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COMBINED CYCLES INTEGRATED WITH A HEAT PUMP AND THERMAL ENERGY STORAGE SYSTEM FOR AIR PRE-COOLING – A TECHNO-ECONOMIC ANALYSIS

Rafael Guédez [a], José García [a], Antti Nuutinen [a], Giovanni Graziano [a], Guillaume Martin [a], Justin Chiu [a], and Björn Laumert [a]
a Department of Energy Technology, KTH Royal Institute of Technology, 100 44 Stockholm, Sweden

ABSTRACT

The present study analyses the influence that market has on determining the optimum combined cycle plant layout integrated with heat pump and cold storage that maximizes profits (in terms of sizing and operation strategies) for a given location nearby Turin, Italy, for which hourly electricity and heat prices, as well as meteorological data, have been gathered. A techno-economic modeling of the proposed layout has been implemented and a subsequent sensitivity study was performed to show the trade-off between minimizing investment and maximizing profits when varying critical size-related parameters (e.g. heat-pump power capacities and storage size), together with power-cycle design and operating strategies. Results are shown by means of a comparative analysis against the state-of-the art combined cycle. It is shown that the proposed heat-pump and cold storage integration layout for inlet temperature cooling would indeed be able to increase the power produced during periods of high electricity prices, but still it is shown that for the case-study considered (Turin), the added revenues during high-peaks do not compensate for the required investment, at least under the control strategies and economic assumptions undertaken in the study. Nevertheless, it is suggested that under different market conditions, and more specifically electricity price schemes with larger peak to off-peak variation, the proposed configuration could significantly enhance the profitability of power-oriented combined cycles.

INTRODUCTION

The liberalization of electricity markets and a growing penetration of renewables has led many countries to feel changes in the operation of their grids. The boundary conditions for the operation of conventional power plants are changing and, as such, an improved understanding of the varying loads and prices on the electricity grid is required to assess the performance of emerging combined cycle gas turbine (CCGT) concepts and to further optimize their design for these new markets in the pursuit of increasing their profitability, especially when considering co-generation of heat and power. A clear consequence of such renewable integration is the need for these plants for being more flexible in terms of tamping-up periods and higher part-load efficiencies. Flexibility becomes an even clearer need for combined heat and power (CHP) plants to be more competitive, especially when simultaneously understanding the complexity of market hourly price dynamics and varying demands for both the heat and the electricity markets. One way to achieve such flexibility in power oriented combined cycles (POCC) is by incorporating cold thermal energy storage (TES) together with large size industrial heat pumps (HP) into either new or already built plants. These new components would be used for an inlet conditioning system by controlling the air gas turbine inlet temperature. Lower air temperature means higher air density, therefore, higher air mass flow, which yields to higher power output, and vice-versa. For the last ten years, the main application of the inlet conditioning system has been for cooling purposes, providing a cost-effective way to add machine capacity (+10-15% for heavy-duty frames, up to 25% for aero-derivative frames) during the period when peaking power is required in operational environment with warm and dry weather (Kelhofer, 2009) (Venkateswararao, 2013), investigated the thermal energy storage inlet air cooling impact on the performance of a 445MW gas turbine. They analyzed various TES systems, among them, chilled water storage and ice storage, and concluded that the integration of cold TES is a cost-effective way to improve GT performance by boosting the power output during peak demand periods. The model used was zero-dimensional, meaning that no spatial resolution or fluid mechanics was considered. Moreover, boundary conditions such as ambient temperature and electricity price were assumed to be constant values and not time dependent, leaving room for future work on the matter. Mollenhauer (2017), studied the integration of HP and TES in CHP plants trying to achieve better performance in terms of greater flexibility, reacting to hourly-based electricity prices and dispatch conditions determined by end-user behavior and an increasing power input from renewable sources into the grid. However, the solution proposed was intended to gain flexibility by incorporating a warm TES to be used to buffer the heat supply from the CHP into a district heating network. In neither case has the TES-HP solution been applied to both cooling and heating the GT intake under varying boundary conditions. By actively controlling the GT intake as mentioned, not only power can be increased during electricity peak demand, but also lower mean environmental load and greater overall efficiency can be achieved during low electricity price periods. The integration of TES and HP units into CCGT plants represents a significant increase in capital expenditures (CAPEX). Thus, the objective of the present work is to analyze the profitability of POCC with integrated cold TES at the GT inlet together with large size industrial heat pumps under specific boundary conditions (weather and price) and for different component sizes.

POCC-TES LAYOUT

A simplified version of the layout proposed is shown in Fig. 1, where three main blocks can be identified. On the top center, a typical Brayton Cycle composed by a compressor, a combustor fed with natural gas (NG) and a turbine. On the right-hand side, a typical Rankine Cycle, forming the CCGT. Finally, on the left-hand side, the inlet conditioning unit, composed of four main components, namely: a GT air-to-liquid heat exchanger (GTHx) needed for changing the inlet air temperature; an ambient air-to-liquid heat exchanger (AmbHx) used for regulating the heat dissipated in the GT Hx by releasing extra heat to the ambient if needed; a heat pump (HP) used for either charging the cold TES whilst dissipating heat through the GTHx and/or the AmbHx, or for cooling directly the GT intake and, lastly; a cold TES unit based on phase change materials (PCM) at a nominal temperature of 5°C that, together with its respective pumping and piping systems, form the inlet conditioning unit. The heat transfer fluid (HTF) used in every loop of this unit is a water-glycol mixture, with a glycol share of 35% which compared against plain water, offers lower melting temperature and higher boiling temperature.

