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Design of a polygeneration system with optimal management for a district heating and cooling network

Paolo Lazzeroni[a,*], Sergio Olivero[a], Maurizio Repetto[b], Federico Stirano[a] and Vittorio Verda[b]

[a] *Fondazione LINKS, Via Pier Carlo Boggio 61, 10138 Torino, Italy*
[b] *Dipartimento Energia "G. Ferraris", Politecnico di Torino, Corso Duca degli Abruzzi 24, 10124 Torino, Italy*

ABSTRACT

Nowadays, District Heating and Cooling (DHC) networks represent a viable and efficient way to distribute energy for space heating and cooling in urban areas with high density demand. This is particularly true in a context characterized by higher fuel price and restrictive regulatory framework. DHC systems give the possibility to integrate energy sources available in the territory and supply thermal energy to a conveniently large number of end-users; these are thus potentially capable to cover the demand at lower costs, higher efficiency and reduced emissions compared to not centralized systems. In the European Union, the Energy Efficiency Directive 2012/27/EU promotes these systems to increase the use of Renewable Energy Source (RES) and the efficiency, by introducing the definition of 'efficient DHC': at least 50% of renewable energy, 50% of waste heat, 75% of cogenerated heat or 50% of a combination of such energy and heat should be used. Polygeneration systems, as hybrid energy systems combining RES and traditional generation units, are then crucial to supply DHC networks in a sustainable way for reducing fossil fuel dependencies and emissions.

In this context, this paper presents the design assessment of the generation facilities for an existing DHC network located in the northern part of Italy. The design stage considers traditional fossil fuel units like boiler and Combined Heat and Power (CHP), but also renewable ones like solar thermal, absorption/electric chiller and other low enthalpy sources as options of the case study. The sizes of the generation units are defined according to the heating/cooling demand of the buildings supplied by the DHC, the estimated network losses and the present regulatory framework. The plant management is identified through an optimization procedure capable to minimize the operational costs according to the technical characteristics and constraints of the plant. Four different configurations with increasing costs saving, installation costs, Renewable Energy Sources (RES) generation and Primary Energy Saving (PES) are presented. A preliminary economic analysis is also presented for the various configurations considering the Italian incentive schemes. Finally, an energy assessment is presented to highlight the share of the different sources in each configuration and to evaluate their compliance to the EU Directive on efficient DHC.

The results reveal how the integration of RES within polygeneration systems can be sustainable from the energy and economic point of view thanks to the Italian supporting scheme and the optimal management of the resources.

Keywords:

Design polygeneration system;
Efficient DHC network;
Optimal management;

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1. Introduction

The District Heating and Cooling (DHC) networks are recognized as efficient systems capable to distribute energy for covering space heating/cooling and Domestic Hot Water (DHW) demand [1, 2]. This is particularly true in the Northern part of Italy where DH networks are widely diffused within cities to supply heat demand to buildings in area with high density demand [3]. On the

*Corresponding author - e-mail: paolo.lazzeroni@linksfoundation.com

contrary, DC network are not still largely adopted [4], but the increasing energy demand of space cooling in buildings demonstrates how Italy have a great potential for the development of DC due to the severe weather condition experienced in summer. Nevertheless, the heat generation within DH and DHC network is usually based on fossil fuel [5] also in the Italian context. Thus, the introduction of Renewable Energy Sources (RES) in DHC represents a prospective for more sustainable multi-energy systems with a consequent increase of the Primary Energy Saving (PES) and a reduction of the operational costs and greenhouse gases emissions [6].

Similarly, energy harvesting solutions recovering heat at different temperature can also be potentially investigated to reduce energy losses, increase PES and the overall efficiency of the systems to move DH toward 4th generation [7]. In this light, the EU commission has recently released the Directive to encourage efficient DHC networks [8] aiming at increase the diffusion of cogeneration and trigeneration systems integrated with RES within hybrid system.

However, the design of hybrid energy system is complex to be identified from the economic point of view. In fact, installation costs of RES are typically expensive than conventional sources based on fossil fuel, but RES integration ensures reduced operational costs [9]. Moreover, hybrid polygeneration systems are complex since typically different energy vectors are involved at once, RES generation is intermittent and thermal storage unit must be properly managed for maximizing the RES exploitation and reduce operational costs [10]. For these reasons, the contribution of the different sources supplying the costumers demand, need to be optimally scheduled to minimize the operational costs of polygeneration plants and to increase the economic feasibility of RES integration [9, 11].

A wide literature is focused on this particular aspect [12, 13]. For example, the possible installation of RES production in an existing polygeneration system is discussed in [14] through the optimal scheduling of the sources: the integration of renewables reduces operational costs and emissions but it increases investment costs compared to solutions based on fossil fuel. An energy scheduling model is instead defined in [15] to evaluate economic feasibility for the energy transition of urban districts towards 100% of renewables. Similarly, the integration of Photovoltaic (PV) production is also evaluated at urban level in [16] through an heuristic optimization approach for reducing CO_2 emissions and increase decarbonisation.

