The Future of Gas Turbine Technology
9th International Gas Turbine Conference
10-11 October 2018, Brussels, Belgium

Paper ID Number: 54-IGTC18

INTEGRATION OF HEAT PUMP AND GAS TURBINE COMBINED CYCLE: LAYOUT AND MARKET OPPORTUNITY

Andrea Giugno*, Alessandra Cuneo*, Luca Piantelli**, Alessandro Sorce*
* Thermochemical Power Group - DIME, Università degli Studi di Genova, Via Montallegro 1, 16145, Genova, Italy
**Innovation Department, IREN, Corso Svizzera 95, 10143, Torino, Italy

Via Montallegro 1, 16145, Genova, Italy
+390103532463
andrea.giugno@edu.unige.it

ABSTRACT

The increase share of non-dispatchable renewables envisaged in the generation mix of Europe requires conventional plants to take on additional tasks. A higher flexibility of natural gas fired Combined Cycle (CC) power plants, which are currently the backbone of EU electrical grid, has become mandatory.

To increase the flexibility, and to further enhance turn-down ratio and power ramp capabilities of power-oriented CCs, an innovative concept based on the coupling of a highly efficient heat pump (HP) with CCs is proposed, featuring thermal storage and advanced control concept for smart scheduling.

A preliminary analysis of this integrated system is performed, evaluating the feasibility and the economic sustainability, along with the economic competitiveness with actual Combined Heat and Power plants, based on the analysis of the Energy Market trend.

INTRODUCTION

In recent years the European Union set itself the objective of becoming a resource-efficient and more competitive low carbon economy and society by 2050. One of the main challenges that EU is facing is to enable the rapid growth in renewable energy and to substitute carbon-intensive fossil fuels and strengthen Europe's competitiveness (EEA - European Environment Agency ,2017).

Government incentives have supported the increased use of renewables and have contributed to ensure that renewable energies are the fastest growing source of electricity generation in Europe. The EU power generation mix changes considerably over the projected period in favour of renewables (Figure 1). Before 2020, this occurs to the detriment of gas, as strong renewables policy to meet 2020 targets, very low coal prices compared to gas prices. In addition, low CO_2 prices do not help the shift from coal to gas. After 2020, the change is characterized by further renewables deployment, but also a larger coal to gas shift, driven mainly in anticipation of increasing CO_2 prices.(EU commission, 2016).

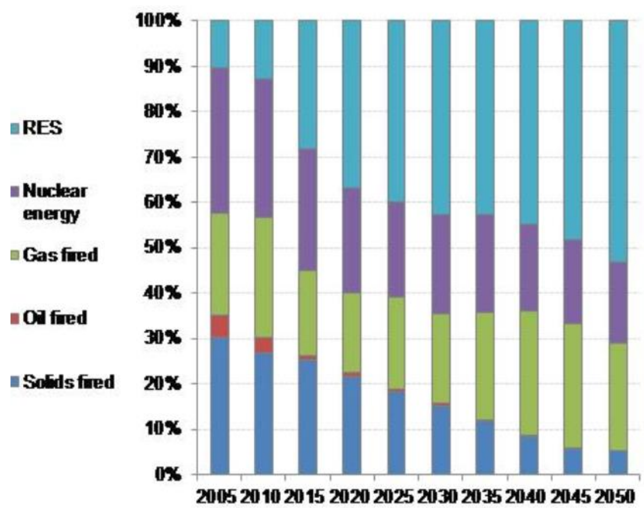


Fig. 1: EU power generation (net) by fuel(EU commission, 2016)

However, the RES production results extremely variable hour-by-hour, since is a non-programmable stochastic resource, demanding conventional plants to take on additional tasks and to have a higher flexibility in order to provide regulation services to the grid. This affects particularly natural gas fired Combined Cycle (CC) power plants, which are currently the backbone of EU electrical grid and are foreseen by the EU as the bridging technology (till the horizon of the 2050) to a decarbonized scenario, thanks to their reduced carbon footprint and fast response in terms of grid stabilization (European Commission ,2011).

On the other hand, power market evolution is heavily influencing thermal generation: load factor and annual efficiency reduce, number of start-up increases, with a direct effect on the profitability of assets, often leading to mothballing or closure of these plants. Figure 2 highlights the problem referring to some European Countries: in particular the Italian Average Efficiency of the production portfolio dropped from 55% to 50% over 10 years (ARERA, 2016; Departement of Energy & Climate Change ,2015; Ecofys ,2014). This is an important indication since Italian electrical production mainly rely on gas, for 35% of the total (ARERA, 2016).

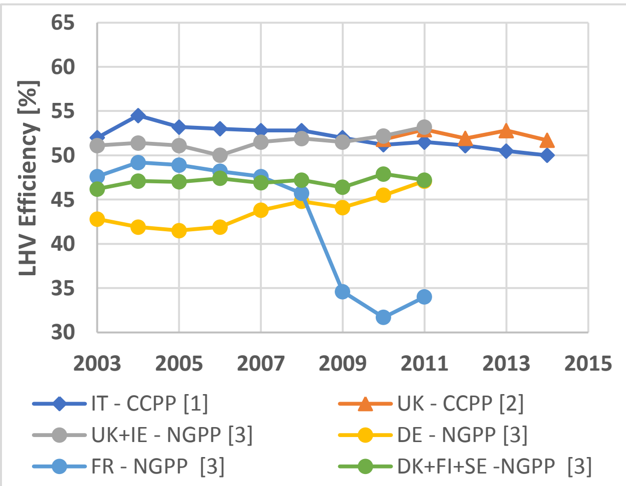


Fig. 2: Average CC efficiency per country (2003-2014) (Autorità di Regolazione per Energia Reti e Ambiente [1], Department of Energy & Climate Change [2], Ecofys [3])

Some Gas-fired assets will be able to survive via more operative flexibility, which can lead to ancillary service revenues, more attractive by the energy utility perspective in the present scenario. While Gas Turbine (GT) and CC Original Equipment Manufacturers (OEMs) struggle to maintain their market share, Combined Cycle power plant operative flexibility was addressed until now within the seasonal constraints and the flexibility in the time domain was mainly investigated taking into account the impact over the Bottoming Cycle equipment (Rossi et al, 2017) or considering Smart-Grid arrangement including co-generative and tri-generative solutions (Rivarolo et al., 2016).