Four operational modes (OMs) have been defined and they would take place as a response to the boundary conditions (ambient temperature and electricity price) and strategies of operation desired. OM1 refers to normal operation. In this case the CCGT is run as if no integrated inlet conditioning (IIC) was in place and the GT inlet temperature would be the same as ambient temperature. In OM2 (continuous lines), the GT inlet is cooled down by means of the GTHx, which is fed with cold HTF discharged from the cold TES. This OM takes place whenever the electricity price reaches its daily peak and the ambient temperature is higher than 5°C. By discharging the TES lower temperature in the GT intake is achieved, which yields higher power output from the CCGT. OM3 is the charging mode (dashed lines). In this case the HP is used for charging the cold TES with a cold loop running through its evaporator. The heat from the condenser is dissipated either in the GTHx, in the AmbHx, or both, depending on the ambient conditions. OM3 (TES charging) is implemented when the electricity price is at its lowest value. In that way, the electricity consumed by the HP would have less impact on the CCGT performance. On top of that, by also heating the GT intake, the minimum power output of the power plant would be even lower which, depending on the conditions, could represent a benefit in terms of higher flexibility. Finally, OM4 refers to continuous cooling (dashed-dotted lines). In OM4 the TES is not used, and the HP is used for cooling the GT intake directly via the GTHx, whilst the heat from the condenser would be all dissipated in the AmbHx. By doing so, the total CCGT power output would be increased, even considering the HP electric consumption. This option is intended to be used when both, the electricity demand and ambient temperature, are high.

METHODOLOGY

Model description

The techno-economic analysis was performed in a model created by the authors using DYESOPT (a KTH in-house modeling tool) as a reference (Spelling, 2013). It consists of several thermodynamic functions and calculation scripts that based on key input design parameters such as the CCGT nominal capacity, design ambient temperature and component size factor, is able to calculate the plant performance at steady-state (nominal design) and also annually by means of quasi-steady state time-dependent calculations for given annual weather and price data files specified as input. Different TES and HP sizes were evaluated in order to find an optimum configuration that would yield the highest profits. The model is such that once the plant is designed for steady state conditions, then a time-dependent simulation takes place, in which boundary conditions such as ambient temperature and electricity price are input on an hourly basis, and the CCGT performance is analyzed under off-design conditions considering a time-step of 5 minutes, and also taking into account the conditions at the previous time-step.

Steady State Model

A 400MWe CCGT was modelled using data from IREN's facilities in Turin, Italy (IREN, 2018). At nominal conditions, the plant requires an air mass flow of 666 Kg/s at 15°C. Considering such intake conditions and aiming to lower the GT inlet temperature to 5°C, the GTHx was designed following the NTU method, better described in previous works from the authors. The AmbHx was design using the same method but considering different values since this component is intended to work under different conditions. In this case the Hx was design so that it could dissipate all the heat produced by the HP when in OM4, or continuous cooling. The TES was sized so that at the beginning of the discharge period it is capable of cooling the nominal mass flow from the design ambient temperature, 15°C, to 5°C. The HP was designed accordingly. In that way it would be able to charge the TES within approx. 2 hours.

