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Small-Scale Hybrid Photovoltaic-Biomass Systems Feasibility Analysis for Higher Education Buildings

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Received: 30 September 2020; Accepted: 5 November 2020; Published: 9 November 2020

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Abstract: Applications of renewable electricity in cities are mostly limited to photovoltaics, and they need other renewable sources, batteries, and the grid to guarantee reliability. This paper proposes a hybrid system, combining biomass and photovoltaics, to supply electricity to educational buildings. This system is reliable and provides at least 50% of electricity based on renewable sources. Buildings with small (<500 kW) installed power based on renewables, mainly biomass, are usually expensive. Besides, in urban areas, photovoltaic capacity is limited due to roof availability. This paper analyzes different configurations, meeting these constraints to obtain an economically feasible solution based on photovoltaic-biomass modelling of small size hybrid systems. The technology used for biomass energy valorization is a fluidized bed gasification power plant, which has been modelled with real data obtained from experimental tests and previous research projects. Thereby, real costs and electric efficiency are included in the model. The techno-economic feasibility analysis using HOMER software with metered real load curves from an educational building has been modelled. The results of the model show that hybrid renewable systems are very feasible in the scenario of 50% of electricity contribution, however, higher contribution (>70%) implies high electricity costs.

Keywords: higher education buildings; Hybrid systems; Renewables systems

1. Introduction

The world energy scenario and implemented policies over the last 30 years show an important increase in energy efficiency and contribution of renewable sources, but they can only partially alleviate or soften the continuous increase in energy demand due to unstoppable population growth and necessary development of rural areas [1]. Electricity generation is one of the largest sources of CO_2 emissions. To reduce greenhouse emissions, higher efforts must be addressed for the massive implementation of renewable sources [2]. Energy-related CO_2 emissions increase 6% from 33 Gt in 2015 to 35 Gt in 2050 under current and planned policies [3]. The Vision 2050 of the European Commission has set important goals in the energy sector to protect the environment, create affordable and market-based energy services, and ensure security, reliability, and resilience of the energy supply [4,5].

Significant carbon emission reductions can be achieved with different renewables, but fossil fuels, like natural gas, usually provide the dispatchable power capacity for reliable electricity generation [6]. It must be taken into account that wind power's intermittency (and it could be extended to photovoltaics and other intermittent sources) makes that fossil gas-fired generation systems work at partial load (when wind production is temporally high) and reduced efficiency most of the time to follow load request [1,7]. It is desirable, thinking towards a massive deployment of renewables, that these systems minimize the need for conventional generation power plants.

Renewable power systems are mature technologies that should allow progressive substitution of conventional fossil technologies [8,9], however, the feasibility of this substitution is not so attractive due to economics and reliability concerns. Possible solutions to face these feasibility concerns can be based on the combination of different renewable sources (hybrid systems) and energy storage systems. Hybrid Renewable Energy Systems (HRES) can be defined as systems composed of at least one conventional and one renewable energy source, or more than one renewable and maybe including energy storage [10,11]. An HRES based on more than one renewable source will support local energy demands more efficiently than just one renewable energy installation due to the hourly changing regional weather and irradiation conditions [12]. The simplest HRES could combine photovoltaic and diesel systems, providing high reliability due to the availability of a diesel system that provides the needed electricity when the solar system cannot cover the electricity demand (lack of solar radiation, failure in the system, etc.). Nevertheless, this kind of HRES presents environmental and economic drawbacks due to the emissions coming from the use of fossil fuels and the cost to supply the diesel. Energy storage combined with higher photovoltaic installed power can be added to the HRES, accumulating the excess of electricity in batteries [13] and so reducing Diesel dependence [14]. Going further, a better solution can be the combination of photovoltaic with other renewable sources such as biomass (substituting totally or partially the diesel generator) or wind systems [15–17]. In all these configurations energy storage can also be accomplished by generating and storing hydrogen, which is later used in fuel cell systems to generate electricity when needed [18,19].

Distributed small/medium size HRES can minimize electricity grid consumption in the buildings of the EU, and since the building sector accounts for 35%−40% [20] of the total final energy consumption in EU−28 and 25–40% of the associated carbon dioxide (CO_2) emissions, this alternative must be analyzed. This paper is focused on this analysis for higher education buildings.

This paper presents an exhaustive feasibility analysis of the implementation of an HRES on a higher education building (university), performed using a complete year of energy demand measurements of an existing building, real costs and efficiency of small biomass gasification power plants, and HOMER software for an economic/technical feasibility simulation.

2. Materials and Methods

A feasibility analysis of the hybrid system has been performed using HOMER simulation software [21], which is commonly used for economic and environmental feasibility analysis of HRES systems and provides a very efficient tool for case studies and policy analysis [22–25]. The HOMER tool performs the simulation, optimization, and sensitivity analysis of energy systems. Technical and economic feasibility assessment is based on hourly energy balances for different system configurations.

The HOMER tool selected configurations should meet the electricity and thermal demand and must satisfy all technical, economic, and environmental constraints imposed by the user. Then it calculates the total net present cost (NPC), which is the present value of all equipment capital (initial investment), equipment replacement costs, and operating costs during the project lifetime.

HOMER has some limitations, among them, it could be mentioned that the quantity and quality of data are required to have good results (Hourly data are required), and it is sometimes difficult to find data with such a resolution. Besides, it is required to give the sizes (Rated power) of the source to be analyzed, and from this information, the final solution will be obtained; HOMER does not take into account sizes out of the given, therefore, the most suitable solution could be missed.