Moreover the adoption of electrical storage was proposed to restore CCs sustainability and profitability with a gain for both energy utilities and the GT OEMs, mainly to integrate a continuous grid support service in peaking open cycle unit (General Electric 2016), introducing also Black Start capabilities (Siemens ,2016).

An innovative concept based on the coupling of a fast-cycling highly efficient Heat Pump (HP) with the CCs is here proposed, featuring Thermal Energy Storage (TES) as thermal and equivalent electric storage. The integration of TES in such complex system requires a deep knowledge of TES dynamic response (Mahmood et al, 2018) and a reliable evaluation of the state of charge (Ferrari et al, 2017).

In the following chapters the main effects of the integration of the heat pump with a Combined Cycle are evaluated and so a preliminary analysis on the feasibility and economic sustainability of this integrated plant, along with the economic competitiveness with actual Combined Heat and Power (CHP) plants, based on the analysis of the Energy Market trend and opportunities.

NOMENCLATURE

$\mathrm{COE}_{year,i}$	Cost of Electricity referred to i-th year [€/MWh]
C_{gas}	Natural Gas Cost [€/MW]
C_{CO2}	CO_2 Cost [€/ton]
CC_{sh}	Share of thermal energy between heat pump and combined cycle [-]
$C_{th_{j,k}}$	Cost of thermal energy production with the *k*-th heat pump for the corresponding *j*-th fraction of PUN considered [€/MWh]
$C_{O\&M,fix}$	Fix O&M costs [k€/MW-year]
$C_{O\&M,var}$	Variable O&M costs [€/MWh]
$C_{O\&M,year}$	Annual total O&M cost [k€/MW]
H_j	Number of hours during which the i-th fraction of PUN occurs [hours]
h_{eq}	Equivalent hours [hours]
P_{CC}	Net Nominal Combined Cycle Power [MWe]
P_{inst}	Gross Power installed [GW]
E_{prod}	Gross Energy produced [GWh]
$P_{th,HP}$	Heat Pump thermal power [MWth]
η_{plant}	Plant efficiency [%]
$\theta_{gas}^{CO_2}$	NG CO_2 emission factor [kgCO_2/GJ]

Acronyms

CC	Combined Cycle
CCPP	Combined Cycle Power Plant
CHP	Combined Heat and Power
COE	Cost of Electricity
COP	Coefficient of Performance
DHN	District Heating Network
EU	European Union
GT	Gas Turbine
HOB	Heat Only Boiler
HP	Heat Pump
IIC	Integrated Inlet Conditioning
EFOR	Equivalent Forced Outage Rate
LHV	Lower Heating Value
MEL	Minimum Environmental Load
MGP	Day-Ahead Market
NG	Natural Gas
NGPP	Natural Gas Power Plant
OEM	Original Equipment Manufacturers
O&M	Operations and Management
PHCC	Pump-Heat Combined Cycle
PO	Power Oriented
PUN	National Single Price

PV Photovoltaic System
RES Renewable Energy Sources
TES Thermal Energy Storage

ITALIAN ENERGY MARKET OVERVIEW

The diffusion of RES has modified significantly the profile price on the Day-Ahead Market (MGP) all over the EU; in particular by analyzing the Italian Market (Fig. 3) it is possible to highlight the main effects of RES increase share in the generation mix, which is however similar in most of EU countries (Autorità di Regolazione per Energia Reti e Ambiente ,2016):

- Until 2010, when photovoltaic system installation was not so relevant, the highest prices occurred during day hours, corresponding to the peak load demand hours.
- From 2012, the highest prices are in the early evening hours (17-21), when PV production progressively gets lower. On the contrary, during central hours of the day, when PV production is maximum, and the residual energy demand is consequently lower, the price is minimum.
- The ratio between the average hourly National single price (PUN) and the annual average PUN has considerably decreased between 2008 and 2016, as the PUN itself is related with the gas cost.
- In 2017 instead there has been an increase of both PUN and gas cost.

Calculating an approximated Cost of Electricity (COE) for a 400 MW Combined Cycle and its variation along the years between 2010 and 2016, it is possible to identify more accurately the profitability and sustainability of such a CCGT, when compared with PUN price distribution (Figure 3).

The constants used for the calculation are reported in the following table and mainly taken from (RSE SpA, 2016) and are referred to 2015, while Gas and CO_2 Cost, CC average effiency and equivalent operating hours are variable per year.

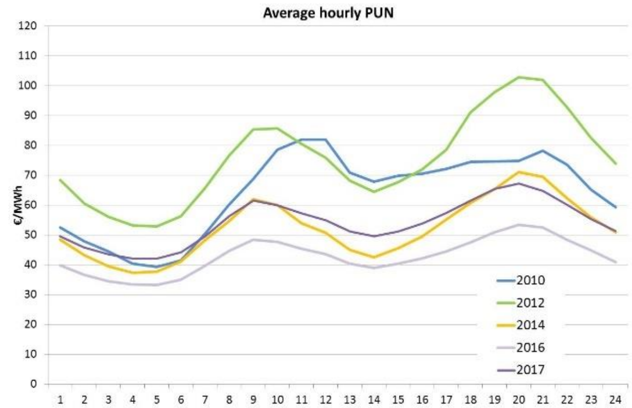


Fig. 4: Average hourly PUN variation in Italy along the years (2010-2017) (ARERA ,2016)

Tab. 1: 400MW CC plant data for COE calculation

	Unit of measure	*Value*
Net Nominal Power	MWe	400
Investment Costs	k€/MW	650
Annual total O&M	% of investment costs	3.5
Fix O&M costs	k€/MW-year	10.5
Variable O&M costs	€/MWh	3.15
Construction time	Years	3
Useful lifespan	Years	20

The efficiency has been considered between 50% and 55%, which is a bit lower compared to power plants state-of-art (beyond 60%), but it is representative of the off-design condition of the real plant exercise, as shown in figure 2.

As concerns instead the natural gas costs, an yearly mean of the historical data of Italian market has been used (Gestore Mercati Energetici ,2010-2016), as reported in the following, along with the equivalent working hours per year of the plant calculated as the ratio between the gross energy produced from Power-Only and CHP Combined Cycle, during the year considered, and the corresponding installed gross power (TERNA ,2016).

