Thermo-economic and environmental analysis of integrating renewable energy sources in a district heating and cooling network

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Abstract

This paper presents the technical, environmental and economic evaluation of integrating various combinations of renewable energy sources-based systems in the expansion of a district heating and cooling network of a Technology Park near Barcelona in Spain. At present, a Combined Heat and Power plant running on fossil fuels serves the heating, cooling and electricity demand of the Park. However, this energy demand is expected to increase substantially in the coming years. EnergyPRO software was used to model the energy demand growth till 2030. Validation of the software application was done by making a base model using real plant data from the year 2014. The software was then used to project the energy supply based on three 15-year scenarios, having different combinations of renewable energy technologies, from 2016 until 2030. Primary energy consumption, CO_2 emissions and the Net Present Value obtained in each scenario were used to decide the best combinations of renewable energy sources. The results of the study showed that presently, biomass boilers combined with absorption chillers and supported with solar thermal cooling, are the most competitive technologies in comparison to ground source heat pumps for large DHC networks. This is mainly because of the lower primary energy consumption (624,380 MWh/year in 2030 vs. 665,367 MWh/year), higher Net Present Value (NPV) (222 million € vs. 178 million €), and lower CO_2 emissions (107,753 tons/year in 2030 vs. 111,166 tons/year) obtained as a result of the simulations.

Keywords: District heating and cooling, renewable energy integration, energy efficiency, feasibility study, techno economic evaluation

Nomenclature

Greek Letters

η_{el}	Electrical efficiency (%)
η_{th}	Thermal efficiency (%)

Subscripts

c	Cooling
h	Heating
th	Thermal
el	Electric

Acronyms

BAU	Business As Usual	GSHPs	Ground Source Heat Pumps
CAPEX	Capital Expenditure	IT	Information Technology
CHP	Combined Heat and Power	KPIs	Key Performance Indicators
CO_2	Carbon dioxide	NZEBs	Net Zero Energy Buildings
COP	Coefficient of Performance	P & L	Profit and Loss
DH	District Heating	PEF	Primary Energy Factor
DHC	District Heating and Cooling	PTCs	Parabolic Trough Collectors
EBITDA	Earnings Before Interests, Taxes Depreciation and Amortization	RES	Renewable Energy Sources
EU	European Union	SCBC	Solar cooling and biomass cooling
GHG	Green House Gas	TES	Thermal Energy Storage

1. Introduction

The increase in price of fossil fuels, their rapid depletion and environmental impact have accelerated research work in Renewable Energy Sources (RES) and thus RES are playing an important role in future energy systems. Moreover, fossil fuels are a major contribution to greenhouse gas (GHG) emissions, due to which several countries and international bodies are setting immediate goals to combat climate change. The European Union (EU) for instance, has set the ambitious target of having at least 27 % share for renewable energy in its total energy mix by 2030, as per the 2030 climate and energy framework [1].

Along with an increased push in using renewables, it must be mentioned that buildings account for 40% of energy usage and CO_2 emissions in the EU [2]. To mitigate the contribution of energy sector to climate change, several policies have been designed and implemented, which supports the development of high-efficiency Combined Heat and Power (CHP) plants in Europe [3]. CHP plants are not only energy efficient, but may also curb CO_2 emissions if powered by RES based systems. Thus, to help the EU meet its ambitious targets, integration of RES in District Heating and Cooling (DHC) networks appears to be an excellent solution.