The energy resources are solar and biomass. The solar resource used for the analysis refers to Valencia (Spain) with a location of 39°28′N latitude and 0°22′E longitude, whose solar data comes from the NASA Surface Meteorology and Solar Energy website (http://eosweb.larc.nasa.gov/sse/). The annual average solar radiation was scaled to be 4.49 kWh/m^2·day.

Some of the main input data as biomass gasification power plant (BGPP) efficiency and electricity demand load curve (hourly values, whole year cycle) of the building come from pilot plant experimentation and real metering, respectively. Several BGPP sizes will be considered, from 10 to 100 kW, taking into account the size effect on efficiency and, mainly, on installed costs.

2.1. Building Load and Resources Assessment

The selected building is a typical higher education building located in Valencia (Spain) and composed mainly of classrooms and offices. It has four floors and a total indoor extended area of about 3950 m^2, with a total roof area of 1020 m^2. Building total consumption has been metered for several years with a power meter (Schneider, model PM710,) every 15 minutes. Data included in this article refers to 2019 (from 1/01/2019 to 31/12/2019. Figures 1 and 2 include, respectively, typical daily profiles (for winter, summer, and neutral months as of February, June, and October) and a monthly profile of power needs. In the seasonal profile, the mean (average), the minimum and the maximum power of monthly average daily profiles, and absolute minimum and maximum power needs of each month are included.

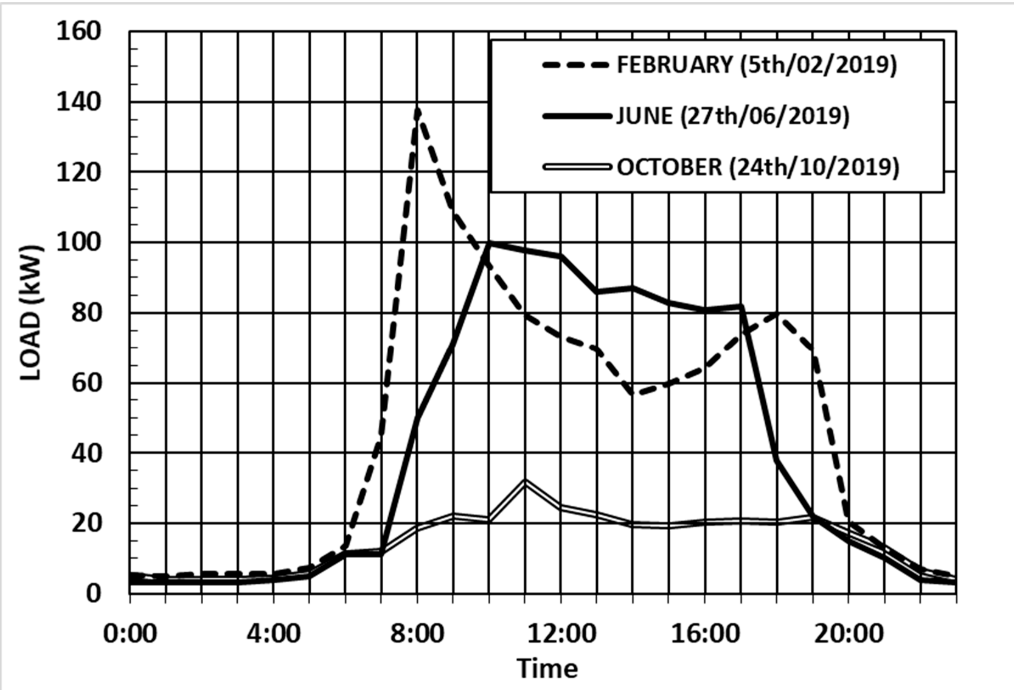

Figure 1. Typical daily load profiles for February, June, and October.

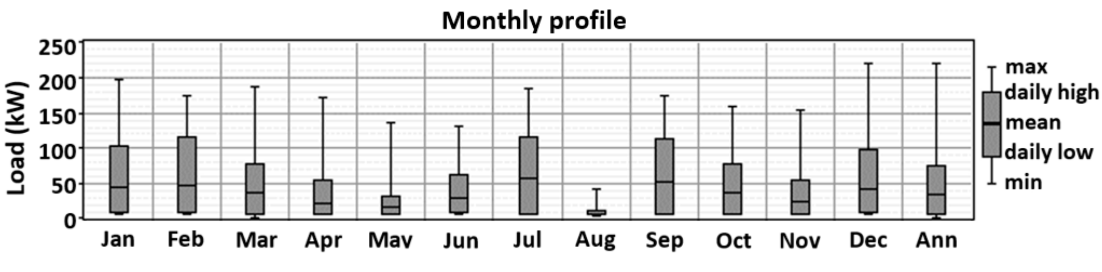

Figure 2. Typical seasonal profile of daily average and peak load (weekdays).

Average daily electricity consumption is about 534 kWh/day, and annual peak power is 201 kW, and the daily load factor (average power referred to the peak power of the day) ranges from 0.31 to 0.79 (average of 0.55 and standard deviation of 0.24). Typically, the building electricity consumption is concentrated from Monday to Friday (from 7:30 in the morning to 20:30). The main energy use is space heating and cooling, which is supplied by electrical heat pumps. Regarding HOMER software inputs, the building load curve has been considered as Primary Load 1 with no deferrable loads. Daily high and daily low in Figure 2 refers to the average maximum and minimum power of monthly average load curves.