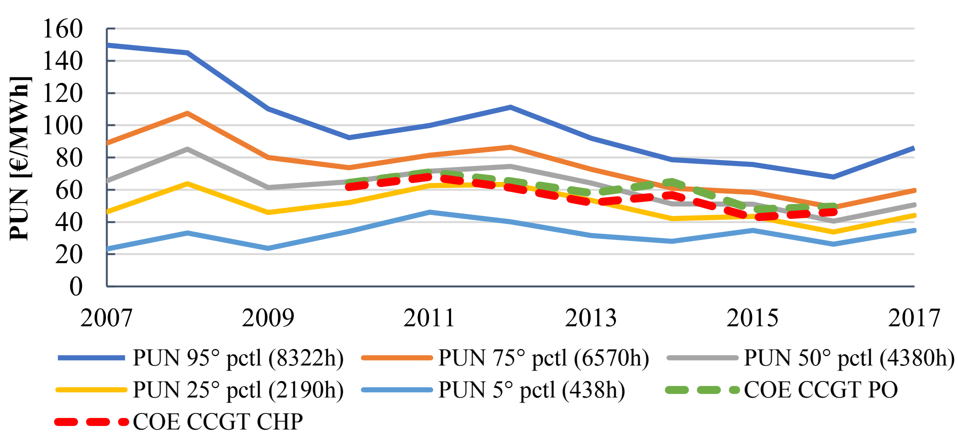


Fig. 3: CHP and PO CC COE and PUN variation along the years (2007-2017)

Tab. 2: PO and CHP CCs in Italy - gross power installed vs gross energy produced along the years (2010-2016)

Years	*PO-CC P_{inst} [GW]*	*PO-CC E_{prod} [GWh]*	*CHP-CC P_{inst} [GW]*	*CHP-CC E_{prod} [GWh]*
2010	23.05	62568.3	16.54	94257.8
2011	25.01	64594.6	15.95	84327.7
2012	25.93	52214.2	16.26	82433.3
2013	25.22	37764.1	15.70	69139.4
2014	25.13	28943.3	15.76	60932.0
2015	22.61	36052.6	17.68	69424.5
2016	21.82	46213.8	17.74	77856.6

As it is noticeable from Tab. 2, there has been a drop after 2014 in the gross power installed (P_{inst}) for power oriented combined cycle, because of the shutdown of several of them due to their low flexibility and profitability connected to the market situation. As concerns CHP CCs the gross power installed has undergone small changes over the years considered, with a slight increase in the last four years due to an increase of the thermal demand, impacting also the equivalent hours of such kind of plant (Tab. 3).

Tab. 3: Gas and CO_2 Cost and equivalent hours of 400MW CC plant per year (Gestore dei Servizi Energetici ,2017; Gestore Mercati Energetici ,2018)**.**

Years	*Gas Cost [€/MWh]*	*h_{eq} PO-CC*	*h_{eq} CHP-CC*	*CO_2 Cost [€/ton]*
2010	25.86	2700	5700	14.00
2011	29.46	2600	5300	13.00
2012	26.81	2000	5100	7.37
2013	22.19	1500	4400	4.47
2014	23.85	1150	3900	5.97
2015	16.54	1600	3900	7.67
2016	18.97	2100	4390	5.12
2017	21.25	-	-	7.00

Data of equivalent hours for 2017 have not been published yet.

The COE has been calculated (eq. 1) for a reference CHP and PO CC considering data enlisted in Tab.1 and Tab. 3 and then compared with the PUN percentile variation along the years in Fig. 3.

$$\begin{aligned} \mathrm{COE}_{year,i} &= \frac{C_{gas,i}}{\eta_{plant,i}} + C_{O\&M,fix} + \\ &+ \left(C_{O\&M,var} + C_{O\&M,year}\right)\frac{P_{CC}}{h_{eq,i}} + \\ &+ \left(\theta_{gas}^{CO_2} * \frac{3600}{\eta_{plant,i} * 10^6} * C_{CO2,i}\right) \end{aligned} \quad (1)$$

Where the last term between brackets of the equation has been used to bring the cost of CO_2 in €/MWh and $\theta_{gas}^{CO_2}$ is the emission factor (55.873 $kgCO_2$/GJ), calculated by ISPRA 2016 as the average of the emissions of the 2013-2015 period.

As it is possible to observe in Fig. 3 the PUN has suffered a reduction over the years; causing a reduction of the operating hours and so of the profitability of power generation and then to the CCGT cycling. This can lead to an increase of failure rates and so to higher plant equivalent forced outage rates (EFOR) and higher capital and maintenance costs to replace components at or near the end of their service lives (Benato et al. ,2016).

HEAT PUMP INTEGRATED SYSTEM

To improve Combined Cycles flexibility, to increase their yearly efficiency and to give mothballed CC and GT plants a second chance to be profitable on the market again, the integration of a fast cycling Heat Pump with a CC is proposed, featuring cold/warm thermal energy storage (TES).