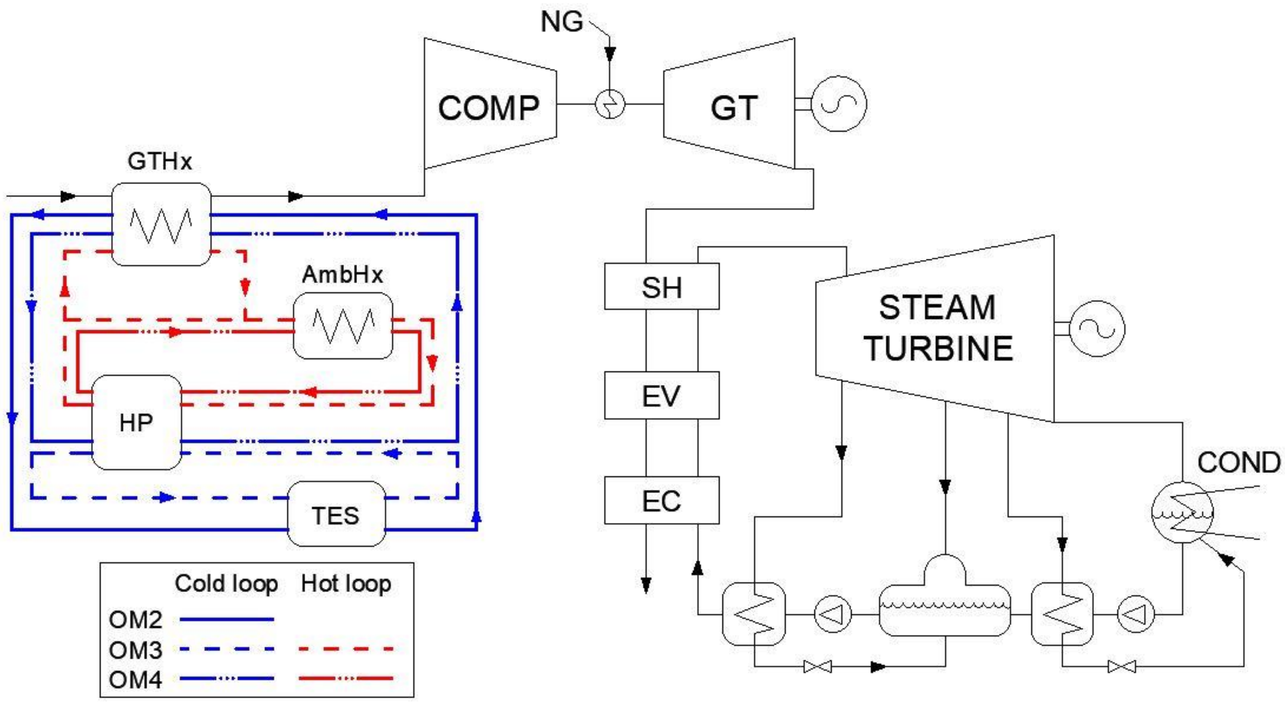

Figure 1. Simplified schematic layout of the proposed POCC integrated with HP and TES

Time-dependent Simulation

The annual simulation is based on quasi-steady state calculations that deploy switch logical conditions. These calculations were implemented in Matlab. The mean daily electricity price, the minimum daily electricity price and maximum daily electricity price define which operational mode is chosen, as explained earlier. These prices are defined for each day of the year as an on/off switch vector which the model reads to start one of the three loops: Charge, Discharge, or Continuous Cooling. In these loops, an initial value for mass flows and heat pump electrical power is given, after which functions recreated from Trnsys unit library (Solar Energy Laboratory, 2007) are used to evaluate the outputs of heat exchangers in terms of temperature. The TES outlet temperature is calculated with a function created from TES data. When it comes to ambient temperatures lower than 5°C, an anti-ice system outside of the model was considered. Its power consumption was estimated to be equal to the power of electrically heating the air up to the minimum inlet temperature requirement.

For charging, the charging temperature (out of evaporator into TES) is kept constant while mass flow is varied until maximum TES state of charge (SoC) is reached. During discharging, the mass flow is varied until the minimum SoC is reached or the desired GT inlet condition is achieved. Mass flow is changed for the next time step trying to achieve the desired GT inlet condition of 7.5°C. In this study the off-design efficiency and production is calculated based on curves provided by the plant operator (IREN, 2018).

Heat pump modeling

The heat pump unit consists of two heat balances linked to each other via a coefficient of performance. The cold side requirement is first calculated, as it is the primary reason of the system. In the calculation loop, an initial COP of 4.5 is given for the first time step in a charging or continuous cooling loop, and mass flows and temperatures are calculated based on it. In the second time step, the temperatures at condenser and evaporator outlets during previous time step are used to calculate the COP. Since a theoretical COP can become unfeasibly large if it is calculated based on temperatures alone, it was divided by a factor of 2 to achieve more reasonable values in the range of 2.5 - 7. There is a maximum ramp-up of 0.083 MW/min until the maximum HP power is reached. In OM3, the mass flow in the loop is increased until either the max ramp-up, max HP power, or max state of charge in TES is reached. In OM4, the mass flows are kept constant while HP power is gradually increased to achieve the desired GT inlet temperature.

Heat exchangers

Ambient heat exchanger and gas turbine heat exchanger were recreated from Trnsys (Solar Energy Laboratory, 2007), using mass flow, temperature and specific heat capacity of both entering fluids as inputs and giving the outputs of the same parameters. AmbHx cooling air mass flow is varied with the aim to keep condenser temperature constant. GTHx on the other hand, takes ambient temperature and constant air mass flow as inputs during each time step while either the cooling or heating fluid temperature and mass flow change according to the operation mode. A maximum GT inlet temperature caused by charging was set at 20°C; all excess heat is released in AmbHx to minimize the negative effect air heating has on power generation. At this stge. the pressure drop caused by GTHx was not accounted for in the model. This drop would have a negative impact in the performance of the plant.

TES modeling

The thermal energy storage behavior was based on a numerical model of a unit suited specifically for precooling of gas turbine inlet gas. A specific downscaled design of the thermal energy storage unit was made, from which correlations capturing the physical phenomena during charging and discharging processes were derived and then applied in the model for a larger scale system (depending on the case been investigated). The numerical model of the TES was built simulating a 5 m^3 tank with 1.9 m diameter filled with phase change material (PCM) based capsules in a compact arrangement (packing factor of 73.9%). The tank was discretized into eleven thousand columns where each column consists of 40 quarter capsules. An example of the analyzed model and capsule geometries are provided in *Figure* ***2***. Each column consists of 19500 mesh cells at mesh quality above 0.54. Assumptions are made to enhance the convergence of the model: isotropic material properties; negligible buoyancy force; laminar flow; negligible capsule thermal resistance. Enthalpy method is used here for the phase change simulation, where the material property of the PCM is based on T-History method as described by Chiu J. and Martin (2012).