Biomass considered for the biomass gasification plant corresponds to commercial pellets with High Heating Value (HHV) of 18.1 MJ/kg, 1–1.2% of ash content, and 7.4–8.5% of moisture content, which were tested in the experimental BGPP (the Biomass Gasification Power Plant, described in point 2.2). In the feasibility analysis, a market cost of pellets of 225 €/t has been considered [26], however, for the sensitivity analysis, lower prices corresponding to operation with commercial chips (around 75–125 €/t) and pellets from agricultural and forestry waste biomass coming from neighbor counties (150–175 €/t) have been considered. These local biomass resources and feasibility of pellet plants were evaluated in previous projects as BIOVAL ("Optimization of the Energy Use of Biomass Resources in the Valencian Region", 2005–2006, was a project funded by the regional government of the Valencian region—IMPIVA, Generalitat Valenciana—and the European Fund of Regional Development) and publications [27,28] and, with a pellet price of 150 €/t, payback periods were acceptable, in the range of 5–7 years. Pellets produced with these local biomass resources (mainly from forestry and crops) can be considered similar to commercial. The pellets' average properties on a dry basis were 17.6–18.5 MJ/kg for HHV and 1.9–2.0% ash content. Considering counties near Valencia city and maximum transport distances of 35 km, biomass resources were in the range of 130,000–145,000 t/year (corresponding counties: El camp de Turia, El camp de Morvedre, La Hoya de Buñol, and La Ribera Alta).

2.2. *Components Assessment and Economic Modeling*

In a hybrid power system, a component generates, converts, delivers, or stores energy. In the present HOMER analysis, the photovoltaic plant (PV) is the intermittent resource, and the BGPP is kept for backup purposes or to increase renewable energy production when PV power is limited due to roof area availability. Batteries and associated converters are used for storing and converting electricity (see Figure 3 for a schematic system configuration diagram). The loads, the BGPP, and the photovoltaic plant are connected to the AC side of the utility grid, and the batteries are connected to its DC side. The grid connection is only used for comparison purposes and, when necessary, to cover peak power needs. The performance and cost of each component is the main factor for the cost results and design process.

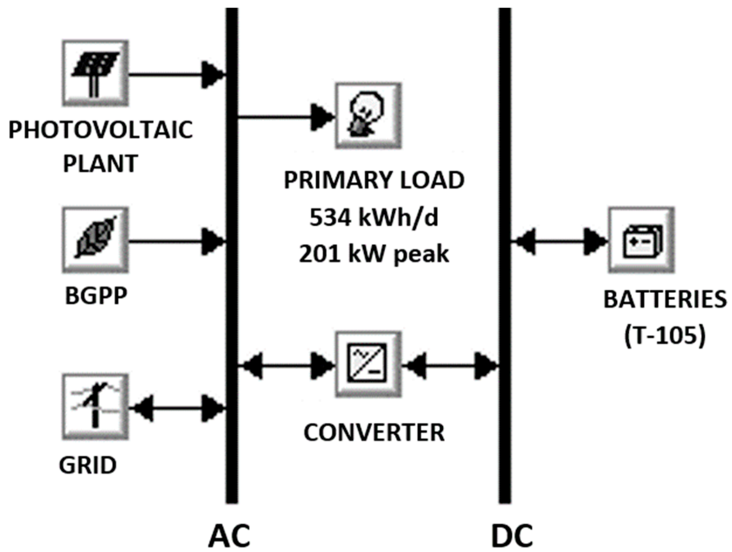

Figure 3. Schematic hybrid system configuration.

The photovoltaic panels considered are wafer-based crystalline silicon technology (over 95 % of current world production [29]) with a typical efficiency ranging from 17 to 21%. For simulation purposes, a derating factor of 90% has been considered (10% of losses are due to soiling, wiring losses, and aging). The capital cost and replacement cost for a 1 kW PV system is taken as 1100 € [30] and 700 €, respectively. Regarding replacement cost, PV cost reduction estimations for 2045 have been considered [30]. Little maintenance is required for PV, usually around 1% of the investment cost [31]. In the Spanish national plan for renewable energies for the period 2011–2020 [32], it is considered a representative annual O&M (operation and maintenance of the system, also including insurances and management) cost (including insurances and management) of 30 €/year·kW^{-1}, so it will be considered this cost for the analysis. In the following paragraphs, the costs per kW include installation, logistics, and other minor costs. The PV panels are modeled as fixed (no tracking system), and a lifetime of 25 years has been considered. For the feasibility analysis, an installed power in the range of 0–80 kW has been considered, as roof availability is about 750–850 m^2 (≈67–76% of total roof area) for the studied building, considering the specific area needs of 10 m^2/kW.

The elements of the biomass gasification power plant are a bubbling fluid bed reactor, a biomass feeding system, a gas cleaning system (cyclone and multi-stage filter), a cooling system (shell and tube heat exchanger), an internal combustion engine for power generation, and the control and monitoring system (Table 1). The experimental BGPP tested in LabDER (Distributed Energy Resources Laboratory of the IUIEE) [1,9,23] has a maximum output of 10 kW with an input of 11–13 kg/h of biomass (with 10% of moisture). For this biomass flow, it produces about 27 to 33 Nm^3/h of syngas, which is burnt in the Genset to produce electricity. Table 1 [1] includes the main features of the experimental BGPP and Figure 4 shows experimental behavior in terms of efficiency (calculated as electricity to biomass input in terms of energy, where biomass is expressed by HHV and corresponds to pellets with a moisture content of 7.2%), power output, and biomass consumption (further information about BGPP and LabDER laboratory equipment can be found in previous publications [1,9,23]). For the feasibility analysis, a BGPP in the range of 0–100 kW has been considered. Nominal and partial load electric efficiency has been considered as the tested experimental BGPP (see Figure 4), minimum partial load, for simulation purposes, has been stated as 50%.

