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# Techno-Economic Analysis of a Hybrid Renewable Energy System (HRES) with Biogas-Powered Combined Heat and Power (CHP) and Photovoltaic (PV) Systems

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**Abstract.** The global shift toward sustainable energy underscores the urgency of reducing GreenHouse Gas (GHG) emissions and dependence on fossil fuels. Hybrid Renewable Energy Systems (HRES), integrating biogas-powered Combined Heat and Power (CHP) units with Photovoltaics (PV), represent a compelling pathway by simultaneously improving energy efficiency and minimising environmental impacts.

This study assesses the techno-economic feasibility of a HRES combining two biogas-powered CHP units (400 kWe total) and a 110 kW PV system in an agricultural enterprise in northern Italy. Two scenarios are analysed: one under a feed-in tariff (Scenario #1), the actual one, and another based on North market electricity prices in Italy (Scenario #2). Results show that the feed-in tariff significantly improves the economic outcomes, with Net Present Values (NPVs) exceeding €6.7 million and a PayBack Period (PBP) of around 3 years. NPV drops below €1 million without the feed-in tariff, and the PBP extends to 10-11 years.

A sensitivity analysis is also carried out by varying the electricity purchase price, using €0.18/kWh as the baseline and comparing it to €0.22/kWh. In Scenario 1, the impact of this variation is marginal: the 15-year NPV, which is approximately 6,780,000 €, decreases by only 0.6%, while the PBP remains unchanged. In contrast, Scenario 2, which relies more on energy self-consumption, exhibits greater sensitivity to electricity price changes. In this case, the NPV, starting from approximately 736,000 €, increases by about 15%, and the PBP improves slightly, shortening from approximately 10–11 years to 9–10 years.

The findings highlight the crucial role of policy incentives in promoting renewable energy adoption. However, this type of HRES remains economically viable even without feed-in tariff support, offering the added benefit of delivering stable and continuous electrical and thermal energy to a dedicated end-user.

## 1. Introduction

While the large-scale deployment of renewable energy is central to global decarbonisation strategies, complementary technologies, such as storage, grid management, and dispatchable generation, are essential to ensure reliability and long-term effectiveness [1]. Intermittent sources like solar are highly variable and weather-dependent, often causing supply-demand imbalances that threaten grid stability, especially during peak loads or adverse conditions [1].

To address this, dispatchable renewables such as biogas offer flexible, controllable power generation that can offset the intermittency of most of the renewables, such as Photovoltaic (PV) [1]. Beyond stability, biogas also supports environmental and socio-economic sustainability. A key advantage of biogas production is its ability to both valorise organic waste, such as agricultural residues, manure, food waste, and sewage sludge, and reduce methane emissions through controlled anaerobic digestion [2]. This process captures methane that would otherwise be released into the atmosphere, a gas with 28 times the global warming potential of $CO_2$ over 100 years [3]. When used in Internal Combustion Engines (ICEs), biogas also lowers emissions compared to fossil fuels, reducing CO by up to 56%, hydrocarbons by 63%, and NOx by 48% [4], thus supporting cleaner energy and transport solutions.

Hybrid Renewable Energy Systems (HRES) combine multiple renewable sources to improve energy reliability and efficiency. Panbechi et al. examined an HRES integrating biogas and PV in a small Iranian city, comparing three scenarios against a baseline combined cycle plant: (1) selling electricity to the grid, (2) producing green hydrogen, and (3) applying government subsidies for municipal waste procurement. Results show that while selling electricity to the grid reduces costs, the Internal Rate of Return (IRR) is negative (-7%) due to low local electricity prices. Green hydrogen production decreases the IRR to -17% [5]. Most importantly, government subsidies significantly enhance profitability, reducing costs drastically and generating net revenue. This highlights the essential role of incentives in making renewable projects financially viable in challenging markets. Similarly, Hüner assessed hybrid PV-biogas systems in Hatay, Turkey, using HOMER Pro. The study compared on-grid and off-grid scenarios, finding the off-grid system to be more cost-effective (LCOE 0.2094 $/kWh vs. 0.2861 $/kWh) and achieving a 95.78% reduction in $CO_2$ emissions. Biogas and PV contributed roughly 50% and 45% of energy production, respectively, underscoring the potential of local renewables for cost savings and emission reductions [6]. Kimutai et al. evaluated a hybrid photovoltaic-biogas energy system for rural communities in Kenya, identifying an average daily electricity demand of 114.75 kWh. The optimized configuration included 25.5 kW of PV modules, a 3 kW biogas generator, and 143 kWh of battery storage. The levelized cost of energy (LCOE) was calculated at $0.171/kWh. Replacing firewood with biogas for cooking resulted in an estimated annual emissions reduction of approximately 60,193 $kgCO_2eq$, with total system-related mitigation exceeding 106,000 $kgCO_2$/year [7]. This work distinguishes itself from earlier studies by exploring both incentivised and non-incentivised scenarios within the Italian context, thus providing novel insights.