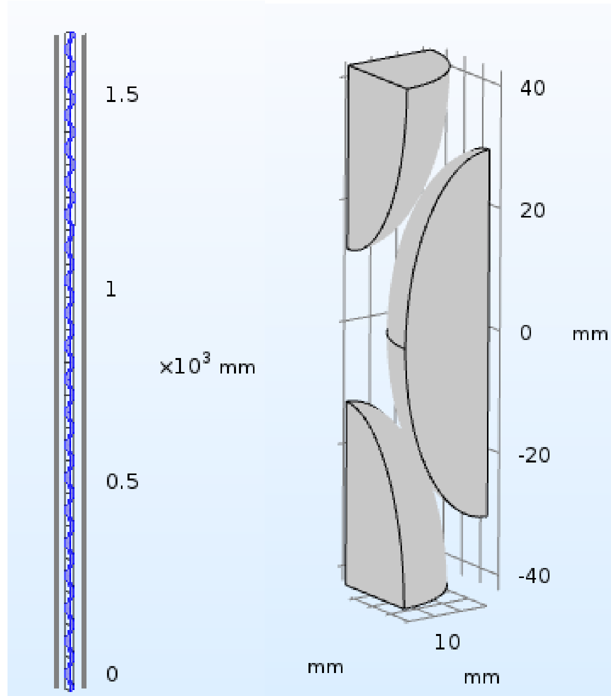

Figure 2 TES Model Geometry: Discretized Column (left), Capsule Geometry (right)

The performance curves for both charge and discharge are modeled based on two operating conditions each with three mass flows (Table 1). These flows represent the nominal, 50% and 200% of the downscaled mass flow. The operating conditions are set with constraints on the minimum outlet temperature of the heat transfer fluid (HTF) during charge and on the maximum outlet HTF temperature during discharge.

Table 1 TES modeling parameters

	Charging (Case A)	Charging (Case B)	Discharging (Max P)	Discharging (Min P)
T $TES_{initial}$ (°C)	7.8	7.8	1.8	1.8
T HTF_{inlet} (°C)	-7.5	-7.0	20.0	8.0
Constraint: T HTF_{out} °C	> -5	> -5	< 15	< 6.3
Mass flow $_{nominal}$ (kg/s)	8.58	10.3	4.06	9.54
Mass flow $_{50\%}$ (kg/s)	4.29	5.16	2.03	4.77
Mass flow $_{200\%}$ (kg/s)	17.2	20.7	8.14	19.1

THERMODYNAMIC PERFORMANCE

This section presents the model performance in terms of power output and TES state of charge. The following cases were simulated as listed in Table 2. For cases 1 and 2, the thermal energy storage capacity was kept constant to see the difference a varying heat pump capacity can make in the system. In cases 3 and 4, a similar sensitivity analysis was done with TES capacity while keeping HP power. In this way, the near-optimal layout containing both TES and HP was decided. A separate case, Case 5, considers using solely a heat pump to provide the cooling capacity during low electricity prices and high ambient temperatures.

Table 2 Simulated cases.

Case 1	
Heat pump electric power	5 MW_{el}
TES capacity	12 MWh
Case 2	
Heat pump electric power	7.5 MW_{el}
TES capacity	12 MWh
Case 3	
Heat pump electric power	5 MW_{el}
TES capacity	6 MWh
Case 4	
Heat pump electric power	5 MWel
TES capacity	18 MWh
Case 5	
Heat pump electric power	5 MW_{el}
TES capacity	-