Under this general context and according to the existing literature, this paper intends to show the design stages of a case study of a polygeneration system supplying an existing DHC network in North of Italy through an optimization tool. Different possible configurations of a multi-energy system with increasing complexity and RES integration are proposed and studied by means of an optimization tool named XEMS13 [17] capable to minimize the operational costs considering technical constraints, energy prices and the regulatory framework. The economic optimization presented in this paper is based on a Mixed Integer Linear Programming (MILP) formulation of the problem as described in [18]. Energy harvesting solutions are also taken into account as additional opportunity to increase the efficiency of the overall system, reducing emissions and operational costs. [19]

Finally, an evaluation of the investments planned for each configuration and a comparative analysis of the proposed solutions from economic and energy point of view are presented and discussed to evaluate the sustainability of RES integration within a polygeneration system.

2. Case study

The case study presented in this paper refers to an existing DHC network located in the North-West of Italy. The network is presently used to supply an area where different building typologies are connected to cover space heating/cooling and domestic hot water (DHW) energy demands.

Table 1 summarizes the yearly energy demands for the buildings connected to the DHC network as measured by the energy manager in 2016. It is noticeable that tertiary buildings are the larger energy consumers in the area, since they account for 78% and 70% of the whole demand for space heating/DHW and space cooling, respectively.

The DH network is operated with a supply temperature of 80°C and a return temperature of 65°C, while supply and return temperatures for the DC network are 5°C and 12°C, respectively. Notwithstanding, the unusual high return temperature could be potentially reduced to increase the performance of the DH network (e.g. reduction of heat losses). However, the above mentioned

Table 1: Yearly energy demands of the buildings connected to the DHC network

Building Id	Building Typology	Yearly consumption for space heating and DHW (MWh)	Yearly consumption for space cooling (MWh)
A1	Residential	111.75	29.80
A2	Residential	108.98	31.37
C1	Commercial	110.53	35.12
C2	Commercial	366.71	211.03
E	Tertiary	630.98	370.22
V	Tertiary	1761.00	239.10
M	Commercial	119.94	45.82
W	Tertiary	128.93	91.91
Z	Tertiary	553.90	170.70
Q	Residential	48.21	21.68

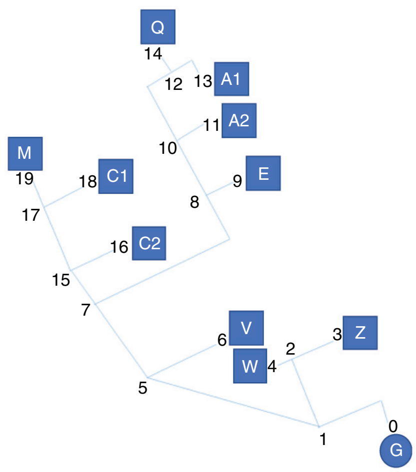

Figure 1: layout of the DHC network for the case study

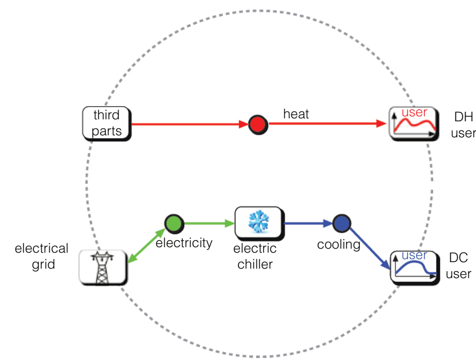

Figure 2: Present configuration of the generation units

supply and return temperatures were assumed as fixed in the analysis described later. This constraint is due to a pre-existing contractual agreement between the manager of the DHC network and the customers and it cannot be presently modified.

Figure 1 shows a simplified layout of the DHC network suppling the buildings presented in Table 1, where G is the proposed location for the installation of the polygeneration systems.

2.1. Present configuration

The space cooling energy demand of the buildings currently connected to the DHC network area is met by the production of chilled water locally supplied through a generation plant consisting of two compression chillers equipped with the following characteristics:

- a unit with 1750 kW of cooling capacity and a seasonal COP of approximatively 4.5
- a unit with 550 kW of cooling capacity and a seasonal COP of approximatively 4.5

These electric chillers are supplied by a Medium Voltage (MV) grid connection also used to provide electricity to the pumping systems for moving the hot and the chilled water in DHC network as well as in the cooling towers.

On the contrary, the hot water is not produced locally, but it is purchased through a supply contract from third party. In this case, the generation plant of hot water is only represented by a pumping system capable to pressurise and move the hot water in the DH network. Figure 2 summarizes the present layout of the generation plant considered in this case study.