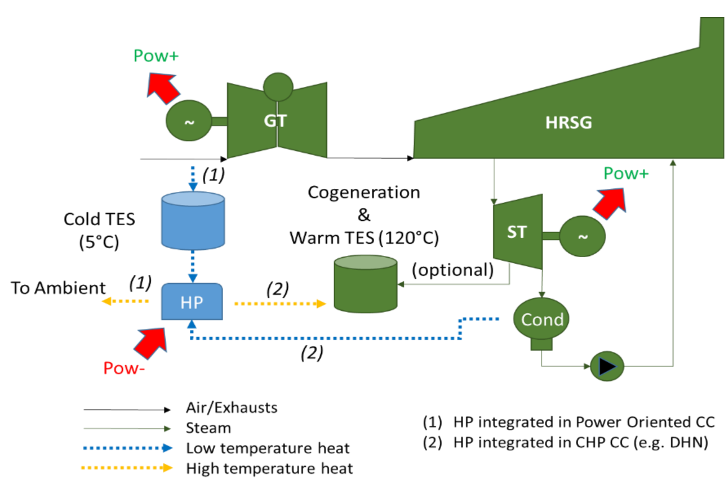
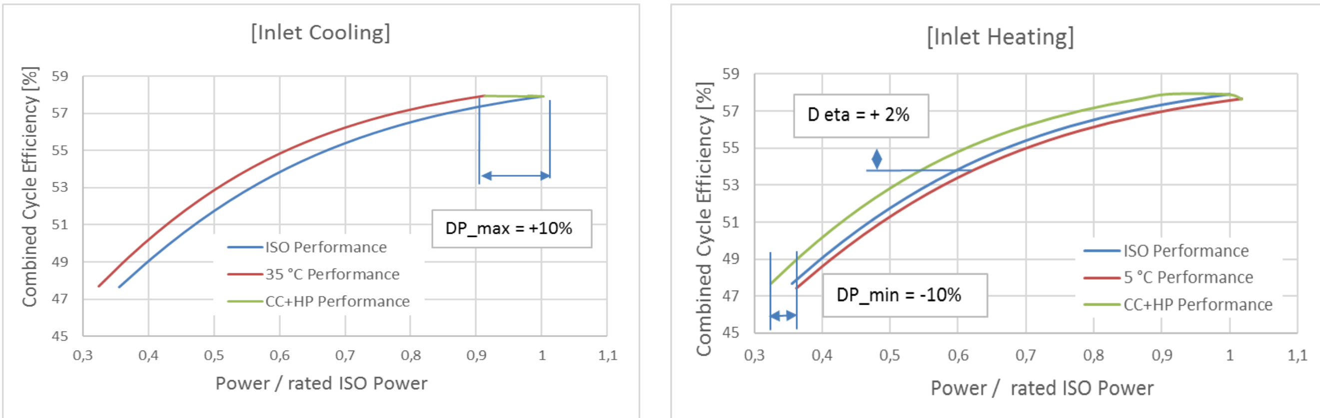


Fig. 5: Integrated system HP-TES-CC concept scheme



(a) **(b)**

Fig. 6: (a) Peak: Inlet Cooling, (b) Off-peak: Inlet Heating

Power Oriented Combined Cycle

Power oriented (PO) layout (Fig. 5(1)) introduces a new Integrated Inlet Conditioning (IIC) system, to increase yearly efficiency and CCs production.

The IIC concept is proposed both for cooling, increasing the maximum power output of the CC using the cold TES (OP1 in Fig. 7), and both for heating, increasing the part-load efficiency and reducing minimum environmental load (MEL), defined as the minimum load at which the machines can be exercised while respecting the pollution limits (OP2 in Fig. 7).

The heat pump can operate also with CC off, acting as a Smart Load during the period of high RES production /low electricity price. So, the main weakness of the HP solution over a traditional Absorption Chiller, i.e. the higher electrical power consumption, becomes in this layout one of its advantages.

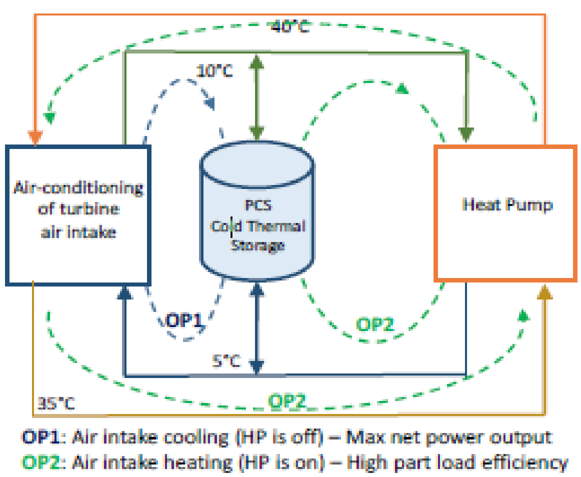


Fig. 7: Operating solutions for PO CC

Thanks to the introduction of TES, the cooling energy provided by the heat pump can be stored and used during the late afternoon ramp and electrical peak.

As side but beneficial effect for the IIC concept, during the off-peak periods if the CC is on (typically at part-load), the heat released by the HP can be used to heat-up the GT intake, increasing the part-load efficiency of the combined cycle of about 2% as average and reducing the MEL of 10%. The increase of the CC efficiency at higher GT inlet temperature, for part load operation, is due to two main factors:

- the positive contribution of the bottoming cycle at higher inlet temperature, which balances the GT efficiency reduction, leading to quite flat CC efficiency (usually a maximum is observed around 25°C)
- the use of inlet heating as first control strategy for part-load: the reduction of the air mass flow rate is obtained by reducing the density instead of closing the IGV (increasing the associated losses)

Fig. 6 presents the performance of this solution compared with a CC at ambient conditions for summer [35°C] (a) and winter case [5°C] (b), representing the two extreme operating conditions. The curves reflect the typical behavior of a gas turbine combined cycle and are based on a 1+1 combined cycle of 400MW electrical power.

Between these two ambient temperature extremes, the IIC acts mainly as a closed system, without waste energy conveyed to the external environment:

- during off-peak hours (OP2) while the HP charges the cold TES, the heat released by the HP is used for inlet heating, increasing the efficiency of 2%, and decreasing the MEL (-10%).
- during peak hours (OP1) the HP shut off and the TES is discharged to the inlet coil increasing the maximum power output (P_max) by about 10%.

The preliminary analysis has been performed evaluating just the effect of air temperature, while all the others external parameter, as well as the condenser pressure, remain unchanged.

The PO CC equipped with the IIC can:

- Deliver the maximum capacity during the summer electrical demand peak;