This study aims to evaluate HRES within an agricultural enterprise in northern Italy, comprising a 110 kW PV array and a 2 x 200 kWe Combined Heat and Power (CHP) unit. Currently, the CHP operates under a 15-year feed-in tariff for electricity sold to the grid (Scenario #1). After this period, electricity will be sold at the North hourly zonal market price in Italy (Scenario #2). The study assesses the technical and economic impacts of both scenarios using a model-driven approach based on the Calliope framework, which applies a Mixed Integer Linear Programming (MILP) algorithm to minimise an economic objective function.

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The paper is structured as follows: Section 2 describes the methodological approach, detailing the Calliope modelling framework. Section 3 presents the case study under investigation, together with the input data and the assumptions used. Section 4 presents and discusses the results of the analysis, comparing the technical and economic performance of the two scenarios. Finally, Section 5 reports the conclusions of the work and future developments.

## 2. Materials & Methods.

This section first presents the modelling framework adopted, followed by a detailed description of the three main technologies defined.

### *2.1 Calliope Modelling Framework*

Calliope is an open-source framework designed for modelling energy systems using algorithms designed to solve MILP problems. It operates by minimising a linear objective function, subject to a set of linear constraints, as well as bound constraints on the decision variables, Additionally, some decision variables are required to take integer values, a characteristic that gives rise to the term mixed-integer. The Gurobi solver is employed to address the MILP problem using the branch-and-bound algorithm. This method begins by solving a relaxed version of the problem in which the integer constraints are temporarily excluded. If the solution obtained from this relaxation already satisfies the integrality requirements, the algorithm terminates. Otherwise, the solution is not feasible for the original MILP, and the algorithm proceeds by creating two new subproblems, or branches: one with values less than or equal to the greatest integer less than the current fractional value and the other with values greater than or equal to the smallest integer greater than the current fractional value. In the context of Calliope, the objective is to minimise overall system costs by optimising technology deployment and operation across multiple locations (Eq. (1)).

$$\min : z = \sum_y (weight(y) * \sum_x cost(y, x, k = k_m)) \quad [8] \tag{1}$$

where $y$ denotes the technologies, $x$ denotes the locations, $k$ represents general cost categories, which may include monetary costs or environmental costs, and *km* specifies that the cost category considered by default is monetary. The term *weight(y)* is a technology-specific weighting factor, set to 1 by default but adjustable to alter the relative importance of each technology's costs in the optimisation.

End-users can define technologies, demands, and constraints via .yaml configuration files, making the framework suitable for a wide range of applications, from local microgrids to national-scale systems. The framework is organised around four main .yaml files: locations, techs, scenarios, and model. The locations file specifies the spatial dimension of the model, listing the geographic nodes and specifying the technologies assigned to each. It also serves as the point where the demand .csv file and the files containing export cost data are linked to the model. The tech file describes the technical and economic parameters of each technology. Technologies are divided into five main types: supply, conversion, demand, storage, and transmission. Supply represents technologies that introduce energy into the system by converting a resource into a carrier. This includes both local sources (e.g., renewables, fossil fuels, etc.) and external sources such as grid imports. Conversion refers to technologies that transform energy from one carrier to another, such as CHP units.

To provide further information, Sections 2.2, 2.3, and 2.4 present detailed models of the biogas, CHP, and PV technologies, respectively. Notably, the biogas technology is not natively supported within the Calliope framework and was therefore custom-developed specifically for this study. In this work, the planning mode provides the cost-optimal energy system configuration [8].

*2.2 Biogas Technology Model*

The biogas technology is modelled as a “supply plus” technology. The main constraint applied is an "energy cap max", representing the maximum capacity threshold, which is set to infinity. An additional constraint concerns the efficiency, fixed at 60%, which reflects the ratio between the chemical energy content of methane and the energy contained in the input substrates [9]. The model defines two main types of monetary costs: the energy capacity cost, expressed in [€/kW], which represents the investment cost, and the variable operation and maintenance cost (O&M) given in [€/kWh]. The main parameters used in the model for biogas technology are presented in Table 1.

**Table 1-** Technology parameters.

| | Constraints | | | Costs | |
|---|---|---|---|---|---|
| | Energy cap max (kW) | Lifetime (years) | Energy efficiency (%) | Energy cap (€/kW) | O&M (€/kWh) |
| Biogas | Inf. | 25 | 60% [9] | 2,700 [11] | 0.02 [12] |
| CHP | Inf. | 25 | 41 | 2,300 [13] | 0.013 |
| PV | Inf. | 25 | 85 [8, 18] | 900 | 9 [a] |

[a] Expressed as €/kW.