The DHC network of Figure 1 is presently formed by pre-insulated double pipes that connect the generation plant with the different users. A simplified mathematical

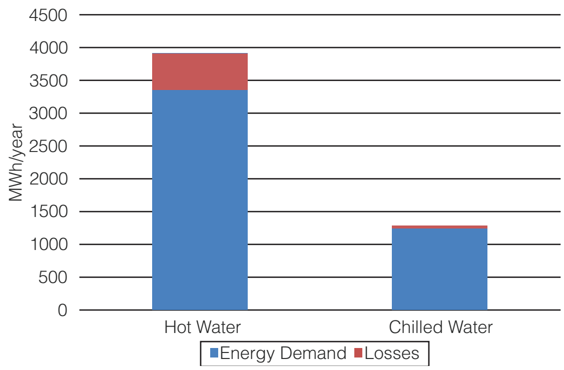

Figure 3: Yearly energy demand and losses of the DHC network

modeling was defined for calculating the thermodynamic quantities that describe performance of the system (i.e. yearly heat losses).

The calculation of the heat losses in the DHC was performed by a simplified evaluation of the water flow rate and the temperature drops in each pipe. This assessment was carried out considering two different operating conditions during a day:

a) A stationary condition when the set-point temperatures of the DHC networks are reached
b) A transient condition when temperatures decrease/increase by shutting down/up the plants.

The first condition (a), is substantially reached in the late morning and maintained approximatively for 8 hours until the plants shut down. In this case, the water flow rate in the pipes is based on the network topology and on the calculation of an average daily power consumption, which is derived from the energy consumption of Table 1. For this stationary condition, the temperature drop of a pipe and consequently the heat losses are approximated through a inversely proportional function of the water flow rate (i.e. obtained as a first order Taylor's series approximation of the exponential function [20] for the evaluation of the temperature drop of a pipe in stationary condition).

The second condition (b) is instead approximatively maintained for 16 hours. In this case the evolution of the temperature in the network is calculated considering the water flow rate close to zero. As a consequence the temperature drop in pipe is calculated as ones for a storage tank through exponential function (i.e. as obtained from the solution of the differential form of the Fourier's law).

The evaluation of the heat losses through the heating and cooling seasons, estimates the overall efficiency of the DH and DC networks. In this condition, the yearly heat losses of the DH network are approximatively close to 20% of the demanded energy, while losses of DC network are around 5% of the supplied energy (see Figure 2). This difference is due to the gap between the water and ground temperature which is greater in the DH network compared to the DC one.

3. Optimal scheduling

The current configuration of the area presented in Figure 2 is particularly stressed from economic point of view. The increasing energy supply costs of the hot water provision for the DH network purchased by third party is forcing the energy manager of the area to an upgrade of the present configuration of the energy production plant, including the introduction of RES. A possible solution investigated in this paper is the upgrade of the existing configuration by locally installing a self-generation system to produce hot water. For this reason, a feasibility study with a technical and economic evaluation for implementing new possible poligeneration configurations was carried out.

The study was performed through an optimization tool named XEMS13. This tool developed by the Energy Department of the Politecnico di Torino and LINKS [11, 17, 18, 19] simulates polygeneration systems by means of an optimized management of the sources minimizing operational costs by considering technical and operational constraints.

According to the aforementioned characteristics of the optimization tool, the objective function of the proposed problem is represented by the operational costs of the poligeneration plant, calculated as follows:

$$OF = \sum_{i=1}^{N_i} \left(\sum_{g=1}^{N_g} C_g(t_i) P_g(t_i) + C_p(t_i) P_p(t_i) - C_s(t_i) P_s(t_i) \right) \Delta\tau \qquad (1)$$

In practice, the time horizon is discretized by subdividing the simulation in *Ni* intervals with equal length usually of one hour. In each time interval, the costs for generating energy by the different N_g sources and the cost for purchasing electricity from the grid are summed up and then they are subtracted by the gains obtained by selling electricity into the grid. The price C_g for producing each unit of energy P_g, the prices for purchasing (i.e. C_p) or selling (i.e. C_s) each unit of electricity (i.e. P_p and P_s respectively) can be time dependent or independent according to the type of sources and the supply contract for buying and selling electricity.

The workflow of the optimization tool is substantially subdivided in three steps according to the description presented in [11, 18]. Initially (step #1), the time profiles of the energy demand (i.e. heating, cooling, electricity), the time profiles of the energy prices (i.e. electricity, natural gas, etc.) and the time profile concerning the renewable generation (e.g. solar thermal) are acquired. Then (step #2), technical and operational characteristics of the different sources as well as the connections between them are fixed. Consequently, two different sets of equations (constraints) are identified:

- *Balance equations* representing the energy balance of each energy carriers in order to ensure feasible solution where demand is covered by production.
- *Constitutive equations* representing the relationship between the input and output power of a sources, as well as its operational limits.

Finally (step #3), the optimal scheduling for the different components of the plant is found by means of a solver for Mixed Integer Linear Programming (MILP) formulation. So, all the aforementioned equations describing the problem have to be linear. In case of non-linear functions and constraints, piecewise linear functions are used to approximate the system or components behaviour.