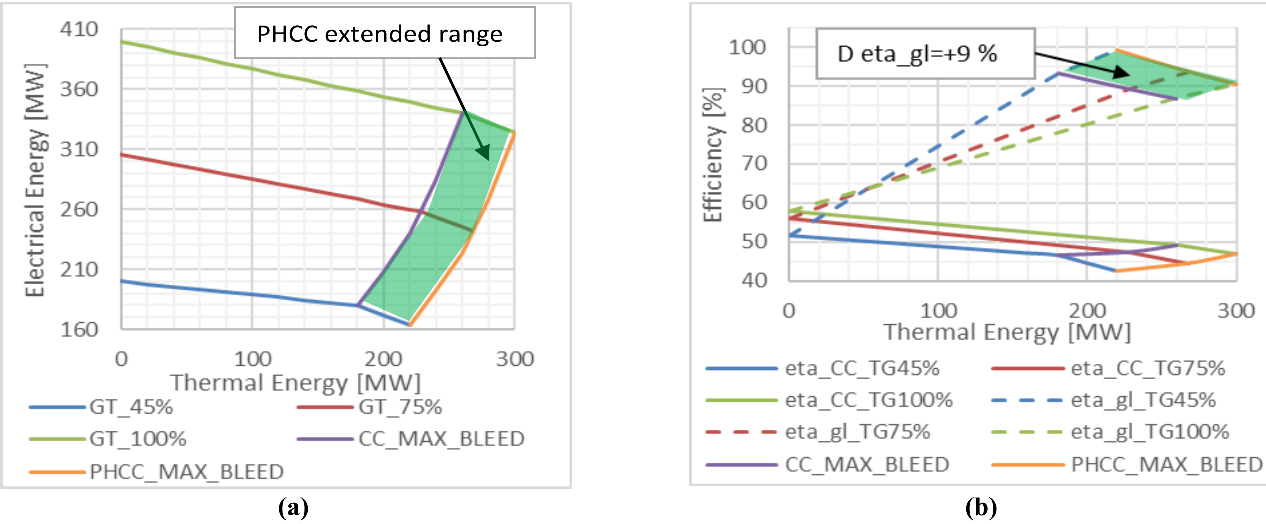


Fig. 8: Integrated system for CHP application (COP = 2.5): (a)Operational range, (b) Operational performance

- Increase the part load efficiency thanks to the inlet heating
- Act as a balancing Electrical Load,

Since the performance of such system depend also on the meteorological data, beside market constraint, the effect over the yearly efficiency will be presented in future works.

CHP Combined Cycle

As concerns the cogeneration plant layout instead (Fig. 5(2)), the main application to benefit the most from this integrated system is associated with a DHN, coupled with a warm temperature heat pump and a warm TES.

In thermal plants the utilization of a TES has grown given the frequent mismatch between the national electricity price and local DHN heat demand. Moreover, thermal energy storages, instead of electrical energy storages, have gained increasing attention due to the ability to store lower grade energy at competitive costs (Nuytten et al. ,2013; Smith et al. ,2013).

In this solution the TES would be charged, with the heat pump on, during low price periods, allowing to reduce electrical production still satisfying the heat demand and then discharged during thermal demand peaks. TES is considered an enabling technology to perform electricity arbitrage which represents one of the promising markets for this kind of application.

As first step just the integration of the CC with the HP was considered, and in particular the effect over the operative range and the effect over production global efficiency.

Considering a conservative COP of 2.5 for a 40 MWth heat pump, it is possible to observe from Fig. 8 how this solution extends the CCs operative range, increasing also the global efficiency.

Figure 8 refers to a real CHP CC at different GT loads (100%, 75%, 45 %) and with the increase of the steam bled to the DHN system: MAX_BLEED curves represent the full extraction conditions, when the thermal energy is maximized. In such condition the Z Factor, which represents the useful heat gained in MWh for electricity lost in MWh, was reported to be of around 4.7 for this kind of installation.

MARKET OPPORTUNITIES

A first analysis has been conducted to evaluate the number of hours per year during which it would have been profitable to use the layout proposed in the previous section, compared to a standard CHP CC plant layout.

As already highlighted in the “Italian energy market

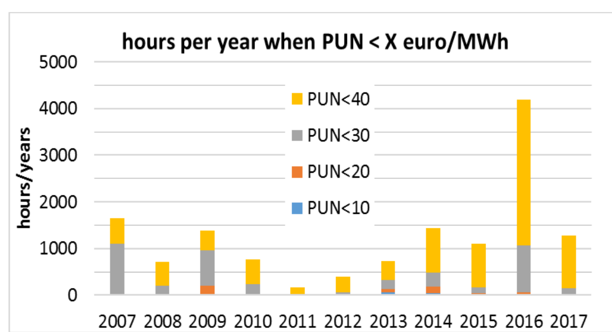


Fig. 9: Number of hours per year when PUN < X euro/MWh

overview” section, the PUN is globally reducing; with a slight change of trend in 2017

To evaluate the profitability of the heat pump integrated system with CHP CCs and to assess the number of hours per year during which would be fruitful to turn the HP on to produce thermal energy, the ratio between the PUN and the heat pump COP has been considered.

Three different heat pumps have been considered:

- HP1: installed in parallel with the DHN return pipeline (Fig. 10), delivering thermal energy at the DHN temperature level, working with a fraction of the DHN mass
- HP2 and HP3: in series with the DHN return pipeline (Fig. 10), working with higher mass flows these pumps require more complex pipeline connections and bigger heat exchangers. These pumps require the introduction of CC energy, via dedicated Heat Exchanger, to reach DHN temperature level.

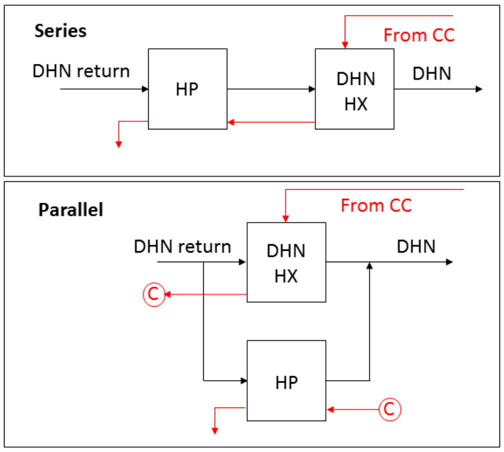


Fig. 10: Heat Pump Integration with CC and DHN - Schematic Layout

As preliminary calculation, the heat pumps have been considered to have the same thermal power of 10 MWth.

Tab. 4: Heat Pumps data for market analysis

	HP1	HP2	HP3
DHN Temp. [°C]	120	120	120
DHN return Temp. [°C]	70	70	70
HP delivery Temp. [°C]	120	95	80
HP Condenser Temp. [°C]	125	100	85
HP Evaporator Temp. [°C]	60	60	60
COP	4.00	5.48	6.41
HP thermal energy [MWth]	10	10	10
CC thermal energy [MWth]	0	10	40
CC share [0-1]	0	1/2	4/5
Critical PUN [€/MWh]	39.3	53.9	63.1

The DHN temperature of 120 °C has been set according to the one of the IREN Power Plant in Turin, which will be analyzed in the following, which correspond to the second generation of district heating systems.