For economic modeling, the cost breakdown of a 10 kW and 52 kW BGPP (Table 2) has been carried out [33], and the specific cost was 5758 €/kW and 2151 €/kW, respectively. Replacement cost has been calculated considering a lifetime of 20,000 h and includes substitution cost of the internal combustion engine and 20% of the initial investment cost of the main equipment, instrumentation, and automation.

Table 1. Datasheet of the biomass gasification plant used for the simulations [1].

Biomass Gasifier (Reactor Type)	Bubbling Fluidized Bed
Biomass reactor dimensions	Diameter: 106 mm, Height: 155 mm
Material	Stainless Steel
Fuel type	Wood chips < 5–15 mm length Pellets (diameter 6 mm, 15–25 mm length)
Biomass hopper capacity	237 liter (40 to 166 kg of biomass depending on biomass bulk density)
Biomass screw feeder diameter	screw conveyor: 55 mm in diameter
Biomass input (10% moisture)	11 kg/h (from 5 to 13 kg/h)
	55 kWt (from 30 to 65 kWt of thermal power, referred to wet biomass Higher Heating value)
Syngas production	12–30 Nm^3/h
Syngas Higher Heating Value	5–5.8 MJ/Nm^3
Total Efficiency	14–14.3%HHV (at nominal power)
Metering system (connected to data acquisition system)	8 temperatures, thermocouple type K 8 differential pressures, 0–100 mbar range 2 gas flow meter
Control and communications	PLC OMRON, model CJ2M with serial communication RS-485. 2 Frequency inverters (OMRON V1000) for the regulation of biomass and air inlets.
Power generation engine	Cylinder capacity: 1.8 liter Engine velocity: 1500 rpm Compression ratio: 8.5: 1 Rated Power: 10 kW [220/240 V & 50 Hz]

Regarding the BGPP O&M cost, it has been assessed considering an O&M cost of a fluidized bed biomass gasification plant, about 0.023 €/kWh [9,34]. The total O&M costs are 0.041 €/kWh. For a 50 kW BGPP operating 2500–3000 h/year, it would be around 5100–6150 €, which means an average of 5–8 h per week for maintenance (considering an hourly cost of 16 €/h and operation of 5–7 days per week). The nominal Operating period during weekdays is from 8:00 to 18:00, and it can be extended from 5:00 to 21:00 depending on economic feasibility (economic optimization). Likewise, during the weekend, the operation can be from 5:00 to 21:00 depending on economic feasibility.

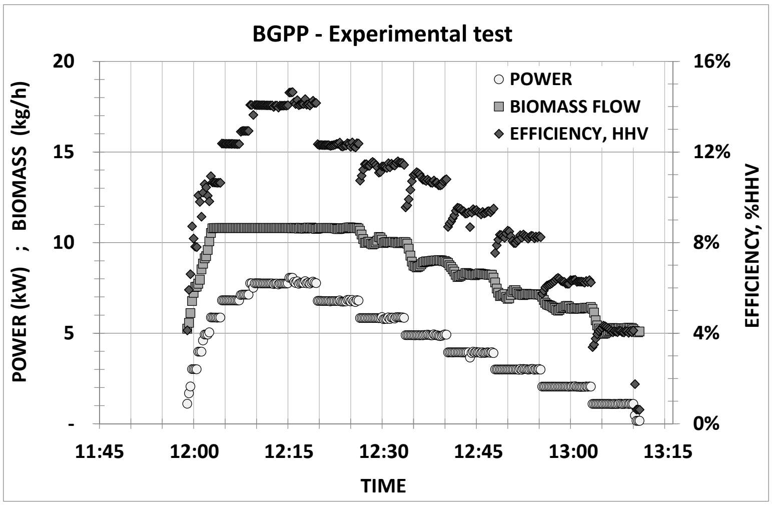

Figure 4. BGPP (biomass gasification power plant) test with pellets. Efficiency at nominal and partial load [1].

Table 2. Cost breakdown of biomass gasification power plant (BGPP).

	Power (kW)	**10**	**52**
	Biomass Bubbling Fluidized Bed Gasification Power Plant Costs (€)		
Main elements manufacturing and structural assembling	Biomass feeding system, a bubbling fluid bed reactor, gas cleaning system (cyclone a multi-stage filter), gas cooling system (shell and tube heat exchanger), and metallic structure.	14,000	28,000
Main equipment	Equipment: Water pump, water cooler, vacuum pump, screw feeder motor with speed reduction	2730	4100
Other equipment and materials	Automatic and manual valves, piping, sealing materials, other	1500	2500
Instrumentation	2 power meters, 8 temperatures, thermocouple type K, 8 differential pressures (0–100 mbar range), 2 gas flow meter, 1 water flow meter	3400	3400
Electric panel board, Automatization and control equipment.	PLC OMRON, model CJ2M with serial communication RS-485. Including modules for analogic and digital inputs 2 Frequency inverters (OMRON V1000) for the control of biomass and air inlets NB7 Operator Interface Terminal Other equipment Electric panel board and protections	4700	4700
Power generation engine	Engine velocity 1500 rpm [220/240 V & 50 Hz] Grid connection equipment	8000	34,250
Whole system design, assembling, programming, and testing	Includes company commercial benefits	23,250	34,900
	TOTAL COST (€)	57,580	111,850

Selected commercial batteries for the hybrid system are Trojan T-105 Deep-Cycle Flooded Lead Acid Battery (module of 225 Ah, 6V, with round trip efficiency of 85% and maximum discharge power of 1.5 kW). A maximum lifetime throughput of 850 kWh has been considered (according to manufacturer specifications considering 1000–2000 cycles with a depth of discharge of 30–80%), or in case of low energy use, a maximum 10 years of lifetime. Regarding O&M cost, the considered price of 10 €/(year×kW) [30] is used for this type of batteries in small or medium-size applications. In the feasibility analysis, the battery installed capacity values corresponding to 0 to 200 modules T-105 with a cost of 160 € per module were considered.