The energy balance is reported in Eq. (2), where *r* represents the resource of technology *y* at location *x* and time *t*, and cprod represents the production carrier flows. The term *totaleff* represents the overall efficiency, including parasitic losses. The term $r_2$ corresponds to the secondary resource and is set to zero unless the technology explicitly includes a secondary resource.

$$r(y,x,t) = cprod \; - r2 \tag{2}$$

*2.3 CHP Technology Model*

The CHP technology is defined as a "conversion plus" technology, which allows for multiple output carriers, with electricity as the primary output and heat as the secondary one. The specified energy efficiency applies to the primary energy carrier (electricity). To account for the secondary output, an additional parameter must be defined: “carrier_ratios.carrier_out_2.heat”, which represents the amount of heat generated per unit of electricity produced. According to the technical datasheet of the CHP unit, the electrical output power of one CHP is 220 kWe and the thermal output power is 234 kWh, resulting in a heat-to-electricity ratio of approximately 1.06.

The max. energy capacity is set to “Inf” as in Subsection 2.2. The difference between the two scenarios analysed lies in the definition of monetary revenues coming from the CHP model. In the first scenario, where the 15-year feed-in tariff is applied, the electricity sold to the grid is €0.28/kWh following the Italian Law No. 244/2007 [10]. In the second scenario, instead, where no feed-in tariff is applied, electricity exports are sold at the hourly zonal market price. The main parameters used in the model for CHP technology are presented in Table 1.

The energy balance relationship in Eq. (3) models the conversion process within the “conversion plus” technology in Calliope. Here, $c_{prod}$ refers to the amount of electricity produced as the primary output carrier, and $c_{con}$ indicates the biogas consumption. The term carrier fraction quantifies the proportional contribution of each carrier to the overall energy exchange, and $e_{eff}$ is the conversion efficiency.

$$\sum_{c_{out1}} \frac{c_{prod}(c_{out1}, y, x, t)}{carrier_{fraction}(c_{out1})} = -1 * \sum_{c_{in1}} c_{con}(c_{in1}, y, x, t) * carrier_{fraction}(c_{in1}) * e_{eff}(x, y, t) \quad (3)$$

*2.4 PV technology model*

The PV technology is defined as a "supply plus" technology, where the resource constraint is provided via a .csv file containing solar irradiance data sourced from “Renewables.ninja” [11]. The dataset refers to the specific location in northern Italy and a panel tilt angle of 30°, and a south-facing orientation, and already accounts for panel efficiency. In this configuration, the resource values are expressed in kWh per unit of installed energy capacity. In both scenarios, the electricity sold to the grid follows the North Italy electricity market prices. The average price for 2024 is €0.107/kWh [17]. In this case, the energy efficiency is set to 85%, representing parasitic losses due to the inverter's use. This value is supported by findings in the scientific literature, where reported inverter efficiencies commonly range between 80% and 90% [18]. The main parameters used in the model for PV technology are presented in Table 1. The energy balance for this technology follows the same formulation presented in Eq. (2).

*2.5 Economic Evaluation*

The economic analysis is carried out over 15 years for both scenarios, corresponding to the duration of the feed-in tariff applied to electricity generated by CHP systems and sold to the grid. The economic feasibility is evaluated through both Net Present Value (NPV) and PayBack period (PBP). Investment costs are derived from the "energy cap" values reported in Table 1, which represent the investment cost per unit of installed capacity, multiplied by the capacity sizes of the respective technologies. Similarly, the O&M costs are obtained by multiplying the unit operating cost by the total amount of energy produced over one year. Furthermore, the cost of electricity purchased from the grid is also included among the negative cash flows, exclusively in Scenario 1, where part of the energy demand is met through grid imports. Positive cash flows, on the other hand, include revenues from electricity sold by the CHP and PV systems, as well as savings from self-consumption based on the electricity tariff that the agricultural enterprise pays to the energy contractor. Cash flows are discounted using technology-specific discount rates: 8.5 % for the biogas technology, 5% for the CHP technology, and 9% for the PV technology according to [14-16].

*3. Case study*

The HRES under investiagtion, which is related to an agricultural enterprise in northern Italy, is schematised in Fig. 1. The digesters are fed with a mixture of swine slurry and dedicated energy crops, such as silage maise, and agricultural by-products like wheat bran and wheat stillage which together serve as the primary substrate for the anaerobic digestion process.

The biogas produced is used as fuel for a CHP system. The CHP unit generates electricity that, in Scenario #1, is either sold to the grid under a feed-in tariff scheme or, in Scenario #2, without incentives, self-consumed, with any surplus exported to the grid at the hourly zonal market price in Northern Italy. The thermal output of the CHP system is used both to heat the digesters and provide thermal energy for residential use. Additionally, a PV system installed on the shed roof produces electricity that is primarily used for self-consumption, with any excess similarly sold to the grid at the hourly zonal market price.