CC share indicates the share of thermal energy between the heat pump and the combined cycle and is calculated as the energy provided by the CC over the total amount of energy delivered to the DHN. This value needs to be considered to evaluate correctly the costs of producing thermal energy with the heat pump (eq.3) and so the savings (eq.4).

The COP has been calculated as a function of the evaporator and condenser temperatures, evaluated after a private consultation with Mayekawa Europe (G. De Greve), which optimized the cycle; considering butane (R600) as working fluid and a thermal source internal to the CC cycle.

Heat pump costs have been evaluated as function of:

- HP thermal power, equal for all the cases
- Electric Motor, which size is related to the COP
- Piping, depending on the DHN mass flow rate elaborated by the condenser.

Tab. 5: Component specific cost

Equipment	specific cost
Electric Motor [k€/MWe]	64
Heat Pump [k€/MWth]	166
Piping [k€/MWth]	170

Equipment costs have been derived by Smallbone et al. ,2017 in good agreement with Mathiesen et al. ,2011 and Danish Energy Agency ,2018.

Tab. 6: Heat Pump Costs

Equipment	HP1	HP2	HP3
Electric Motor [k€]	160	117	100
Heat Pump [k€]	1660	1660	1660
Piping [k€]	680	1360	2040
Total Cost [k€]	2500	3137	3800

To evaluate the number of hours during which it would be profitable to produce thermal energy with the heat pump, compared to producing it with the combined cycle itself, the yearly PUN has been divided into fractions of 5 €/MWh and so the number of hours during which these fractions have occurred have been calculated (i.e. in 2016 the PUN in Italy has been between 25 €/MWh and 20 €/MWh for 233 hours).

The cost of producing thermal energy with the heat pump integrated system (reported in Tab. 7), considering the heat pump and the share of thermal energy with the combined cycle (CC_{sh}) required to reach DHN temperature level, has been calculated as:

$$C_{th_{j,k}} = \frac{PUN_j}{COP_k} * (1 - CC_{sh,k}) + \frac{COE}{Z_{factor}} * CC_{sh,k} \qquad (2)$$

Where $LCOE/Z_{factor}$ is the cost of producing thermal energy with the combined cycle. The subscript j refers to the PUN fraction considered (lines in Tab. 7 - 8) and the subscript k is related to the heat pump evaluated (HP1, HP2 or HP3). PUN/COP represents the cost of energy production with the HP at electricity market price.

Basing on that is it possible to define a critical PUN which represents an operative threshold for the profitability of the HP thermal energy compared with the CC one, and it has been evaluated as:

$$PUN_{critical} = \frac{COE}{Z_{factor}} COP \qquad (3)$$

A first order analysis of the savings which this integrated system would ensure has been made, considering as reference years 2016 and 2017, which present a completely different trend.

Tab. 7: Heat Pump integrated system thermal energy production costs evaluation – 2016 (COE/Z$_{factor}$ = 9.83 €/MWh)

Frequency 2016 [hours]	PUN [€/MWh]	HP1 C_{th} [€/MWh]	HP2 C_{th} [€/MWh]	HP3 C_{th} [€/MWh]
8	12.5	3.13	6.06	8.25
46	17.5	4.38	6.51	8.41
233	22.5	5.63	6.97	8.57
772	27.5	6.88	7.42	8.72
1527	32.5	8.13	7.88	8.88
1667	37.5	9.38	8.34	9.03
1422	42.5	10.63	8.79	9.19
1079	47.5	11.88	9.25	9.34
705	52.5	13.13	9.71	9.50
444	57.5	14.38	10.16	9.66
302	62.5	15.63	10.62	9.81
225	67.5	16.88	11.07	9.97
130	72.5	18.13	11.53	10.12
80	77.5	19.38	11.99	10.28

Tab. 8: Heat Pump integrated system thermal energy production costs evaluation – 2017 (COE/Z$_{factor}$ = 10.87 €/MWh)

Frequency 2017 [hours]	PUN [€/MWh]	HP1 C_{th} [€/MWh]	HP2 C_{th} [€/MWh]	HP3 C_{th} [€/MWh]
5	12.5	3.13	6.58	9.09
14	17.5	4.38	7.03	9.24
22	22.5	5.63	7.49	9.40
109	27.5	6.88	7.95	9.56
315	32.5	8.13	8.40	9.71
833	37.5	9.38	8.86	9.87
1190	42.5	10.63	9.31	10.02
1660	47.5	11.88	9.77	10.18
1585	52.5	13.13	10.23	10.33
893	57.5	14.38	10.68	10.49
561	62.5	15.63	11.14	10.65
389	67.5	16.88	11.59	10.80
337	72.5	18.13	12.05	10.96
219	77.5	19.38	12.51	11.11

The cells corresponding to the condition $C_{th_{j,k}} <$ COE/Z$_{factor}$ (or PUN < PUN$_{critical}$) have been highlighted.

The savings have then been calculated as:

$$Save_k = \sum_{j=1}^{n} \left(\frac{COE}{Z_{factor}} - \frac{PUN_j}{COP_k} \right) * H_j * P_{th,HP} \qquad (4)$$

Considering the difference between the cost of producing thermal energy with the combined cycle (COE/Z$_{factor}$) and the cost of producing the same amount of thermal energy with the heat pump (PUN/COP). The number of hours during which this condition has occurred have been indicated with H_j, while the heat pump thermal power ($P_{th,HP}$) has been assumed to be of 10 MW, hence it has been considered to work always at maximum power.

The computed savings for the two years considered and the relative payback periods (PBP) are reported in the following table; the cases for which the payback period would have been more than the plant useful lifespan (20 years) have not been specified.

Tab. 9: Savings and payback period for heat pump integrated system

	HP1	**HP2**	**HP3**
Savings 2016 [k€]	69.267	207.259	287.969
PBP 2016 [years]	>20	15.1	13.2
Savings 2017 [k€]	28.212	153.888	246.119
PBP 2017 [years]	>20	>20	15.4

From this first analysis is noticeable that the market actual condition is not suitable for this kind of integrated system, if they are used only to substitute combined cycle thermal energy production during low price periods.