3.1. Hourly load profiles

As already observed, the time profiles of the energy demand for the whole area are needed to simulate the optimal management of the different energy sources in the upgraded configurations of the production plant. The heating and cooling demand of the area can be defined as the sum of the energy needs of the buildings and the heat losses of the DHC network.

The hourly load profiles of each building supplied by the DHC network were identified through daily normalized load profiles present in literature or derived from measurement in similar climatic zones [21, 22]. These normalised load profiles are grouped by building typology and period of the year. In fact, it is worth nothing that space heating and cooling demand change for different season and type of end-user. Then, under the hypothesis that all the days in a given season have the same profile, the normalized load profiles were opportunely re-scaled by means of a correction factor f_c, to ensure that the energy annually required by each building coincides with the measured data of Table 1.

In this way, the yearly energy E_y consumed by a building can be calculated as follows:

$$E_y = f_c \cdot \sum_{i=1}^{8760} P_{p.u.}(t_i)\Delta t \qquad (2)$$

where $P_{p.u.}$ is the value of the normalised load profile in a given time interval and Δt is the length of the time interval (i.e. one hour in this case). Later, the profiles of the energy demand for the whole area were obtained by summing up each building load profile and the heat losses of the DHC network, under the approximation that the load profile of network losses is flat.

The yearly aggregated load profiles for the heating and cooling demand were finally subdivided in 14 representative weekly profiles, since the heating season for the area starts at 15th October and stops at 15th April. Thus, 12 weeks were defined to represent each month of the year, but two additional weeks were used to consider the no-heating period in the first half of October and in the last half of April.

Figure 4 shows two of the representative weekly load profiles of the area. These weeks refer to the periods in which the peak of heating/DHW demand and the peak of cooling needs are reached. In particular, Figure 4a shows how the peak for space heating and DHW presently can

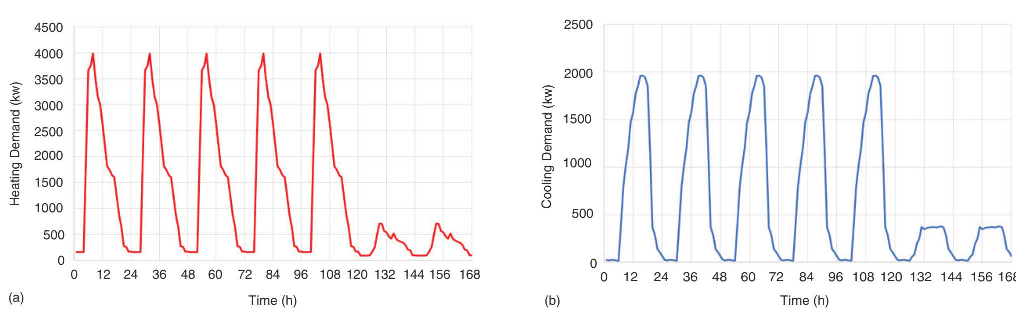

Figure 4: Aggregated weekly load profiles of the area for: a) space heating and DHW in January, b) space cooling in July

reach approximatively 4MW, while Figure 4b shows how the peak for space cooling can potentially reach 2MW. The latter condition evidences how the cooling demand is close to the maximum capacity of the present configuration. This situation shows potential bottleneck, which could be critical during adverse environmental conditions in summer.

The electric load profiles for the pumping systems of DHC network were instead derived from the heating and cooling one, assuming that electric profiles follow the thermal one and the electricity consumption of the pumping systems is equal to 3.5% of the corresponding thermal demand, as resulting from electricity bills.

3.2. Energy prices

As in the analysis for defining the load profiles of the different energy vectors, the assessment of the present energy prices was performed to individuate the unit price for each energy carriers of the area. The electricity currently purchased by the MV distribution grid for feeding the compression chillers and the pumping systems refers to a Time-of-Use (ToU) Italian tariff. The electricity prices presented in Table 2 include the variable access grid costs, variable general system costs and the excises. Other fixed costs are not considered since this quota does not change in the upgraded scenario when compared to the reference present scenario.

The hot water for suppling the buildings connected to the DH network is instead currently purchased by third parties at a price that can be considered approximatively close to 65 €/MWh. For this reason, the upgraded scenarios proposed in this paper were compared with this current value considering also other fixed costs to be paid to the third parties which account for around 33k€ per year.

Since in the proposed new scenario electricity generation systems could also be introduced, the prices for the electricity sold to the grid were also identified. These prices refer to the historical data provided by the Italian Energy Market Operator (GME) [23] for the year 2015. Figure 5 shows an example of these time profiles for some periods of the year.