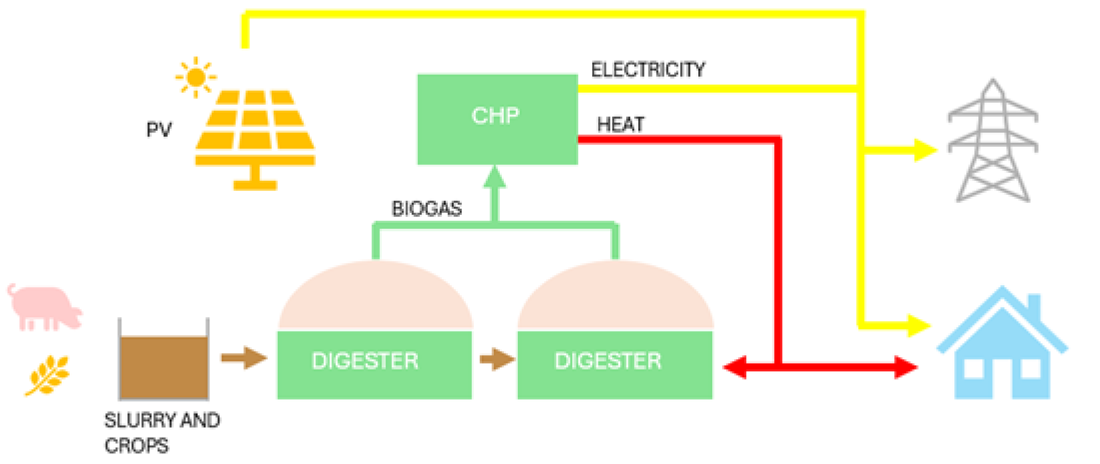


**Figure 1.** Scheme of HRES

The electrical and thermal load data were provided by the agricultural enterprise, and the representative daily load curve is illustrated in Fig. 2. It refers to January 8$^{th}$, identified as the day with the highest combined electrical and thermal demand, and thus the most energy-intensive day of the year. The data refer to the year 2024, and the same annual consumption profile has been replicated across the 15-year analysis period. Concerning the heat load, the data reported in Fig.2 refer exclusively to the heating demand of the residential buildings. In addition, a constant thermal load of 400 kW, corresponding to the heat demand of the digesters, is considered on an hourly basis, which has not been inserted in Fig. 2 since it is constant throughout the year and not comparable, in terms of order of magnitude, with the loads shown.

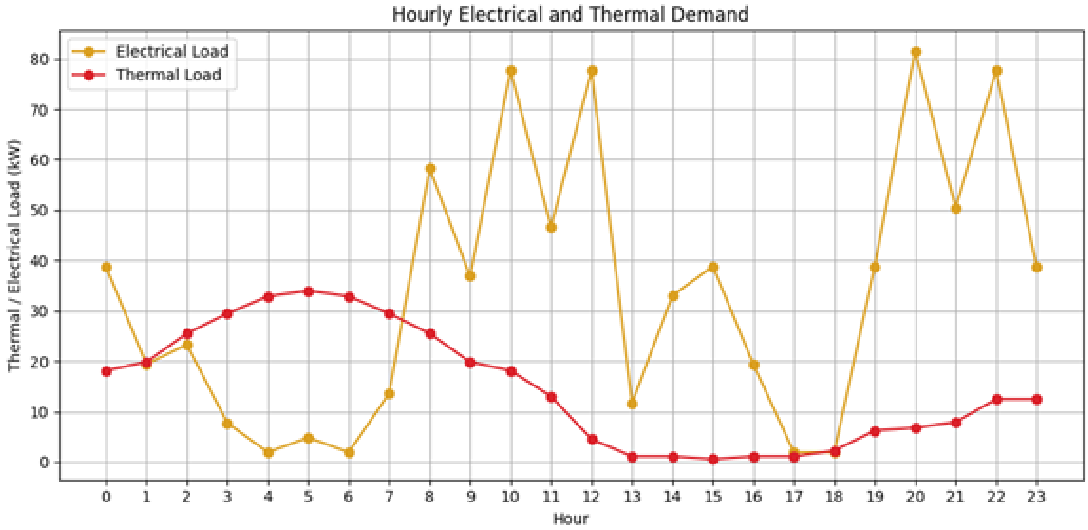


**Figure 2.** Electrical and thermal load, on 8th January 2024

Table 2, on the other hand, reports the total annual electrical and thermal load, broken down into residential demand and that of the digesters. The electrical energy self-consumption of the biogas cogeneration plant has been estimated at approximately 7% of the total electrical output, as documented in the relevant case study [19].