The power converter AC–DC allows charging batteries and transform direct current from the photovoltaic plant and the batteries to alternate current to cover the loads. The specific capital cost, replacement cost, and O&M cost of the converter were considered as 560 €/kW, 440 €/kW, and 5 €/(year×kW), respectively. The lifetime of the converter is 15 years, with an inverter efficiency of 90%, and the rectifier efficiency of 85%. For the feasibility analysis, it has been considered an installed power in the range of 20–200 kW.

2.3. Scenario Definition, Optimization Criteria, and Constraints

The optimization criterion is to reach the minimum of the net present cost (NPC) of the electricity for the considered application. The output NPC takes into account initial investment, the component replacement cost within the project lifetime, operation and maintenance cost, and fuel cost. For best solutions, HOMER software also provides the levelized cost of energy (COE) as the average cost of produced electricity (€/kWh) over the project lifetime.

To calculate COE, the concept of annualized cost (C_{ACAP}) of initial investment over the project lifetime must be considered, and it is defined by Equation (1) [35,36]:

$$C_{ACAP} = C_{CAP} \times CRF(i, N_{PROJ}) \tag{1}$$

where C_{CAP} is the initial capital cost of the component and $CRF(i, N_{PROJ})$ is the capital recovery factor (i = real interest rate, N_{PROJ} = project lifetime in years).

The capital recovery factor, CRF, calculates the present value of an annuity as described in Equation (2) [35,36]:

$$CRF(i, N_{PROJ}) = \frac{i \times (1+i)^N}{i \times (1+i)^N - 1} \tag{2}$$

where i is the real interest rate (a net interest rate after removing the effect of inflation) and N is the number of years.

For economic optimization, a project lifetime of 25 years and an annual real interest rate of 1% have been considered [37].

The constraints are conditions that must be satisfied, so HOMER only shows optimization or sensitivity results that comply with those constraints.

- Maximum annual capacity shortage (MACS) is the total capacity shortage (not covered energy demand, kWh) divided by the total annual electricity demand. No shortage has been considered, so it is 0%, as grid support is available in all cases.
- Minimum renewable fraction (MRF) is the percentage of the system's total energy production (which includes all sources of electricity as PV system or BGPP, and, also, electricity coming from the grid, considering it as a non-renewable source), which is really produced from renewable power sources. For sensitivity analysis, MRF has been considered as 0% (current situation), 20%, 50%, 70%, and 100%.
- Load following strategy: It has been considered that when the generator is needed, it produces just the power to meet the required demand (to cover consumer needs and, if necessary, to charge the battery).

The electricity prices for the university, according to the 2019 electricity supply contract, is based on 6 periods. Table 3 includes electricity rates of the university (including VAT) and Figure 5 shows the schedule of the six electricity rates.

Table 3. Electricity rates for the different periods.

Period	Power Price €/kWh	Demand Rate €/(kW·Month)
P1	0.15	4.148
P2	0.124	2.076
P3	0.113	1.519
P4	0.097	1.519
P5	0.092	1.519
P6	0.076	0.693

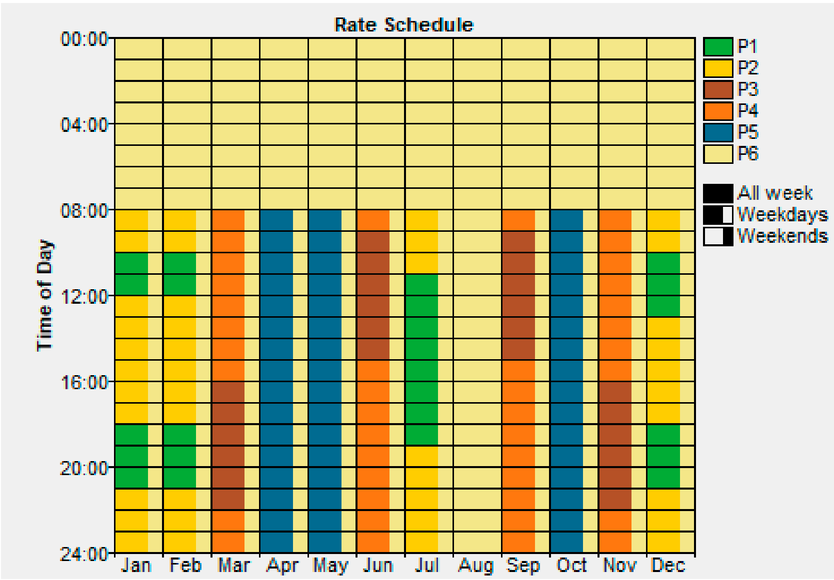

Figure 5. Schedule of electricity rates.

The contracted power for the present scenario (electricity purchase capacity) has been considered as 250 kW. Regarding electricity sales, a sell back price of 0.05 €/kWh has been considered [38], with the maximum sales capacity considered as 250 kW, and these prices have been approximated, taking into account average market prices in Spain, and national economic incentives for 2019.