Finally, the unit price of the natural gas for supplying the heat generation systems to be introduced in the upgraded scenarios was estimated at approximatively 0.37 €/Nm^3. This value, that does not include excises, is derived from the natural gas price database of the Italian Energy Authority (ARERA) [24]. The price used refers to an estimated demand of around 1Mm^3/year obtained for polygeneration plants with an installed capacity similar to the existing one. The natural gas price was later increased by adding the excises value which

Table 2: Electricity Time-Of-Use tariff of the case study

Day	On-peak	Mid-peak	Off-peak
Mon-Fri	8–19	7–8; 19–23	23–7
Sat	–	7–23	23–7
Sun	–	–	0–24
Price (€/MWh)	151	146	136

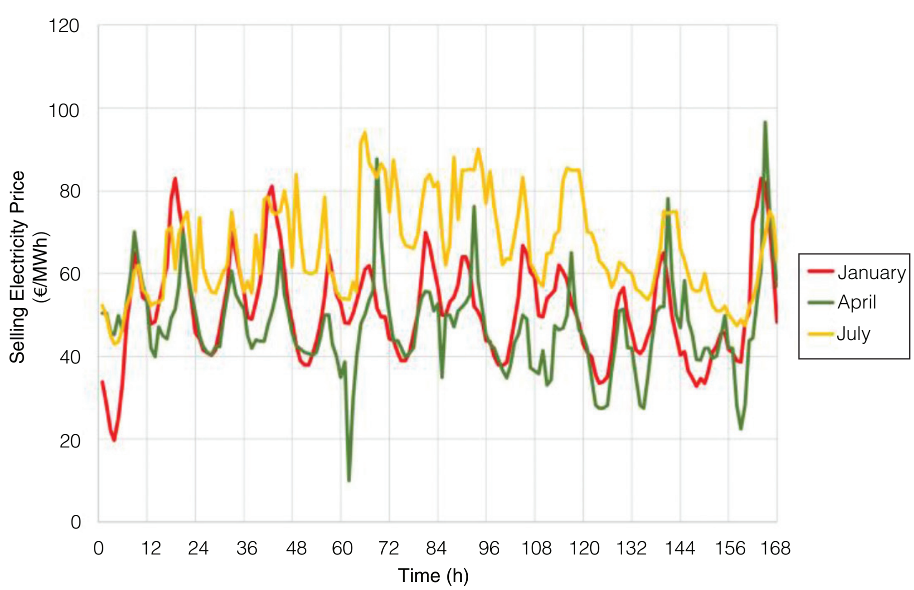

Figure 5: Trends of the Italian selling electricity price in different periods of the year

depend on how the use of natural gas is classified in each new configuration according to the definition introduced by ARERA.

4. Proposed configurations

As already described in Section 3, the current energy supply costs of the hot water provision purchased by third party are forcing to an upgrade of the present configuration (see Figure 2 in Section 2) of the energy production plant. In this section, four different new configurations are presented in Table 3 and Figure 6 for producing hot and cold water by systems with incremental complexity where also RES are involved. In the proposed configurations, all the generation facilities are located and connected in the same point of the network

Table 3: Installed power capacities for the different configurations

	Technical characteristics							
Unit	**Scenario 1**		**Scenario 2**		**Scenario 3**		**Scenario 4**	
Electric Chiller #1	P_n = 1750kW$_f$	COP = 4.5	P_n = 1750kW$_f$	COP = 4.5	P_n = 1750kW$_f$	COP = 4.5	P_n = 1750kW$_f$	COP = 4.5
Electric Chiller #2	P_n = 550kW$_f$	COP = 4.5	P_n = 550kW$_f$	COP = 4.5	P_n = 550kW$_f$	COP = 4.5	P_n = 550kW$_f$	COP = 4.5
Boilers	P_n = 6000kW	η = 0.92	P_n = 5000kW	η = 0.92	P_n = 5000kW	η = 0.92	P_n = 5000kW	η = 0.92
CHP	–	–	P_e = 635kW P_t = 766kW	η_e = 0.395 η_t = 0.476	P_e = 635kW P_t = 766kW	η_e = 0.395 η_t = 0.476	P_e = 635kW P_t = 766kW	η_e = 0.395 η_t = 0.476
Absorption Chiller	–	–	P_n = 500kW$_f$	COP = 0.7	P_n = 500kW$_f$	COP = 0.7	P_n = 500kW$_f$	COP = 0.7
Thermal Storage	–	–	E = 3.5MWh	V = 180m^3	E = 3.5MWh	V = 180m^3	E = 3.5MWh	V = 180m^3
Solar Thermal	–	–	–	–	P_n = 180kWp	S = 500m^2	P_n = 180kWp	S = 500m^2
Heat Pump	–	–	–	–	–	–	P_n = 390kW$_t$	COP = 2.5