The second scenario analyzed considered the savings which would be achieved by using the heat pump to produce a fraction of the thermal energy which would be produced by the heat only boiler, HOB. HOBs are usually installed within DHN as back-up unit and to produce heat during the morning heat demand peak.

For this analysis the same heat pumps enlisted in **Error! Reference source not found.** have been evaluated, considering a real case scenario provided by IREN and the number of hours during which the boilers have been turned on during 2016 in Turin Power Plant Complex.

In this case the savings have been computed considering the cost of producing thermal energy with the boiler instead of the combined cycle itself.

This cost, for the reference year of 2016 (25.77 €/MWh), has been calculated as the sum of three contributions:

- The ratio between the Gas Cost (Tab. 3) and the boiler efficiency (85%))
- Maintenance costs: 10% of the Gas Cost
- CO_2 Cost in €/MWh.

Tab. 10: Savings and payback period for heat pump integrated system – HOB energy replacement

	HP1	**HP2**	**HP3**
Savings [k€/year]	129.472	163.268	176.549
PBP [years]	19.3	19.21	>20

Considering only the HOB substitution scenario, all the HP present saving which are proportional to their installation cost leading to a PBP around the HP lifespan (HP3 has PBP of 21.5 years), so even this solution alone is not meaningful.

However, to evaluate the effect that this integrated system would have on the real power plant it is essential to consider both the scenarios previously analyzed and the possibility of an overlap. IREN CHP-CC power plant complex has been used as reference and its working conditions during 2016.

To compute the savings eq.4 has been used, considering coherently 2016 costs (HOB thermal energy cost 25.77 €/MWh and CC thermal energy cost 9.83 €/MWh).

Tab. 11: Savings and payback period for heat pump integrated system - CC+boiler

	HP1	HP2	HP3
Savings [k€/year]	179.607	313.853	385.284
PBP [years]	13.81	9.99	9.86

As expected the savings computed with this analysis are not the exact sum of the savings obtained from the previous scenarios analyzed, that is because in some conditions there has been an overlap of the condition in which the combined cycle and the boiler operate during 2016.

The payback period calculated in the latter analysis can be considered acceptable, particularly for HP2 and HP3 being less than 10 years (half of CC useful lifespan). However, it needs to be considered that these heat pumps would require a thermal energy share with the combined cycle, leading to a direct dependence on it, and the heat pumps need to work with huge mass flows being in series with the DHN return pipeline, already highlighted by the higher capital cost. Instead HP1 would be able to work without the working combined cycle and with lower mass flows, leading to lower capital costs and minor piping complexity.

FUTURE MARKET OVERVIEW AND OPPORTUNITIES

To analyze a probable future market scenario it has been considered a shift of the PUN, in respect to 2016, of 5 €/MWh (both positive and negative) and the IREN CHP-CC Power Plant as in the latter scenario of the previous section: In particular two main sub-scenarios have been analyzed (Fig. 11):

- Low PUN scenario: shift of 2016 PUN of -5 €/MWh
- High PUN scenario: shift of 2016 PUN of +5 €/MWh

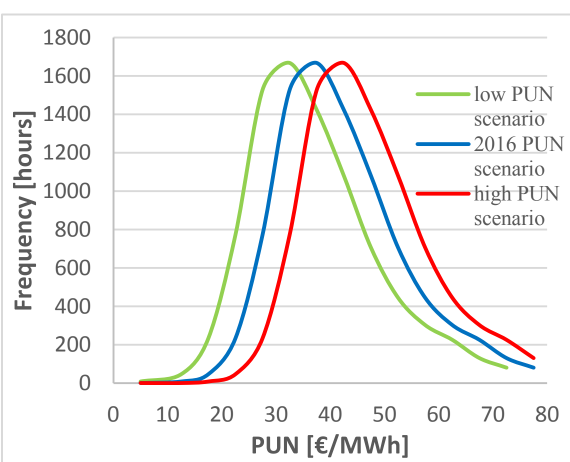


Fig. 11: Low PUN and High PUN scenario

Italian Energy Service Manager believes that in the following years there will be an increase of the CO_2 price which would lead, depending on the scenario considered, to prices between 14 and 24 €/tonCO_2 in 2025 and between 18 and 28 €/tonCO_2 by 2030 (Gestore dei Servizi Energetici ,2017).

However, in the two scenarios aforementioned the gas and the CO_2 costs, as the COE, have been considered the same of 2016. This kind of hypothesis can be made only if the PUN shift is independent from the gas cost (as it could occur in a market with higher renewables share).

Tab. 12: Savings and pbp for heat pump integrated system – Low and High PUN scenarios

		HP1	HP2	HP3
Low PUN scenario	*Savings [k€/year]*	228.894	371.325	438.483
	PBP [years]	10.92	8.45	8.66
High PUN scenario	*Savings [k€/year]*	130.319	256.380	332.086
	PBP [years]	19.18	12.24	11.44

As concerns the low-price scenario the impacts of this PUN shift on the savings and so on the payback period is remarkable, particularly HP2 would benefit of a greater increase of the working hours at a lower PUN, having an intermediate cost of thermal energy production (eq. 3) compared to HP1 and HP2, due to a small share with the combined cycle and the boiler, but a higher COP than HP1, guaranteeing better savings (eq. 4). Instead the high PUN scenario would not be favorable to this innovative plant layout, leading to high payback periods as expected.

CONCLUSION

This paper presented the situation of the Italian Combined Cycles, under an economic sustainability point of view. Efficiency, gas and CO_2 cost and Operating hours trend were considered to evaluate the COE for an "Italian average" 400 MW Combined Cycle, making differences between Power Oriented and CHP applications. For the same years the Electricity price trend considered, highlighting a long period reduction of price (2008-2016 period).

Then a market analysis of an innovative CC layout has been assessed, featuring a heat pump acting as smart load and a TES to increase cycle flexibility for both Power Oriented and CHP power plant. As first step the integration of just HP and a CHP CC feeding a DHN has been performed. The savings in the heat production, related to low price periods, were evaluated with respect to CC and HOB production costs. Focusing on this scenario, three different heat pumps have been considered, with the same thermal power but different temperature level, layout adopted and thermodynamic performance. In fact, to reach the DHN temperature level (120°C for the case study analyzed), different levels of integration with the CC are required. Three scenarios have been analyzed:

a) HP energy is used to substitute part of the thermal energy produced by the combined cycle using 2016 and 2017 energy prices.
b) HP energy is used to substitute part of HOB energy during heat demand peak, based on IREN data of 2016.
c) A combination of the two previous strategy on the 2016 operating condition and considering:
   - 2016 Electricity cost
   - 5 €/MWh shift sensitivity for a low and high energy price scenario.