3. Results

Current European energy policies present a target for 2030 of, at least, 27% share of renewable energy consumption (in terms of primary energy) and 45% of electricity production from renewable sources. Optimization results obtained in this work are focused on reaching a minimum contribution from renewable sources of 50% (called scenario MRF50) and 70% (called scenario MRF70) with minimum NPC. Main simulation results, considering a representative biomass cost as 150 €/t, have been included in Table 4. This table includes a simulation of the initial situation (electricity supply from the national electricity grid) for comparison purposes.

Regarding scenario MRF50, the best alternative (minimum NPC) is to install an 80-kW photovoltaic system (maximum installable power according to available roof area), in this case, MRF is 53% and COE is 0.111 €/kWh, lower than the initial situation, which presents a COE of 0.138 €/kWh. The MRF50 scenario does not include batteries or BGPP, and the typical operation profile is included in Figure 6. In this figure, weekdays (Monday to Friday) of periods without holidays have been selected, June has been selected as representative of the summer period, February for the winter period, and October as representative of the rest of the year (autumn and spring).

Scenario MRF70 requires additional renewable sources as biomass. biomass cost of 150 €/t has bee considered (using mixed agricultural–forestry biomass near Valencia city). The optimal hybrid system, from NPC point of view, corresponds to an installed power of 80 kW for PV, 40 kW for biomass (BGPP), and no batteries.

Table 4. The main simulation results comparing MRF50 and MRF70 scenarios to the utility grid.

Parameter	Utility Grid	MRF50	MRF70
AC primary load served (kWh/yr)	194,918	194,918	194,918
Photovoltaic plant (PV) production (kWh/yr)	-	134,878	134,878
BGPP production (kWh/yr)	-	0	84,855
Grid purchases (kWh/yr)	194,918	121,526	75,218
Biomass consumption (ton/year)	-	-	135.0
Maximum hourly grid purchases (kW)	201.2	132.9	92.9
Grid Sales (kWh/yr)	-	61,494	100,040
Cost of energy (COE) (€/kWh)	0.138	0.111	0.252

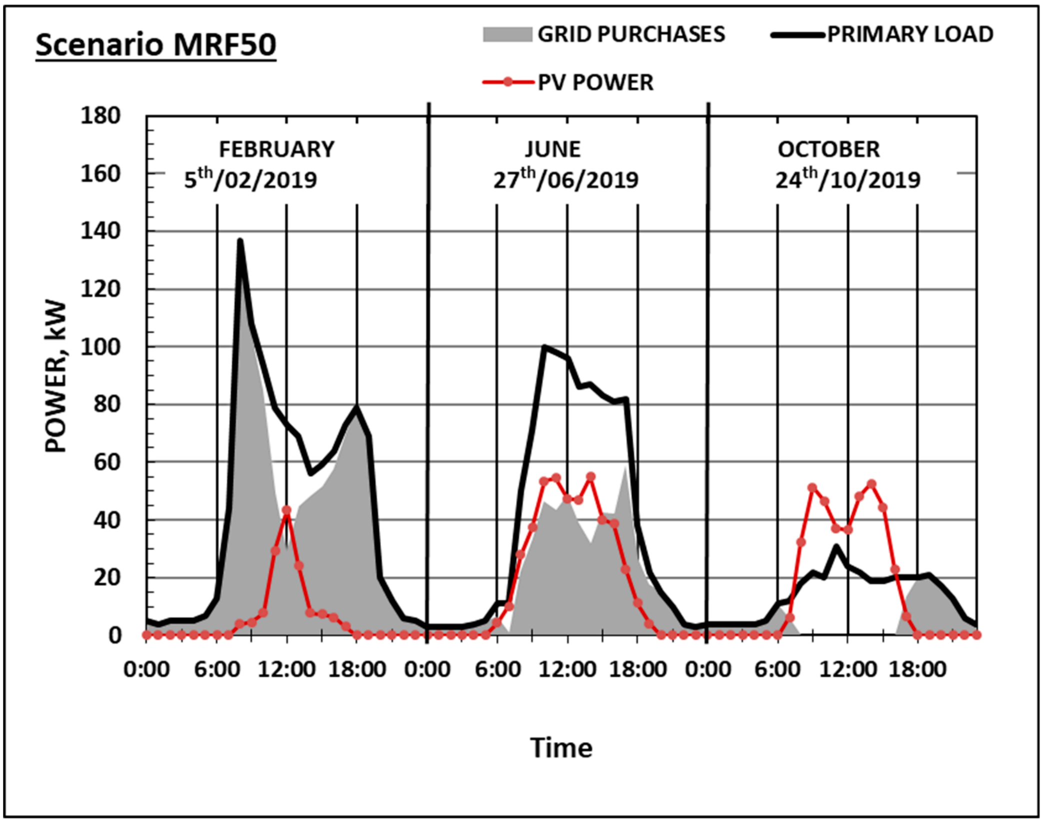

Figure 6. Optimized hybrid system for MRF50.

This figure shows the operation profile for a typical day in summer (27th June), winter (5th February), and the intermediate period (24th October). This system provides a minimum renewable fraction of electricity, MRF, of 74%, with a cost of electricity, COE, of 0.253 €/kWh. It must be noted that varying biomass costs from 150 €/t to 100 and 225 €/t would provide a COE of 0.215 and 0.305 €/kWh, respectively, so a high impact on COE due to biomass cost is observed despite electricity from BGPP (84.85 MWh/year) being 37% lower than PV production.

In the results, a sensitivity analysis has been performed by varying biomass costs and fixed renewable fractions (MRF) to evaluate the impact on the COE. The obtained comparative results have been included in the sensitivity analysis.