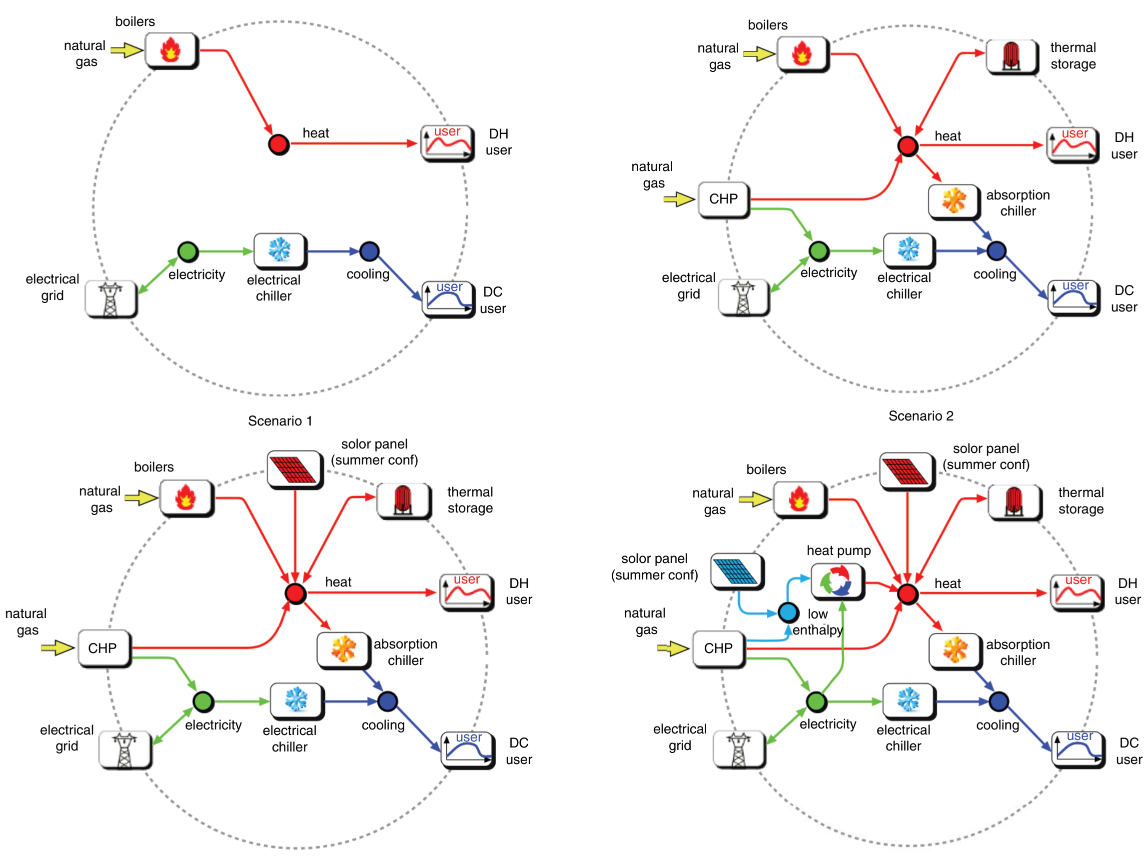

Figure 6: Proposed upgraded scenarios

(node G of Figure 1) due to the fact that the network is spread over a small area.

4.1. Scenario 1

In the first scenario presented in Figure 6, the production of hot water for feeding the DH is obtained by means of a boilers unit supplied by natural gas. The size selected for the boilers group was 6MW with an estimated efficiency of 92%, since the peak of the heat demand is approximatively close to 4MW as already shown in Figure 4a. In this scenario, the excises to be applied in addition to the cost for natural gas presented in Section 3 are equal to 0.2118 €/Nm^3 following the Italian regulations [25]. This is due to the classification introduced by the Italian Energy Authority which classify as "civil use" the natural gas used to supply the boilers in this configuration.

4.2. Scenario 2

Scenario 2 (see Figure 6) represents an evolution of the Scenario 1 where a cogeneration unit (CHP) is added together to an absorption unit for recovering heat produced by CHP and a thermal storage unit to increase the flexibility and the efficiency of the overall system.

The installation of a CHP unit benefits of reduced excises for the natural gas used to supply both boilers and the CHP, if the following conditions are met:

- The ratio between rated thermal power of CHP and total installed thermal power (CHP + boilers) must be ≥ 0.1
- The yearly electricity production of CHP must be ≥ 10% of the thermal energy produced by the polygeneration system.

In this case, the natural gas used to supply the poligeneration system is subjected to excises for "industrial use" equal to 0.018 €/Nm^3 [25]. However, part of the gas feeding the CHP, that is calculated as 22% of the electricity produced by the CHP, is subjected to reduced excises for "electricity production" equal to 0.0004433 €/Nm^3 [25].

Scenario 2 can benefit of a further incentive related to the qualification as High-Efficiency Cogeneration (CAR) unit [26]. The CAR qualification is achieved when cogeneration respects the following limits [27]:

- The global efficiency n_g of the CHP must be greater than or equal to 0.75 for CHP consisting of internal combustion engines fed by natural gas:

$$n_g = \frac{E+H}{F} \tag{3}$$

where E is the gross electricity yearly generated, H is the thermal energy yearly produced and F is the annual total energy of the natural gas used to fed the CHP.