The results obtained with this simplified analysis highlighted that, despite the higher capital costs, the heat pump with the lower temperature difference between condenser and evaporator presented a lower payback period thanks to a higher COP.

The savings computed in the scenario c) were greater than the previous scenario and with a payback period of about half of the power plant useful lifespan.

Considering a probable future market scenario, it has been made a further analysis of the IREN CHP-CC power plant complex in a low and high-price scenario. As concerns the low-price scenario the impact of this PUN change on the savings and so on the payback period of such a solution was remarkable on all the heat pumps, particularly on the one which presented an intermediate COP due to a greater increase of the number of working hours at lower PUN, while the high-price scenario led to high payback periods.

Actual market conditions are still not completely favorable to this kind of innovative plant layout (CHP HP + CC) leading however to interesting economic results, exploiting low electricity prices.

A further analysis featuring a thermal energy storage integration with the heat pump is under development within the PUMP-HEAT project. The whole integrate solution enables:

- to exploit the electricity arbitrage, exploiting the electricity price differences and exploiting the TES as an equivalent electrical storage;
- to run the HP when the CC is off, increasing the operating hours.

The CC and HP integration, shifting the heat production to the most convenient source can be envisaged as key-technology to reducing both generation cost and fuel consumption.

ACKNOWLEDGMENTS

This project has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No 764706

REFERENCES

ARERA, 2016. *Relazione 24 Giugno 2016 339/2016/I/efr*. https://www.arera.it/allegati/docs/16/339-16.pdf.

Benato, A., S. Bracco, A. Stoppato, and A. Mirandola. 2016. “Dynamic Simulation of Combined Cycle Power Plant Cycling in the Electricity Market.” *Energy Conversion and Management* 107: 76–85.

Danish Energy Agency. 2018. *Technology Data for Energy Plants for Electricity and District Heating Generation*.

Departement of Energy & Climate Change. 2015. *DIGEST OF UNITED KINGDOM ENERGY STATISTICS*.

Ecofys. 2014. *International Comparison of Fossil Power Efficiency and CO_2 Intensity*.

EEA - European Environment Agency. 2017. *Renewable Energy in Europe 2017 Updates*. https://www.eea.europa.eu/publications/renewable-energy-in-europe/file.

European Commission. 2011. Commission Staff Working Paper *Energy Roadmap 2050 Impact Assessment Part 1 Including Part I of Annex 1 “Scenarios - Assumptions and Results” [SEC(2011)1565/1]*. http://www.ncbi.nlm.nih.gov/pubmed/19097363.

European Commission. 2016. EU Reference Scenario 2016 – Energy, transport and GHG emissions - Trends to 2050

ISPRA 2016. National Standard Parameter http://www.minambiente.it/sites/default/files/archivio/allegati/emission_trading/tabella_coefficienti_standard_nazionali_2013_2015_v2.pdf

Ferrari M.L., Cuneo A., Pascenti M., Traverso A., Real-time state of charge estimation in thermal storage vessels applied to a smart polygeneration grid. Applied Energy, 206 (2017) 90-100

General Electric, August 2016, The world’s first battery storage and gas turbine hybrid

Gestore dei Servizi Energetici. 2017. *EU ETS: Rapporto Sulle Aste Di Quote Europee Di Emissione*. https://www.gse.it/documenti_site/Documenti GSE/Rapporti ASTE CO2/RAPPORTO_GSE_ASTE_II_TRIM_2017.PDF.

Gestore Mercati Energetici. 2018. “Dati Storici Mercati Gas.” http://www.mercatoelettrico.org/It/download/DatiStoriciGas.aspx (March 23, 2018).

De Greve, Günther. 2018. “MAYEKAWA Europe Nv.” http://www.mayekawa.eu/en/.

Mathiesen, Brian Vad, Morten Boje Blarke, Kenneth Hansen, and David Connolly. 2011. *The Role of Large scale Heat Pumps for Short Term Integration* *of Renewable Energy*. http://vbn.aau.dk/files/58142269/The_role_of_large_scale_heat_pumps_for_integrating_renewable_energy_20111124.pdf.

Mahmood M., Traverso A., Traverso A.N., Massardo A.F., Marsano D., Cravero C., Thermal energy storage for CSP hybrid gas turbine systems: Dynamic modelling and experimental validation. Applied Energy, 212 (2018) 1240-1251.

Nuytten, Thomas et al. 2013. "Flexibility of a Combined Heat and Power System with Thermal Energy Storage for District Heating." *Applied Energy* 104: 583–91.

Ricerca sul Sistema Energetico – RSE SpA, 2016. Energia Elettrica, Anatomia dei Costi ISBN 978-88-907527-7-3

Rivarolo M. , Cuneo A., Traverso A., Massardo A.F., Design optimisation of smart poly-generation energy districts through a model based approach. Applied Thermal Engineering, 99 (2016) 291-301

Rossi I., Sorce A., Traverso A., Gas turbine combined cycle start-up and stress evaluation: A simplified dynamic approach, Applied Energy, 190 (2017) 880–890.

Siemens. 2016. *Enhancing Gas Turbine Power Generation with Battery Storage*.

Smallbone, Andrew, Verena Jülch, Robin Wardle, and Anthony Paul Roskilly. 2017. "Levelised Cost of Storage for Pumped Heat Energy Storage in Comparison with Other Energy Storage Technologies." *Energy Conversion and Management* 152: 221–28.

Smith, Amanda D., Pedro J. Mago, and Nelson Fumo. 2013. "Benefits of Thermal Energy Storage Option Combined with CHP System for Different Commercial Building Types." *Sustainable Energy Technologies and Assessments* 1(1): 3–12.

TERNA. 2016. *Dati Statistici Sull'energia Elettrica in Italia*. http://www.terna.it/it-it/sistemaelettrico/statisticheeprevisioni/datistatistici.aspx.