**Table 2** – Annual load requirement

| | Electrical load | Thermal load |
|---|---|---|
| Total | 262.4 MWh | 3.58 GWh |
| Plant (digesters, CHP, and auxiliars) | 233.6 MWh [19] | 3.5 GWh |
| Residential | 28.8 MWh | 80 MWh |

## 4. Results and discussion

In this section, the main energy and economic results coming from Scenario #1 (15-year feed-in tariff from the electricity produced with the CHP and sold to the grid) and Scenario #2 (no 15-year feed-in tariff from the electricity produced with the CHP and sold to the grid) are reported. From an energy standpoint, the main difference between the two cases is that, in the first case, all the electricity generated by the CHP system is fully sold to the electric grid under the feed-in tariff scheme, as it is more economically advantageous. On the other hand, part of the electricity produced by the PV is self-consumed whereas the remaining amount is sold to the grid, as illustrated in Fig. 3. In contrast, in the second scenario, there is no electricity import from the grid, as the electricity generated is first used to cover on-site energy consumption, and any excess is subsequently exported to the grid. This result is due to the greater economic advantage of consuming the generated energy rather than purchasing electricity from the grid. In fact, the average hourly zonal market price in 2024 is 0.107 €/kWh [17], which is significantly lower than the electricity purchase price for the agricultural enterprise of 0.18 €/kWh.

### *4.1 Scenario #1 analysis*

Scenario #1, validated using the actual power ratings of both the installed CHP and PV systems, is illustrated in Figure 3, where only the electrical output of the CHP is represented. In this configuration, it can be observed that the electricity generated by the CHP unit is entirely exported to the grid, as the CHP production exactly matches the amount of electricity exported. This confirms that the CHP output does not contribute to meeting on-site electrical demand. The same day of Fig. 2 has been considered in this case, as the operational pattern of the CHP unit remains consistent throughout the year.

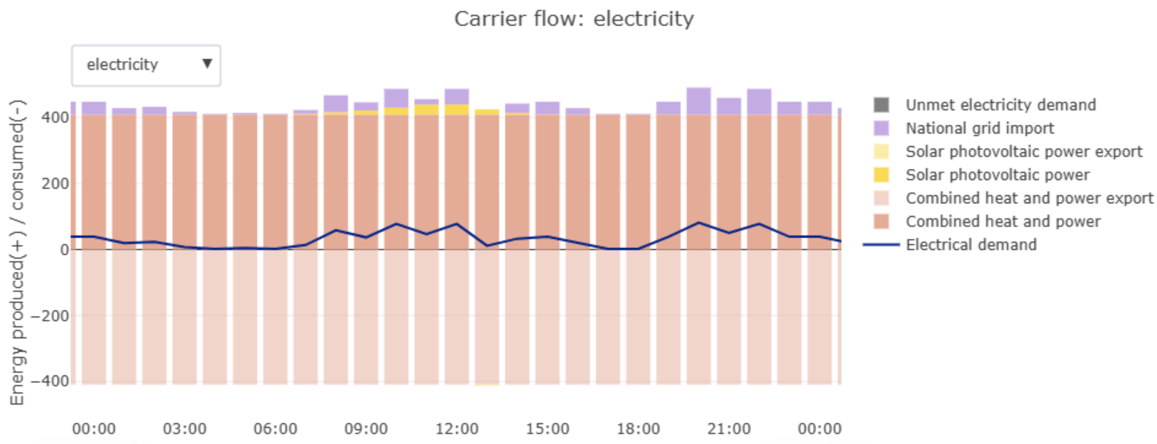


**Figure 3.** Electrical demand and total on-site generation, including CHP, on 8th January 2024

Figure 4, on the other hand, illustrates the same scenario on a representative day for each season, with CHP electricity production and export to the grid not reported. This configuration is