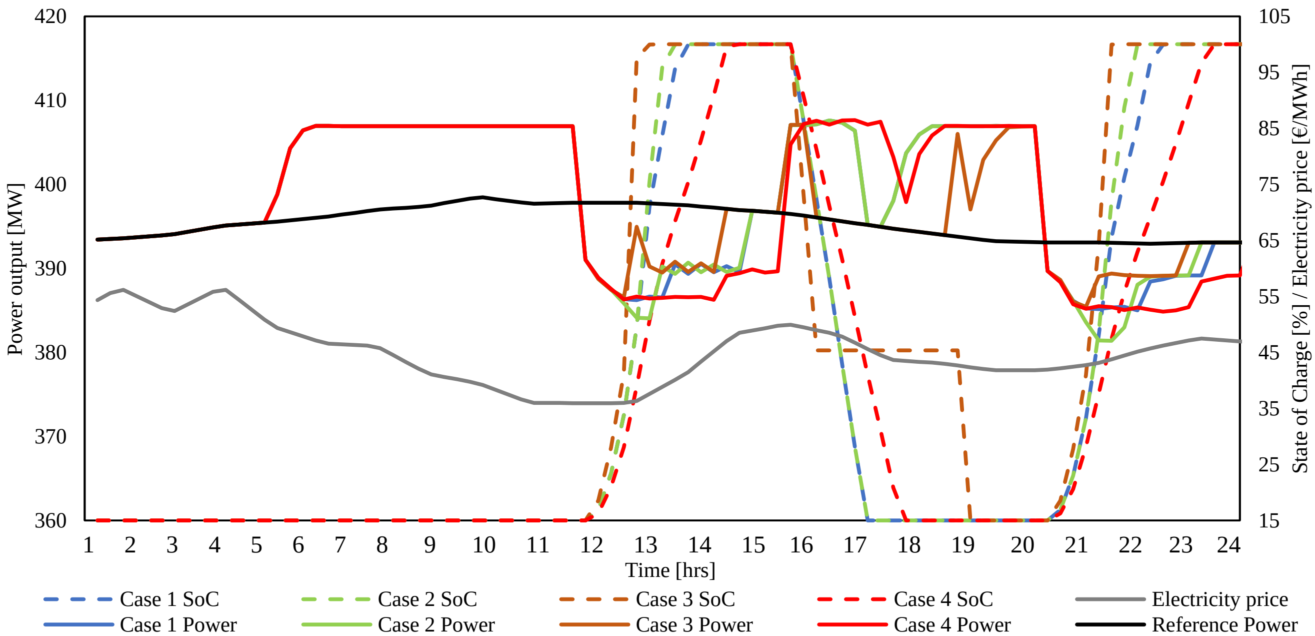

Figure 3 A day of operation

The most significant design and decision variables influencing the results are listed in *Table 3*, and a typical day of operation is shown in Figure 3. Results show that both HP size with regards to TES size and input (allowed) charging time had an impact on the utilization factor of the TES. It can be observed that keeping the heat pump capacity and design charging mass flows constant had a direct impact on the state of charge (SoC) reached after three hours of charging, which varied depending on the TES size. It can also be seen that at times of the peak electricity price the storage is fully discharged, generating more power, but at the expense of high parasitic consumption during charging.

Another observation is that there is a decrease in power output during charging due to, not only the parasitic load, but also the increased temperature at GT inlet. On the other hand, the peak achieved during maximum daily electrical price does provide a source of profit from the system, albeit only during a two-hour time window. It can also be observed that larger TES units are able to increase the electricity generated during peak hours, although they also take longer to charge. The charging and discharging mass flows become thus a decisive variable from an operating standpoint. For instance, increasing the mass flow from TES would allow for a larger peak, whereas decreasing it, or extending the charging time, would allow discharging to last for a longer period. The annual behavior is illustrated in Figure 4 where it is shown that the difference in power production is largely dependent on the season, with higher peaks in summer, although also higher parasitic loads too. In winter, the difference is minimal due to low temperatures when anti-ice is used instead. In the summer, however, the peaks and minimums of power generation are far more distinct as extreme temperature differences occur at GT inlet depending on the operating mode. The economic analysis performed in this study aimed to find the benefit of operating the system in this manner

In the case of Turin, the electricity price has two distinctive daily peaks which were utilized, increasing the possibility of profiting from both price variations. However, as the results show, the decrease in power production during low electricity price is still larger than the power increase during peak. This directly leads to technical KPIs which are lower than those for the nominal plant. The limitation of charging within three hours means using a large mass flow which in turn causes high GT inlet temperature and low power outputs. Longer time periods with low electricity price (longer charging period), or alternatively smaller TES capacity, would allow avoiding these peaking temperatures from occurring frequently.

Table 3. Variables used for the model runs.

Variable	Value
Charging mass flow, design (kg/s)	500
Discharging mass flow, design (kg/s)	300
Continuous cooling mass flow, design (kg/s)	500
Hours of charging	3
Charging inlet temperature to TES	-7.47°C
TES minimum state of charge	15 %

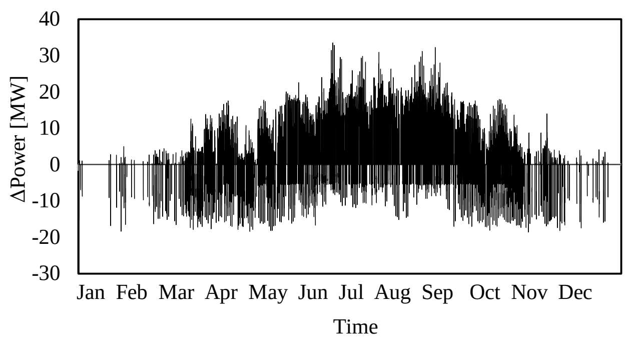

Figure 4 Power difference between POCC and nominal plant.

TECHNO-ECONOMIC ANALYSIS

The method to assess the economic performance of the CCGT configurations proposed is presented in this section. As expected, the required investment cost varied as a function of the size of the added components. The investment costs of the combined cycle and the IIC units have been evaluated through cost-scaling functions and references found for the CCGT plant, the HP, key HXs and the TES (Song et al, 2017)(Chiu, 2011)(EIA, 2018). The annual O&M cost is estimated as the sum of the power block maintenance, labor and fuel costs. The power block annual maintenance cost is determined at 3% of the total capital costs. The decommissioning cost is taken as 5%. The discount and insurance rates are taken as 6% and 1%, respectively. The thermo-economic performance analysis has been estimated using the following formulas:

The equation for calculating the capital costs is as follows, combining the equipment costs with civil works costs, installation, contingency, engineering as well as decommissioning costs:

$$CAPEX = C_{CC} + C_{GTHx} + C_{AmbHx} + C_{pump} + C_{pipe} + C_{TES} + C_{HP} + C_{civil} + C_{inst} + C_{cont} + C_{eng} + C_{decomm}$$

The respective equations used for estimating the costs are presented in *Table 4*. Unless otherwise stated, the costs functions are taken from DYESOPT default cost functions. C_{equip} only consists of the equipment costs from Combined Cycle to HP, while C_{plant} includes additionally civil works and installation.