- Primary Energy Saving (PES) must be positive for small cogeneration units (i.e. size ≤1MWe):

$$PES = \left(1 - \frac{1}{\frac{CHP\,H\eta}{Ref\,H\eta} + \frac{CHP\,E\eta}{Ref\,E\eta}} \right) 100 \tag{4}$$

where $CHP\ H\eta$ and $CHP\ E\eta$ are the annual thermal and electric efficiency of the CHP, while $Ref\ H\eta$ and $Ref\ E\eta$ are the reference value of the efficiency for separate production of heat and electricity [28].

The CAR qualification allows to obtain Energy Efficiency Certificates (*TEE* or white certificates) proportionally to the savings calculated as follows:

$$TEE = 0.086 \cdot K \cdot \left(\frac{E}{\eta_{e\,rif}} + \frac{H}{\eta_{t\,rif}} - F \right) \tag{5}$$

where K is a factor based on the CHP size, while $\eta_{t\ rif}$ and $\eta_{e\ rif}$ represent the average thermal efficiency of the Italian heat production systems and the average electric efficiency of the Italian electricity production systems, respectively. Presently the average value of each Energy Efficiency Certificate in the Italian market is close to 220€ [23], but a peak of more than 250€ was also recently reached. However, a more prudent value of 150€ is used here.

4.3. Scenario 3

Scenario 3 (see Figure 6) integrates RES production within the Scenario 2. In particular, heat production from solar thermal collectors was introduced to cover part of the heating demand of the DH network. For this reason, hot water production from solar collectors is supposed to be at the supply temperature of the network (i.e. 80°C), with a tilt angle of 50° and azimuth equal to 0° to ensure production also in mid-season. The total gross area of solar field was chosen so that the daily production meet approximately 50% of the daily heat losses of the DH network during the worst operating condition (i.e. summer period in July). This choice avoids large plant size of the solar field, unable to be feasibly realized.

A gross surface of the modules equal to around 500m^2 was calculated for generating the required energy by means of an analysis of the solar irradiation [11, 29] of the area considering the tilt angle, the azimuth angle and the supply temperature of the water. Moreover, the Scenario 3 benefits of an additional incentive for the installation of solar thermal collector according to the Italian scheme named "Conto Termico" [30]. The yearly incentive *I* is proportional to the annual energy production of a single module calculated as follows:

$$I = C_i \cdot Q_u \cdot S_l \tag{6}$$

where C_i is the coefficient to economically valorise the thermal energy produced Q_u and S_l is the gross area of the solar field.

4.4. Scenario 4

The last scenario (i.e. Scenario 4 as shown in Figure 6) improves the Scenario 3 where the high set-point (i.e. 80°C) of the supply temperature for the solar collector reduces the heat production during winter. The proposed solution is a reduction of the supply temperature, during the heating season (October 15th - April 15th), down to 55°C and then use a water-to-water heat pump to warm-up the water up to the DH supply temperature of 80°C. Instead, the solar collectors have a set-point of 80°C for the supply temperature outside the heating season. In this new configuration, low enthalpy heat (at 55°C) can be also recovered from the cooling system of the CHP, which otherwise should be wasted in the environment. This low enthalpy heat feeds the same water-to-water heat pump coupled by the solar collectors.

5. Results

The proposed scenarios were implemented in the XEMS13 optimization tool to evaluate the optimal scheduling of the difference sources in the four proposed configurations and the corresponding yearly operational costs, considering technical and operational constraints of each components of the polygeneration system. These results were compared to one obtained for the reference configuration of Figure 2 to highlight the corresponding costs savings as shown in Table 4.

Figure 7 shows an example of the XMES13 solutions concerning the scheduling of the hot water production for supplying the DH network in summer for Scenario 4. It is noticeable that the TES unit reduces CHP production (Ptle) by storing its daytime overproduction (PSttin) and realising it during night-time (PSttout). Moreover, the effect of the heat produced by the solar field (Psh) contributes to cover the heat demand (Ut) especially during daytime of the weekend.

Table 4: Economic results obtained for the different configurations

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CAPEX (k€)	600	1385	1560	1638
O&M (k€/y)	12	29.6	31.3	35.2
Costs savings (%/y)	3.63	34.9	35.9	36.1
PBT (years)	>20	9.5	9.85	11.2
NPV (k€)	–305.3	1830.9	1808.9	1827.7
IRR(%)	–6	10.7	9.8	9.6

Figure 7: Optimal scheduling of the different sources in the Scenario 4 by XEMS13

An economic analysis was also performed to calculate the economic indicators for evaluating the investment profitability of the different proposed scenarios. In particular, the Net Present Value (NPV), the Internal Rate of Return (IRR) and the Pay Back Time (PBT) were used to compare the different solutions. In particular, a discount rate of 4% was considered for the definition of the NPV, while a technical lifetime of 20 years was used for the evaluation of the IRR.