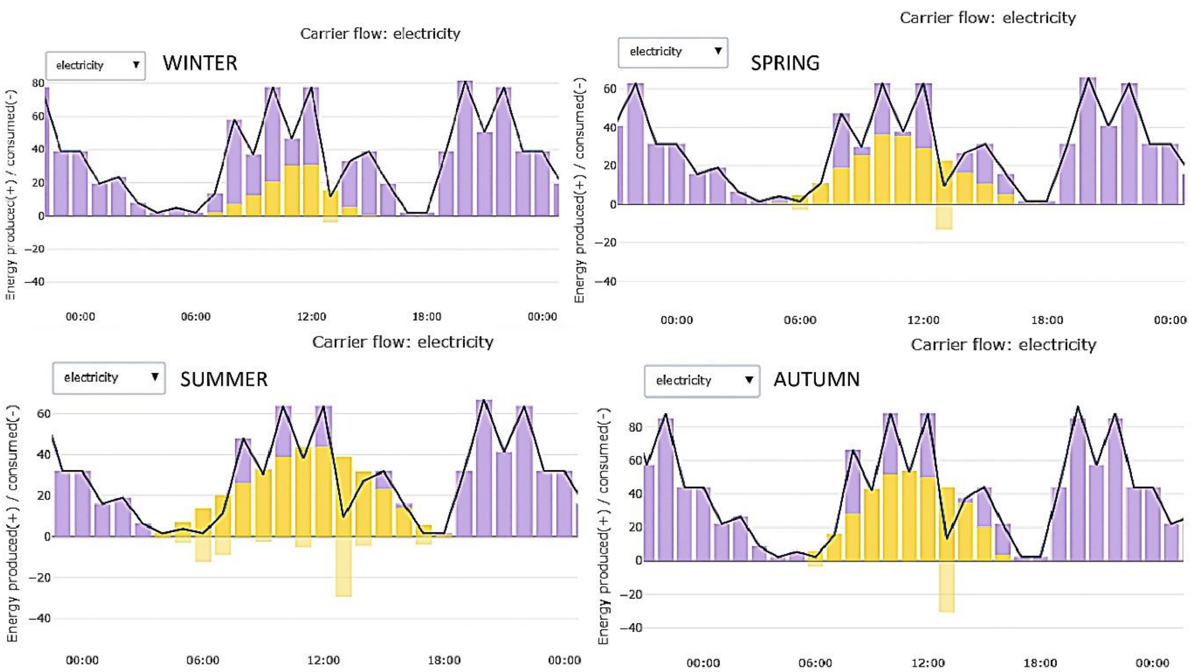


**Figure 4.** Electrical demand and PV production for a representative day in each season (8th January, 10th April, 4th July, 10th October)

intended to highlight the profile of local electrical demand alongside PV generation more clearly. The exclusion of CHP output allows for a better understanding of the balance between on-site demand and PV supply, without the overlay of exported electricity.

On the thermal side, Fig. 5 presents the heat demand and the corresponding exclusively thermal energy production by the CHP system. January 8th, the day with the peak heat demand, is shown. It can be observed that the CHP system is sized to fully cover the total thermal load, which consists of a constant load of 400 kW from the digesters and a variable residential load, peaking at 34 kW. This analysis highlights that the CHP system is heat-led, meaning that it is designed to match the heat requirements first, particularly the constant load from the digesters.

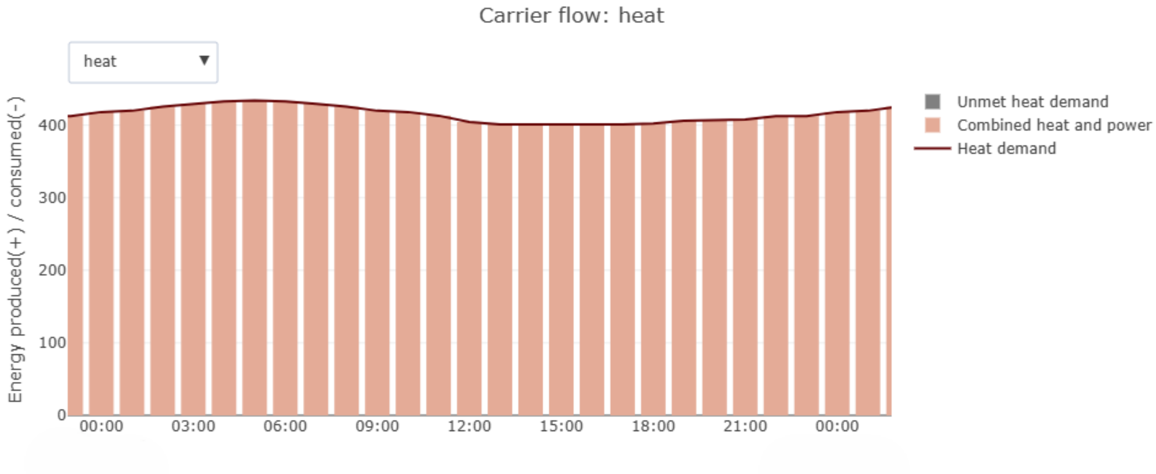


**Figure 5.** Thermal demand and CHP production, on 8th January 2024

Fig. 6 illustrates the NPV trend for Scenario #1, showing limited sensitivity to electricity purchase price variations. After 15 years, the NPV remains above €6.7 million for both 0.18 and 0.22 €/kWh, with a consistent PBP between the third and fourth year.