Table 4 Capital costs

Type of cost	Equation [€]
Combined Cycle	$C_{CC} = 978 \cdot P_{CC,nominal} \cdot 1.24245$ (U.S. Energy Information Administration, 2016)
GTHx	$C_{GTHX} = 0.063 \cdot P_{GTHX,max}$ (Spelling, 2013)
AmbHx	$C_{AmbHX} = 0.063 \cdot P_{AmbHX,max}$ (Spelling, 2013)
Pump	$C_{pump} = n_{pump} \cdot 940 \cdot P_{pump}^{0.71} \cdot (1 + 0.2/(1 - \eta_{pump}) \cdot 1.24245$ (Spelling, 2013)
Piping	$C_{pipe} = 658 \cdot \dot{m}_{pipe}^{1.2} \cdot 1.24245$ (Spelling, 2013)
TES	$C_{TES} = 143700 \cdot \left(\frac{E_{TES}}{E_{TES,Ref}}\right)^{exp}$
HP	$C_{HP} = 1580 \cdot \left(\frac{P_{HP,el}}{P_{HP,el,Ref}}\right)^{exp}$ (Song, 2017)
Civil	$C_{civil} = 21.2 \cdot 10^6 \cdot \left(\frac{P_{CC,nominal}}{129.4}\right)^{0.8} \cdot 1.24245$ (Spelling, 2013)
Contingency	$C_{cont} = 10\% \cdot C_{plant}$ (Spelling, 2013)
Installation	$C_{inst} = 20\% \cdot C_{equip}$ (Spelling, 2013)
Engineering	$C_{eng} = 5\% \cdot C_{plant}$ (Spelling, 2013)
Decommissioning	$C_{decomm} = 5\% \cdot C_{plant}$ (Spelling, 2013)

OPEX costs are specified in *Table 5*.

Table 5 O&M costs

Type cost	Equation
Fuel	0.0177 €/kWh
Maintenance	$4\% \cdot C_{civil} + 3\% \cdot C_{CC}$ (Spelling, 2013)
Labor	$C_{labor} = 998\,310$ €$/a$ (Spelling, 2013)

The equation used for calculating the levelized cost of electricity (LCOE) includes investment, NG cost, operation and maintenance (O&M) costs, and an utilization rate (Eia 2018):

$$LCoE = \frac{\alpha * C_{inv} + \beta * C_{decom} + C_{oper} + C_{maint} + C_{labour}}{E_{el,net}}$$

$$\alpha = \frac{(1+i)^{n_{cons}} - 1}{n_{cons} * i} * \frac{i * (1+i)^{n_{oper}}}{(1+i)^{n_{oper}} - 1} + K_{ins}$$

$$\beta = \frac{(1+i)^{n_{dec}} - 1}{i * n_{dec} * (1+i)^{n_{dec}-1}} * \frac{i}{(1+i)^{n_{oper}} - 1}$$

K_{ins}: insurance rate [1%]
i: interest rate [6%]
n_{oper}: plant operation time [25 years]
n_{cons}: plant construction time [3 years]
n_{dec}: plant decommissioning cost [5%]
C_{inv}: investment costs - $C_{CCGT} + C_{HXs} + C_{HP} + C_{TES}$

The net present value (NPV) and discounted payback time (PBT) of the power-oriented plant are calculated as follows. Annual incomes by implementing the combined cycle gas turbine with heat pump and thermal storage are estimated based on total annual income coming from production of electricity after operation and maintenance costs were subtracted. The net present value for the project is estimated by (Nadir, Ghenaiet, and Carcasci 2016):

$$NPV = -\beta C_{inv} + \sum_{t=1}^{n}(\frac{I_{Tot} - C_{O\&M}}{(1+i)^t})$$

I_{Tot}: Total annual income [€/year]
$C_{O\&M}$: Operation and maintenance cost [€/year]
n: Average service life [25 years]
C_{inv}: Total investment cost [€]

With a capital charge factor:

$$\beta = \frac{i(1+i)^n}{(1+i)^n - 1}$$

PBT of the project is calculated by (Mohan et al. 2014):

$$PBT = \frac{\ln(B - C_{O\&M}) - \ln((B - C_{O\&M}) - i * C_{inv})}{\ln(1+i)}$$

B: annual income from electricity generation [€]

The internal rate of return is calculated as a discount rate that makes the net present value equal to zero. Thus, the formula is solved for r and the solution is IRR.

$$IRR = r \; when \; \sum_{t=1}^{n}\left(\frac{B - C_{O\&M}}{(1+r)^t}\right) - C_{inv} = 0$$

RESULTS AND SENSITIVITY ANALYSIS

Reference plant KPIs can be seen in Table 6. The reference plant, in this case, refers to a power-oriented combined cycle power plant where only the anti-ice system and normal operation are included. Otherwise the principle is the same; the power plant is operated at 100% load and produces maximal power output without thermal power.