Investment and the yearly O&M costs for the technologies proposed in the different scenarios derive from [31]. The former were used to evaluate the installation cost of the proposed upgrade in each scenarios, while the latter were added to the operational costs estimated by XEMS13 for calculating the yearly cash flows in the NPV and IRR. O&M costs are generally considered as a percentage of the investment cost, but in some cases (e.g. CHP) this costs refer to the energy generated (i.e. expressed as €/kWh), so they are directly added in the objective function. Finally, Savings of operational costs were also evaluated considering the costs of the present configuration as reference.

Table 4 shows the results carried out by the economic analysis. In particular, Scenario 1 is economically unsustainable because of the impact of the excises on the natural gas used to feed the boilers, since this scenario is classified as "civil use", according to the ARERA classification. On the other hand, Scenario 2 is more economically attractive thanks to the introduction of a CHP system combined with the boilers unit, which greatly reduces the excises on the natural gas. In fact, the electricity produced in this Scenario represents 38.3% of the heat produced by the whole systems and the ratio between rated thermal power of CHP and total installed thermal power is equal to 0.15. Consequently, reduced excises are paid by Scenario 2 according to the condition presented in Section 4.2. Moreover, the whole system could be qualified as High-Efficiency Cogeneration unit (CAR), since PES and the global efficiency are equal to 23.9% and 87.1%, respectively. Thus, Energy Efficiency Certificates can also be obtained to further support the investment.

Scenario 3 introduces hot water production from solar thermal collectors starting from the configuration of Scenario 2. The investment cost for the installation of the solar field can be partially recovered thanks to the additional Italian incentive named "Conto Termico".

However, the economic indicators obtained for this configuration are slightly worse than ones of Scenario 2, due to the reduced heat production from the solar field during winter. Reduced excises, CAR qualification and Energy Efficiency Certificates can be also obtained for this configuration. In fact, the electricity produced in this Scenario is equal to 33.3% of the heat produced by the whole systems, the PES is equal to 23% and the global efficiency is equal to 87%.

Scenario 4 modifies the configuration of Scenario 3 by reducing the set-point of the supply temperature from 80°C to 55°C during the heating season (October 15th to April 15th). Furthermore, low-temperature water (i.e. at 55°C) is also recovered from the cooling system of the CHP in order to supply a water-to-water heat pump and to increase the overall efficiency of the plant. In this configuration, the economic indicators improve if compared to Scenario 3, thanks to the increase of both heat production of the solar field and plant efficiency. Again, reduced excises, CAR qualification and Energy Efficiency Certificates can be also obtained for this configuration. In fact, the electricity produced in this Scenario is equal to 35.9% of the heat produced by the whole systems, the PES is equal to 25.9% and the global efficiency is equal to 91.5%.

Scenario 2 and Scenario 4 could therefore represent the possible solutions to be adopted, taking into account that Scenario 4 could be reached at a later stage once Scenario 2 was previously completed.

Finally, Figure 8 shows the share of the different sources for covering of the load demand from end-users connected to the DHC network.

These values define if each different scenario can be considered as an "efficient district heating and cooling" configuration following the definition introduced by the European Directive [8]: 'efficient district heating and cooling' means a district heating or cooling system using at least 50% renewable energy, 50% waste heat, 75% cogenerated heat or 50% of a combination of such energy and heat. In this context, all the scenarios can be defined as efficient district cooling since the production of cold water comes from electric or absorption chillers. On the other hand, district heating can be defined as efficient only for the Scenario 4 where more than 50% of the demand is covered by a combination of heat produced by cogeneration and renewable sources.

6. Conclusion

The paper presents the design stage of a polygeneration systems for supplying an existing DHC network located

Figure 8: Yearly energy share in the different configurations as evaluated by XEMS13

in the northern part of Italy. In fact, the present reference scenario is subjected to an increasing energy supply costs of the hot water provision for the DH network purchased by third party. A feasibility study for an upgrade of the current configuration for generating the thermal energy was analysed presenting four different solutions with increased complexity. The first Scenario integrates a group of boilers to the existing cooling generation units. A CHP, an absorption chiller and a TES were also added in the second one, while heat generation by a solar field is then implemented in the third scenario. A water-to-water heat pump is finally included in the fourth scenario to better exploit the production of the solar collectors in winter and to harvest low temperature water from the cooling systems of the CHP. Costs and energy saving obtained by the different scenarios with respect to the existing situation were evaluated through an optimization tool to find the best scheduling of the sources for minimizing the operational costs. The optimal results were then used to evaluate the yearly cash flows obtained in each scenario and to perform an economic and energy analysis. These analysis show how the last scenario represent the best compromise between energy and economic point of view thanks to the combination of RES generation and energy harvesting which increase costs saving and PES but reduce the usage of fossil fuel. The analysis also show how the incentive scheme are still relevant to make economically sustainable the investments in RES and high efficiency solutions in the Italian context.

Finally, the use of optimization tool also remarks the needs for introducing RES and energy harvesting solutions capable to increase system efficiency and to be classified as ‘efficient DHC’ under the EU Directive.

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