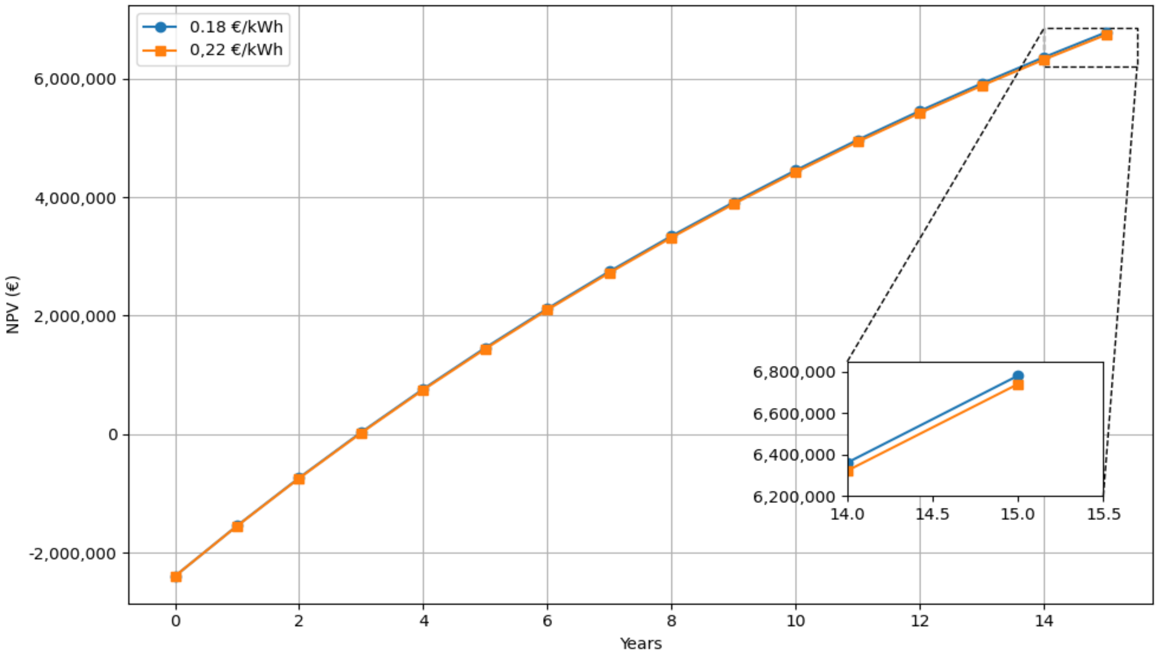


**Figure 6.** NPV trend of Scenario #1 with electricity purchase price of 0.18 and 0.22 €/kWh.

*4.2 Scenario #2 analysis*

In this case, the electrical demand is fully covered by both the CHP and PV systems, as illustrated in Figure 7. This can be observed from the fact that, when the demand is not zero, the electricity exported to the grid from the CHP and PV systems does not match its total production, indicating that part of the generated electricity is used to satisfy on-site energy demand. The figure presents electricity demand and production on 8th January, which is considered indicative of all seasons. Although CHP production is primarily driven by heat demand, its seasonal variation is limited due to the dominant and stable base load provided by the digesters.

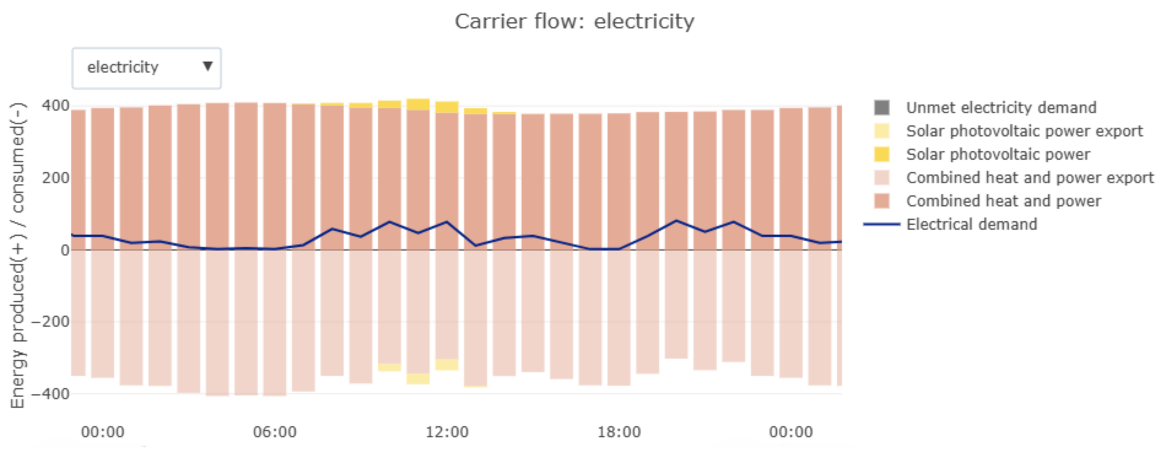


**Figure 7.** Electrical demand and electricity production from PV and CHP

The thermal behaviour in this scenario is the same as in the previous one, with the CHP system fully covering the constant and variable heat demand. This confirms that the system remains heat-led, with no changes in thermal energy production or load profiles. From an economic perspective, this scenario is less advantageous, with an NPV after 15 years of approximately 736,000 € and PBP between 10 and 11 years, assuming an electricity purchase price of 0.18 €/kWh. In case the electricity purchase price increases to 0.22 €/kWh, the NPV after 15 years rises to approximately 846,000 €, with a PBP of 9.9 years.