Table 6 Reference Plant KPIs

KPI	Value
Technical	
Total electricity	3498 GWh_{el}
Mean power output	399.32 MW_{el}
Mean efficiency	58.07 %
Economic	
NPV	771 M€
PBT	16 years
LCOE	52.71 €/MWh_{el}
IRR	2.74 %

The reference costs for the TES and HP has been found in the available literature (Chiu 2011) (Song and Wallin 2017). While the fuel costs is kept as 17.7 €/MWh (the current mean NG price in Italy (ENEA 2018)). The technical KPIs, namely nominal power output and efficiency, were re-calculated accordingly with the variation of TES and HP sizes as it is shown in Table 7. All of the selected cases exhibit an increased power production and efficiency as compared to the reference case.

Table 7 Technical KPIs

	Total electricity (GWh_{el})	Mean power (MW)	Mean efficiency (%)
Reference	3498	399.32	58.07
Case 1	3508	400.41	58.23
Case 2	3508	400.49	58.24
Case 3	3509	400.53	58.25
Case 4	3507	400.33	58.22
Case 5	3523	402.20	58.49

Table 8 Economic KPIs

	NPV (M€)	PBT (years)	LCOE (€/MWh)	IRR (%)
Reference	771	16	52.71	2.48
Case 1	774	17	53.45	1.98
Case 2	774	17	53.57	1.90
Case 3	775	17	53.17	2.15
Case 4	773	18	53.72	2.08
Case 5	783	16	52.79	2.44

Similarly, the economic KPIs, i.e. the NPV, the PBT and the LCoE, were also computed. The economic KPIs for each case can be seen in Table 8. From the comparison between cases, it was decided to use the payback time along with net present value as measurements to choose the best cases to run sensitivity analysis on. Case 3 with a 5 MW_{el} HP and 6 MWh thermal energy storage was deemed the best case with the proposed TES+HP layout. Case 5, with only the heat pump installed, was the case with the largest NPV and shortest payback time and was therefore also additionally studied. If, as is commonly the case in the EU, the power plant is operated as a mid-merit plant (60% of the time) and generates power only when electricity price is high enough (>48 €/MWh), the payback time is increased by approximately two to three years, while the LCOE is increased by 9 €/MWh and NPV decreased by 10%. The same effect occurs on the reference plant as well, and it can be thus said that it is preferable to maximize the capacity factor and operate the plant as much as possible annually. Shutting down the plant abruptly when electricity price is low and starting it again after one hour of off-time due to higher price only occurs 0.6% of the time, and may only lead to minor errors in the model reliability. *Figure* **5** depicts the breakdown of CAPEX with values in millions of euros.

A sensitivity analysis was carried out with respect to the key design decision variables and most influencing boundary conditions e.g. electricity price, as well as the NG fuel costs. A multiplier in the range between 0.5 and 1.5 was used to vary the electricity price. The letters A, B, and C refer to cost scaling factors of 1, 0.9, and 0.8 respectively. This sensitivity tests the unit's rigidity in various electricity markets. The internal rate of return suggests that in the current Italian electricity market, the cases with linear scaling are not competitive against the reference case. However, as is expected, using a cost exponent to scale down the cost leads to increases in the IRR and Case 5B becomes cost effective in comparison. Nonetheless, as electricity price is increased, the reference case stays the most profitable case in terms of IRR. In addition to the electricity price, a sensitivity with regards to the fuel price was also carried. The fuel price was varied with by means of using a multiplier, 1.25 and 0.75. Table 10 shows the results from a sensitivity analysis performed with regards to the fuel price (FP).

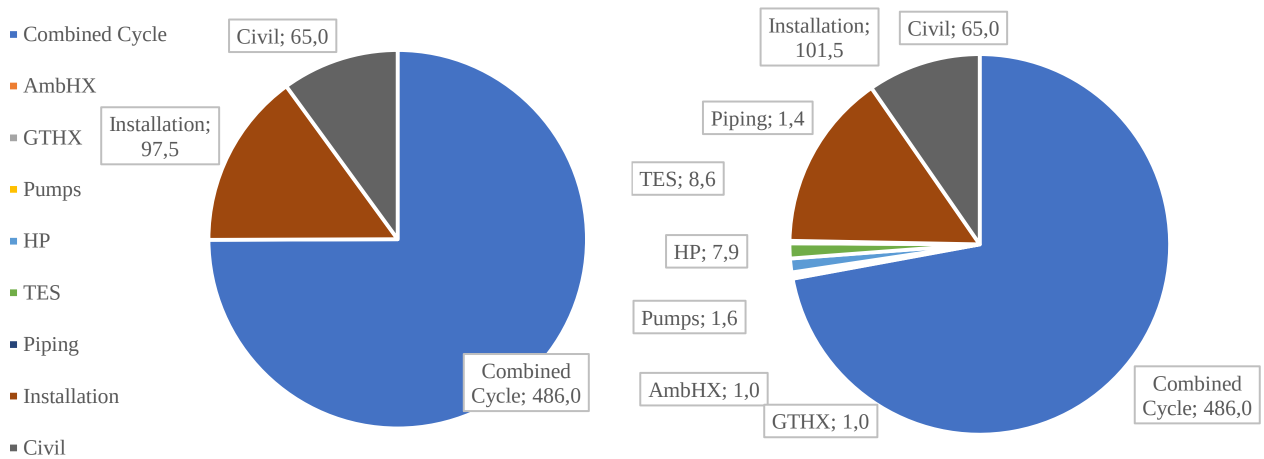

Figure 5 CAPEX breakdown of the reference plant (left), and Case 3 (right)

Table 9 Sensitivity analysis with electricity price.

