target receiver thermal power (MW _{th})	No. of loops	Annual net energy (MW _{th})	LCOE \$/MW _{th}
0	185	277.5	140	597,873	21.20
5	182	273	138	589,521	21.15
10	178	267	135	576,586	21.00
15	172	258	127	545,865	20.81
20	165	247	121	520,227	20.53
25	157	235	116	498,573	20.14
30	152	228	93	479,959	20.05
35	151	226.5	93	479,958	20.03

$$N_{Ls} = \frac{N_s}{N_{C/L}} \quad (22)$$

The total number of loops of solar field and thermal storage is represented as follows [25]:

Fig. 8 Hourly thermal power per month for solar plant with TES

$$N_{TL} = N_{Ls} + N_L \quad (23)$$

5 Results and discussion

5.1 Solar thermal plant without thermal energy storage

The constant heat loss is 4% (default value in SAM), HTF temperature rise is 100 °C in the solar system, the temperature of HTF leaving solar collectors and the regeneration reboiler are 230 °C and 130 °C respectively. Therminol VP-1 synthetic oil is a suitable candidate to be used as HTF because it has a good heat capacity, higher specific heat and higher density and lower viscosity which gives them the ability to flow through the pipe with good heat transfer properties with mass flow rate per loop 6 kg/s and the DNI is 875 W/m². The solar collector and thermal receiver that were selected are Skey-Fuel Sky and Schott PTR 80 respectively. These conditions are constant for the two design cases. Table 7 shows the solar thermal configurations according to different PCC heat loads required. The SM calculated was 1.02 which gives the same required thermal load. Based on the simulator results for the 185 MW plant with annual thermal energy of 401,855 MW for reboiler duty and auxiliary power, the plant is capable of producing thermal power from 6 A.M to 7 P.M on average (12 h per day) depending on the time of the year. The highest energy produced is during the months of June, July and August. On the other hand, the lowest energy produced is in December approximately 80 MW_{th}. The hourly energy production in each month is represented in Fig. 7; it also shows the variation of incident thermal energy affects the energy production. The maximum heat generated for reboiler is recorded as 180 MW_{th} and maximum incident power recorded during July with 270 MW_{th}.

5.2 Solar thermal plant with thermal energy storage

In this configuration, the same collectors and receiver types are used as in the previous design. The available land area for installing the thermal was measured using the Google Maps tool, which is nearly 1.3 km². The suitable SM estimated by SAM according to the available land area next to the power plant is 1.5. TES was introduced to decrease the intermittency in the system when the sunlight is not available. The target energy receiver thermal power is higher than the actual required thermal heat to able to store this surplus energy for the later use. The density of Therminol VP-1 oil is 934.245 kg/m³. The system specifications after simulating thermal energy storage are represented in Table 8.

From the results, the power generation increased considerably from March to September as illustrated in Fig. 8. The highest solar thermal produced from the system is 280 MW_{th} while the heat sink power recorded at 180 MW_{th}. The amount of thermal energy storage charging and discharging thermal power during the day fluctuates according to the availability of solar radiation. From the previous results, solar thermal plant with TES showed more efficient performance than the normal system as it managed to provide more solar production with slightly lower cost. Applying EGR had decreased the LCOE of system by (\$0.34/MWh_{th}) in case of solar thermal system with no TES, while it was decreased by (\$1.17/MWh_{th}) in case of TES system.

6 Plant cost model

One of the key objectives of this work is to determine the effect of implementing both PCC, PTC plants with compression and transportation on the levelised cost of electricity (LCOE) from the 495 MW CCGT. In most academic studies the cost calculation is done by two methods, net present value (NPV) or LCOE over the economic lifetime. The calculation of LCOE includes data of rated capacity MW, capital cost \$, operating and maintenance costs \$, efficiency %, fuel LHV and capacity factor %. Equipment costs are estimated most of the time from other studies and reveal a wide variety of uncertainties. Equations below are used to calculate LCOE on 25 years of the total plant life. The cost model was calculated using an excel spreadsheet at each EGR ratio. Based on the calculations, the capital cost of the whole integrated system kept decreasing after implementing EGR, the lowest cost was at 35% ratio. Thus, the results at 35% only are presented in this paper.

Three cases are considered; one where the CCGT alone, CCGT + PCC + Compression and CCGT + PCC + Compression + Solar thermal plant.

The LCOE for the all whole system is calculated as follows [31]:

$$LCOE \left(\frac{\$}{MWh} \right) = \frac{CAP \times CRF}{CF \times Netpower} + (O\&MCosts) \quad (13)$$

Fig. 9 Cost of avoidance for CCGT + PCC and CCGT + PCC + Solar system

Table 9 Solar thermal plant different studies simulated by SAM

	Unit	Asiri et al. [25]	Bravo et al. [44]	Current study (35% EGR)
Thermal Load	MW	258	219.47	151
Solar Multiple	–	1.54	1.3	1.5
Solar collector duty	MW _{th}	397.32	372.1	226.5
LCOE of solar system (thermal)	\$/MWh _{th}	31.4	40.57 ^a	20.03

where, *CAP* is total system capital cost, *CRF* is capital recovery factor, *CF* capacity factor 80% [32]. Capital cost of CCGT (based on the official data from the plant), PCC, compression station and onshore pipeline are 80 M\$, 136 M\$ [38], 2 M\$, 1 M\$ respectively.

O&M in \$/MWh costs based on Egyptian natural gas price 3.01 \$/GJ [39] for CCGT which includes only natural gas 19.08 \$/MWh and water costs 0.009 \$/MWh [40]. In PCC plant, natural gas increased 26.37 \$/MWh to provide the additional loads required by the capture plant, water demand increased as well 0.01246 \$/MWh and MEA solvent makeup is added to the cost 8.68 \$/MWh [41]. The operating costs for compression and onshore pipeline are assumed to be 4% of the capital cost [30].