This increase is attributable to the higher economic value of the electricity savings, as the electricity not purchased results in greater monetary savings at the elevated purchase price. As illustrated in Figure 8, the distinction between the curves corresponding to different price values is more evident.

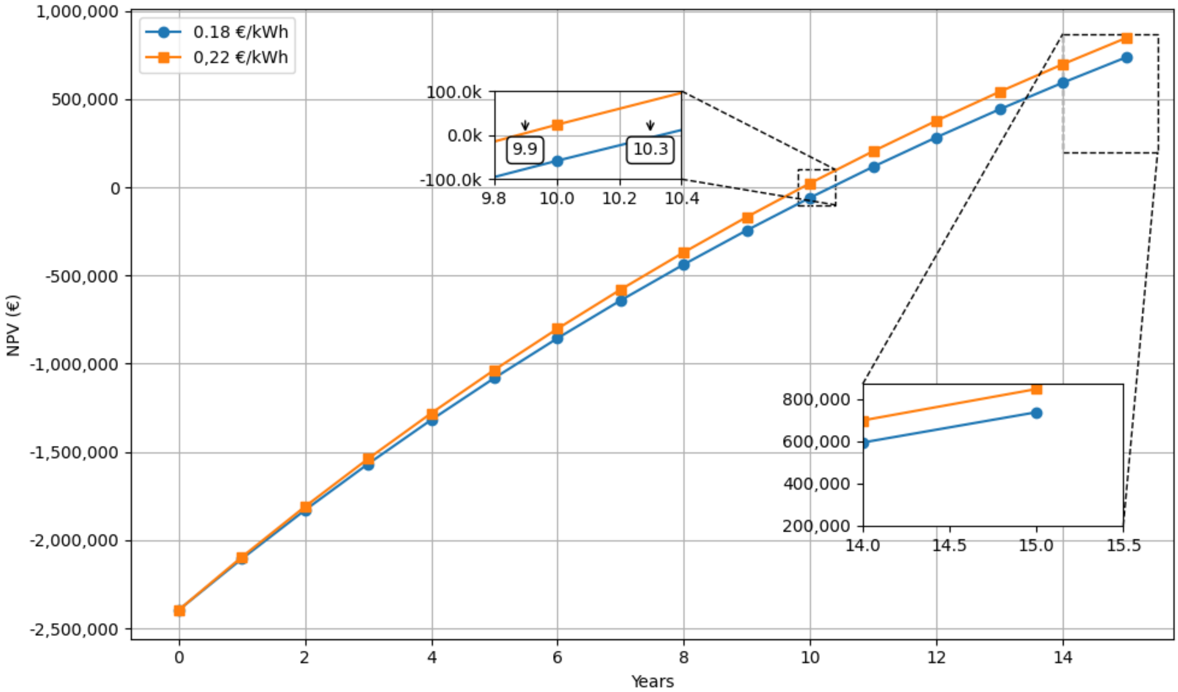


**Figure 8.** NPV trend of hourly zonal market prices case with electricity purchase price of 0.18 €/kWh and 0.22 €/kWh

The comparative analysis of Scenario #1 and Scenario #2 reveals distinct differences in both energy management and economic outcomes, primarily driven by the availability of a feed-in tariff for CHP-generated electricity. From an energy perspective, Scenario #1 involves the complete export of electricity produced by the CHP system under the feed-in tariff scheme, as this maximises economic returns. Local electrical demand is primarily met by PV, which is partially self-consumed and partially exported. In contrast, Scenario #2 prioritises on-site consumption of both CHP and PV electricity, thereby reducing the need for electricity imports from the grid.

Economically, Scenario #1 shows significantly better performance, with an NPV of approximately €6.78 million and a PBP of 3 years, assuming an electricity purchase price of 0.18€/kWh. The sensitivity analysis demonstrates limited sensitivity to electricity price variations. Scenario #2, lacking the feed-in tariff, yields a substantially lower NPV of ca. €736,000 and a longer PBP (10–11 years). However, its economic performance improves as the electricity purchase price increases, indicating a greater dependence on energy market conditions. Finally, Scenario #1 is economically favourable in the presence of policy incentives, while Scenario #2 may be more appropriate in contexts prioritising self-consumption.

## 5. Conclusions

This study has demonstrated the technical and economic viability of a HRES integrating biogas-fuelled CHP units and PV panels within an agricultural enterprise in northern Italy. The findings indicate that policy support mechanisms considerably enhance economic performance, resulting in an NPV exceeding €6.7 million and a PBP of approximately 3 years. Even in the absence of such incentives, the system remains economically attractive, with an NPV of approximately €800,000 and a PBP of 10–11 years over 15 years.

Looking ahead, future research should explore the integration of both electrical and thermal energy storage systems, which could further enhance energy self-consumption rates and increase system flexibility. Storage integration would facilitate a better temporal match between energy production and on-site demand, thereby reducing grid dependency, technology sizes, and improving the overall economic performance.

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