Reference	Normal price	1.25	1.5	0.75	0.5
NPV (M€)	771	1,375	1,979	167	-437
PBT (a)	16	8	5	-	-
LCOE (€/MWh)	52.71				
IRR (%)	2.48	10.18	17.27	-8.55	-
Case 3A					
NPV (M€)	775	1,381	1,986	170	-436
PBT (a)	17	8	5	-	-
LCOE (€/MWh)	53.17				
IRR (%)	2.15	9.65	16.53	-8.65	-
Case 3B					
NPV (M€)	776	1,382	1,987	170	-435
PBT (a)	16	8	5	-	-
LCOE (€/MWh)	52.94				
IRR (%)	2.30	9.87	16.83	-8.56	-
Case 3C					
NPV (M€)	776	1,382	1,987	171	-435
PBT (a)	16	8	5	-	-
LCOE (€/MWh)	52.82				
IRR (%)	2.38	9.99	17.00	-8.52	-
Case 5A					
NPV (M€)	783	1,390	1,998	176	-431
PBT (a)	16	8	5	-	-
LCOE (€/MWh)	52.79				
IRR (%)	2.44	10.04	17.04	-8.38	-
Case 5B					
NPV (M€)	784	1,391	1,998	176	-431
PBT (a)	16	8	5	-	-
LCOE (€/MWh)	52.58				
IRR (%)	2.49	10.13	17.16	-8.35	-
Case 5C					
NPV (M€)	784	1,391	1,998	176	-431
PBT (a)	16	8	5	-	-
LCOE (€/MWh)	52.49				
IRR (%)	2.55	10.22	17.28	-8.32	-

Table 10 Sensitivity analysis with electricity price.

FP 1.25	Ref.	Case 3A	Case 3B	Case 3C	Case 5A	Case 5B	Case 5C
NPV (M€)	430	435	435	436	443	443	443
PBT (y)	-	-	-	-	-	-	96
LCOE (€/MWh)	60.33	60.76	60.54	60.42	60.36	60.14	60.05
IRR (%)	-2.79	-2.99	-2.88	-2.82	-2.72	-2.68	-2.63
FP 0.75							
NPV (M€)	1,111	1,116	1,117	1,117	1,124	1,125	1,125
PBT (y)	10	10	10	10	10	10	10
LCOE (€/MWh)	45.09	45.57	45.34	45.23	45.23	45.01	44.92
IRR (%)	6.95	6.50	6.69	6.79	6.83	6.90	6.98

CONCLUSIONS

A techno-economic model of an innovative CCGT integrated with an inlet GT mass flow pre-cooling loop consisting of a heat pump and a cold thermal energy storage unit has been developed and used to evaluate the feasibility of such a concept. The proposed layout is shown to increase the power output of a CCGT during times of peak electricity prices and at high ambient temperatures. This comes at the expense of significantly decreasing the power during off-peak hours, limiting the economic benefit of the system (due to the required charging and HP consumption). The study shows that, for the cost assumptions undertaken and for the specific market considered, the integration of such a system is not viable as it would be less profitable than building a conventional CCGT. Nevertheless, it is shown that depending on the difference between peak electricity price and off-peak prices then the system could be profitable, being thus highly dependent to the evolution of electricity prices in the market itself. For instance, a market with higher price volatility and more pronounced peaks would potentially justify the investment. The latter though, is highly dependent on the evolution of both demand and new type of generation technologies integrated into such a system, which is hard to predict. Specifically, for the study case considered in the study, a price multiplier of 1.5 would allow justifying the required investment for the pre-cooling system. Additionally, one clear benefit of integrating the pre-cooling system is that it adds more flexibility to the operation of the plant. Such flexibility benefits were not explicitly quantified in this analysis. Finally, as both the operating regime and respective control logic implemented, as well as the cost assumptions, play an important role in the results, a subsequent sensitivity analysis with regards to such assumptions is also recommended. The last refers to reviewing the underlying assumption that the reference CCGT would operate continuously as the results might have differed if a mid-merit operation was instead considered, in which the reference plant is recruited by the market to only reach a capacity factor of approximately 50%, and then the added pre-cooling equipment could potentially enhance the profitability even further.

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NOMENCLATURE

AmbHx: Ambient heat exchanger
CCGT: Combined cycle gas turbine
GTHx: Gas turbine heat exchanger
HP: Heat pump
HTF: Heat transfer fluid
IIC: Integrated inlet conditioning
IIR: Internal rate of return
KPI: Key performance indicator
LCOE: Levelized cost of electricity
NG: Natural gas
NPV: Net present value
OM: Operating mode
PBT: Payback time
POCC: Power-oriented combined cycle
SoC: State of charge
TES: Thermal energy storage

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