It is important to highlight that grid support needs (maximum power purchased from the grid) are only partially reduced (mainly due to winter period where peak power needs, early in the morning, are not so coupled with maximum renewable generation, and the photovoltaic contribution is lower than in summer period, see Figures 6 and 7).

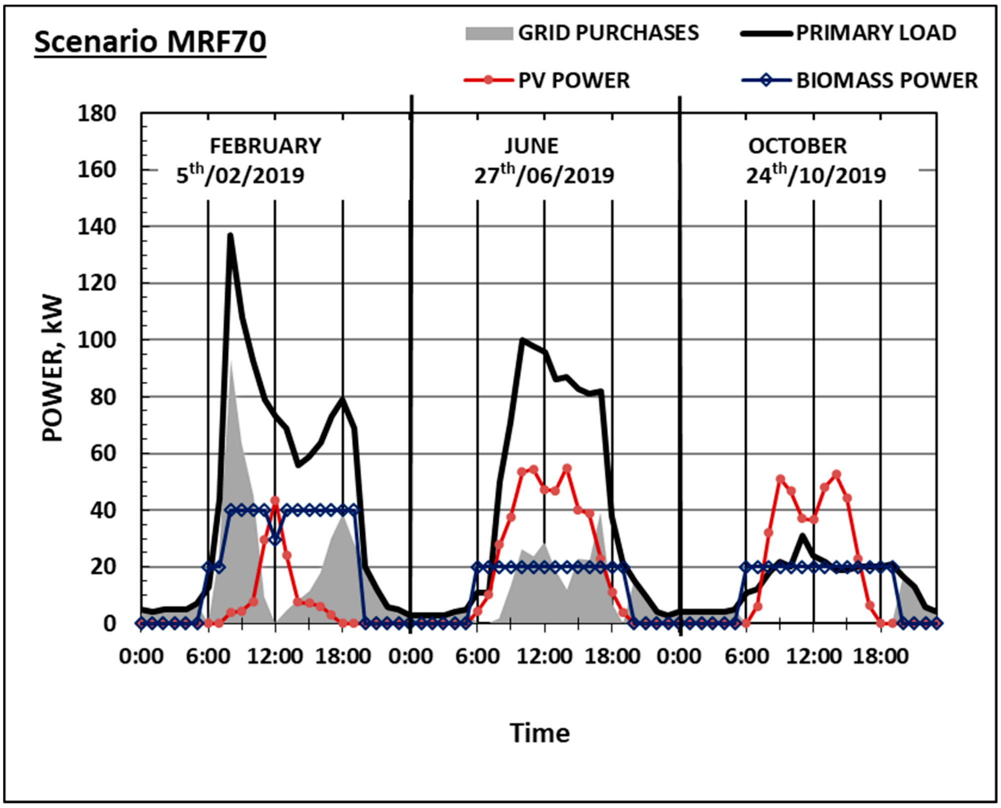

Figure 7. Optimized hybrid system for MRF70.

This is the most convenient option (from consumer economic point of view) but, from the electric utility standpoint, it would be better to reduce peak power needs in order to minimize reserve or stand-by power requests.

The cost of electricity varying the biomass cost and renewable fraction is analyzed. A high renewable fraction (higher than 80%) forces the system to cover peak power demand, so a combination of two strategies becomes necessary:

- The biomass plant (BGPP) must have higher installed power to cover short duration peak power needs, and equivalent operating time at rated power becomes lower, so amortization of the equipment is less favorable.
- The hybrid system needs higher storage (batteries) and AC–DC converter capacity.

Both strategies, together with limited maximum photovoltaic capacity due to roof availability, provide a very negative impact on economics. Figure 8 shows the impact on electricity cost due to the increment on renewable fraction and biomass cost. In order to facilitate the comparison between the different biomass costs considered, third order polynomial trendline has been generated (for values of renewable fraction higher than 53%) with good fitting (R-squared values for the three curves in the range 0.981–0.993).

Regarding sensitivity analysis, it is important to notice that biomass plant support becomes necessary when the minimum renewable fraction (MRF) is higher than 53%, and below this value, the optimal solution is based only on photovoltaics without batteries. This solution is especially interesting because, considering the limit of 53% of renewable fraction, COE would be 0.111 €/kWh, lower than the present scenario. It is also interesting to mention that without considering specific roof area restrictions of the selected building, and so considering bigger PV systems (a maximum simulated value of 320 kW, so four times the real installable power in the considered building), COE was always lower than the present situation until 85–90% of the renewable fraction with values of COE in the range 0.08–0.09 €/kWh.