The capital recovery factor is estimated as follows:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (14)$$

where, *i* is interest rate 11.3% [42], *n* is plant life in years.

The cost of solar collectors is calculated as follows [23]:

$$C_{solar} = \frac{N_C \times C \times F_{solarfield}}{1 \times 10^6} \quad (15)$$

where, *C* is unit cost per collector 3000 \$, *F_{solar field}* is cost factor for solar field 1.5 [25]. The capital cost of the overall solar field 75 \$M this cost breakdown is solar collectors with TES tanks plus engineering cost and Egyptian customs which are 20% and 7.5% [43] of the total capital cost respectively. O&M cost is assumed to be 1.5% of the capital cost.

The cost of CO₂ avoidance is estimated as follows [32]:

$$COA = \frac{[LCOE]_{withCCS} - [LCOE]_{withoutCCS}}{[CO_2]_{emittedwithoutCCS} - [CO_2]_{emittedwithCCS}} \quad (16)$$

Using the previous equations, the LCOE for CCGT as reference plant was estimated to be (34.31 \$/MWh). Integrating carbon capture plant, CO₂ compression and transportation with CCGT made LCOE increased dramatically. However, involving EGR at the mentioned ratios had a small reduction in LCOE from (47.98 \$/MWh to 46.71 \$/MWh). Implementing solar thermal plant with energy storage that operates for 12 h to support carbon capture plant parasitic loads will

Table 10 CCGT power plant surveyed with key metrics shown

	Unit	Luo and Wang [45]	Vaccarelli et al. [46]	Adams and Mac Dowell [32]	Current study
CCGT load	MW	453	383	420	495
Capture rate	%	90	90	90	85
NG price	\$/GJ	8.05	6	5.27	3.01
MEA price	\$/tonne	1777	2630	2164	2880
LCOE of CCGT plant	\$/MWh	71.1	55	51	34.30
LCOE of CCGT with PCC	\$/MWh	119.6	75	69	46.71
LCOE after integrating solar thermal pant	\$/MWh	NA	NA	NA	56.81

provide the thermal heat instead of the extra fuel injected to produce this thermal load. This saved fuel flow is considered to be revenue for the plant, as this solar boiler has no CO₂ emissions and, in return, would save carbon taxes (\$/tCO₂). However, solar thermal plant increased LCOE by 20.71% (from \$46.71/MWh to \$57.61/MWh). EGR slightly reduced LCOE from (\$57.61/MWh to \$56.81/MWh). The cost of avoidance (COA) is calculated for the reference plant integrated with carbon capture unit it showed (\$46.07/tCO₂) but it decreased after the applying EGR to be (\$40.80/tCO₂). The cost also escalated after integration of solar plant to reach (\$74.56/tCO₂). EGR had a remarkable decreased in COA from (\$74.56/tCO₂ to \$70.04/MWh) as shown in Fig. 9.

6.1 Comparison between LCOE of different studies simulated parabolic trough solar thermal plant by SAM Software

There are some academic papers which used SAM to simulate parabolic trough solar plant that used to compensate reboiler heat duty after integrating carbon capture plant. This comparison is used to show the variation of LCOE of only PTC solar thermal plant as shown in Table 9.

6.2 Differences between various studies of combined cycle gas turbine power plant integrated with carbon capture unit

A survey was undertaken to demonstrate the difference in LCOE between the previous studies and the current work. These studies are related to combined cycle gas turbine with nearly similar load. It is not easy to judge how practical the financial results are due to the differences of natural gas prices, capturing rate, local electricity prices and post combustion carbon capture prices. However, technical and economic data were extracted from different studies and listed in Table 10. This survey was undertaken just to expand the total reach of the same goal for carbon capture from exhaust from the combined cycle power plant.

7 Conclusion

In the current study, a simulation model of CCGT was built using Aspen Hysys software. The natural gas combined power plant with two gas turbines and two pressure levels steam turbines (HP & LP) has a total power capacity of 495 MW. CO₂ increased (from 3.2% mole to 5.1% mole) at 35% ratio EGR. The carbon capture plant was simulated by the same software, PCC power input which is considered as a parasitic load were reduced by increasing EGR ratio by 20% (from 65.27 MW to 51.80 MW). The solar thermal plant is simulated to fully provide 100% of capture plant thermal load and auxiliaries during daytime. SAM software was utilized at different EGR ratios. For 185 MW_{th}, solar plant maximum and minimum thermal power were 180 MW_{th} and 90 MW_{th} respectively. Adding TES system improved the thermal power needed for the reboiler in the months that had low productivity in the other model while the months which had the maximum production kept constant for a longer period of time along the day. LCOE was decreased when applying the thermal storage system and further reduction in cost was seen after applying EGR. The cost is calculated at the different EGR ratios, it showed a reduction (\$47.92/MWh to \$46.71/MWh) of LCOE when integrating PCC with the power plant at the 35% ratio. Implementing the solar thermal plant has added an extra expense (\$47.92/MWh to \$57.61/MWh). Applying EGR had reduced the cost (\$57.61/MWh to 56.81/MWh) at 35% ratio. The cost of CO₂ avoidance was also estimated and also decreased remarkably at 35% ratio (\$74.56/tCO₂ to \$70.04/tCO₂). Based on current findings, relative to normal combustion conditions, 35% of EGR was found to be the optimal and less expensive choice.

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Code availability Not applicable.

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