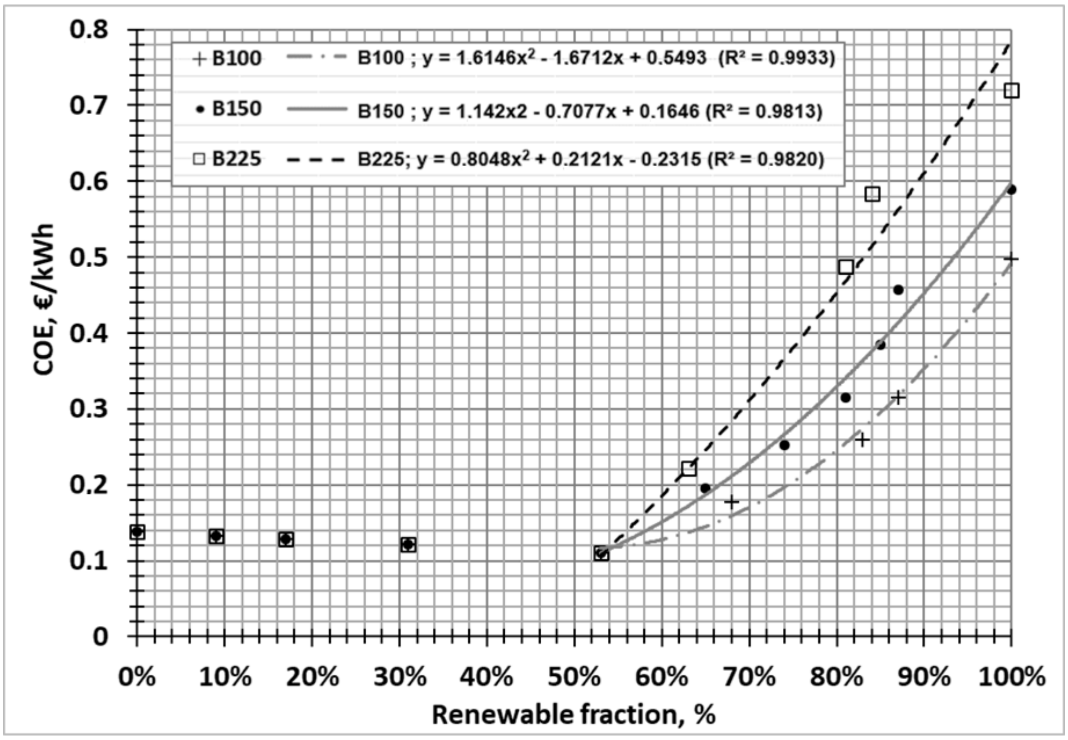

Figure 8. Cost of electricity (COE) according to renewable fraction and biomass cost.

4. Discussion

Economic modeling data for photovoltaic-biomass small size (<200 kW) hybrid systems using local biomass resources in a Mediterranean location (Valencia, Spain) have been provided. The technology used for biomass energy valorization is a bubbling fluid bed gasification plant, which has been modeled with real data obtained from experimental tests conducted at the IUIEE laboratories and, thereby, the real costs of the components, as well as the experimental efficiency at nominal and partial load, have been included in the simulations and shown in this document.

An optimization and feasibility analysis of such hybrid systems for a higher education building considering real hourly energy consumption data has been performed. Moreover, the real availability properties of nearby biomass resources (transport distance shorter than 35 km) and local solar radiation data are used for simulation purposes.

The results of the simulation indicate that the photovoltaic systems, without hybridization, but with flexible access to the grid (for electricity sales and purchases), are economically convenient since it presents 20% lower electricity costs (COE) than the present scenario. However, the limitation in the availability of the building´s roof area binds the renewable fraction (based only on photovoltaics) to 53%, approximately. A higher renewable fraction would require hybridization with another renewable source such as biomass.

Fixing the objective to 70% of the minimum renewable fraction, optimal hybrid systems deliver higher electricity prices than the present market (0.253 €/kWh), ranging from 0.215 to 0.305 €/kWh. Considering the realistic biomass (pellet from local sources) cost of 150 €/t, the renewable fraction can be 74% with a moderate electricity cost of 0.253 €/kWh (including annualized initial capital cost, annualized replacement cost, annual O&M cost, annual fuel cost, and cost of electricity purchased from the grid).

The main impact in the cost of electricity derives from the minimum renewable fraction established and roof area limitation; over 55–60% MRF implies a significant increment in the cost per kWh. This is because the peak power demand needs to be covered by hybrid systems; therefore, additional renewable sources as biomass is required. Additionally, in the range of 75–100% MRF, energy storage becomes necessary, and COE increases exponentially from 0.28 €/kWh to 0.59 €/kWh (for a biomass cost of 150 €/t).

It can be concluded that PV systems present high economic feasibility, but due to possible roof area limitations, other sources are needed. In this situation, biomass can be considered as an alternative source together with PV, providing higher renewable contribution, but with significantly higher COE.

Author Contributions: Conceptualization, D.A.-S. and C.V.-S.; methodology, D.A.-S. and E.H.-P.; software, D.A.-S.; validation, D.A.-S., C.S.-D. and E.H.-P.; formal analysis, D.A.-S. and C.V.-S.; investigation, D.A.-S., C.S.-D. and E.H.-P.; resources, D.A.-S. and C.S.-D.; data curation, D.A.-S. and C.V.-S.; writing—original draft preparation, D.A.-S., C.V.-S., and C.S.-D.; writing—review and editing, D.A.-S., C.V.-S., and C.S.-D.; visualization, D.A.-S. and C.V.-S.; supervision, E.H.-P.; project administration, E.H.-P.; funding acquisition, C.S.-D. All authors have read and agreed to the published version of the manuscript.

Funding: This work was supported in part by the European Commission through project "Holistic And Scalable Solution For Research, Innovation And Education In Energy Tran project" (Agreement number: 837854). This work was supported in part by the European Commission through GROW GREEN project (Agreement number: 730283 — GROW GREEN — H2020-SCC-2016-2017/H2020-SCC-NBS-2stage-2016. http://growgreenproject.eu/).

Acknowledgments: This work was completed in the framework of the activities of the Renewable Area research group of the IUIIE (Instituto Universitario de Investigación en Ingeniería Energética) in regional, national, and international projects. The authors deeply thank the Universitat Politècnica de València, IMPIVA-Generalitat Valenciana, the Spanish Ministry of Science and Technology, and the European Commission for the funded projects coming from this organization.

Conflicts of Interest: The authors declare no conflict of interest.

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