Several studies have been carried out for evaluating the technical, economic and environmental feasibility of integrating RES in DHC networks. Dagdougui et al. [4] developed a dynamic model to integrate different RES and a storage device to satisfy the thermal and electric demand of a “Green Building”. Wang et al. [5] used a modelling and optimizing technique for developing CHP based District Heating (DH) system, with a solar thermal plant and Thermal Energy Storage (TES) system. Results of the analysis proved that the model is suitable for planning and running CHP-DH systems economically. A simulation was then run with higher proportion of RES and a larger TES, indicating that the TES is utilized more with higher share of RES and a fluctuating load of the CHP-DH system. Østergaard [6] , using the EnergyPRO software, developed a 100% renewable energy scenario for the Danish city of Aalborg and then compared the overall impact on the system of various energy storage systems (DH storage, biogas storage and electricity storage). Nielsen and Moller [7] carried out a study for Denmark where they modelled the integration of solar thermal collectors into Net Zero Energy Buildings (NZEBs) connected to district heating (DH) networks, so that the collectors could satisfy part of the heating demand. The results show that the NZEBs experienced a net decrease in heat supply from the network (CHP units and boilers), and hence decrease in burning of fuels. Streckiene et al. [8] modelled the optimum CHP plant with thermal energy storage that would be most suitable to take advantage of the day ahead German electricity market. The results of the study showed that for a CHP plant supplying 30,000 $MWh_{th,h}$ thermal energy annually, a $4MW_e$ capacity plant with a thermal store would be most technically and economically feasible for participating in the spot market. For district heating systems in Lithuania, Lund et al. [9] did a study where they analysed the replacement of old boilers burning fossil fuels with CHP units running on renewable sources such as wood. Results showed that this would considerably decrease fossil fuel consumption by 50-70% and CO_2 emissions by 50% or 70% (depending upon the scenario), and also bring down the district heating prices in small towns to the level of those in urban areas. Thermo economic analysis have been performed of district heating and cooling systems connected to ground source heat pumps (GSHPs) in [10], [11], [12] and [13]. Carli et al. [11] showed that in comparison to traditional heat pumps, using GSHPs can reduce primary energy consumption between 50 and 80%. Similar studies, utilizing exergy methods, have been carried out for geothermal district heating systems in [14] and [15]. An interesting thermo economic optimization was performed by Baghernejad et al. [16] of a solar assisted trigeneration (cooling, heating and electricity) system. An optimization model was developed by Buoro et al. [17] for a solar thermal system (with heat storage) integrated with a CHP plant. The study showed that the most economic and environmental friendly scenario is one where the solar field, thermal storage and district heating network operate together. Torchio [18] did an analysis to compare district heating CHP with distributed generation (on-site) CHP. Of the three technologies used for the analysis, fuel cells, micro turbines and internal combustion engines, the results showed that the lowest amount of carbon dioxide emissions was obtained when fuel cells are used as the CHP units in a district heating network. Soltero et al. [19] did a study to replace existing individual heating systems and old coal and nuclear power stations in the Spanish city of Burgos with CHP district heating. Results showed that with this replacement, annually 4 million tons of CO_2 emissions could be avoided and profits of 300 million € could be made. Kazagic et al. [20] did a feasibility study for the city of Visoko where they proposed a renewable energy based DH system to replace the current coal fired CHP plants. Although the investment costs were higher for the renewable energy based system, the fuel costs and CO_2 emissions were 58% and 46% less respectively than that of the coal based system. Rämä et al. [21] did a feasibility study for the city of Helsinki in Finland where they modelled an increased the share of renewable heat sources (solar thermal collectors and water-to-water heat pumps) in the existing DH system. Results showed that heat pumps are a better option when compared to solar collectors, not only in terms of environmental emissions but also cost effectiveness.

Despite a large number of publications available on the topic, there is lack of a complete feasibility study i.e., technical, economic and environmental analysis on the establishment of

RES based DHC in a Mediterranean climatic zone in Spain. This may be perhaps because there is generally a lack of regulations for DHC networks in Spain [22]. It is challenging to attract investors for setting up new DHC networks because of the long term amortization, lack of funding from banks and low public investment. Moreover, for cultural and societal reasons, cooling and heating customers prefer individual domestic systems in comparison to collective DHC systems.

This article aims to form a basis for promoting DHC networks based on RES. It presents the technical, environmental and economic evaluation of integrating RES for the expansion of an existing DHC system in Parc de l' Alba, a Technology Park near Barcelona in Spain. The reason for choosing this specific location is the fact that it lies in the region of Catalonia in north east Spain, next to the Mediterranean Sea and bordering France at the Pyrenees mountains. Thus, the region has a variety of different climatic zones, making it a suitable location to establish DHC networks.

Currently, a CHP plant, titled ST-4, serves the demand of cooling, heating and electricity of the non-residential consumers but there is a forecast of increased demand over the years. An energy model is created initially and validated, after which the demand growth is modeled. Three 15-years projection scenarios are created incorporating different combinations of RES. The best combinations of RES are decided based on the CO_2 emissions, primary energy consumption and Net Present Value (NPV), which have been considered as the Key Performance Indicators (KPIs).

2. Material and Methods

The detailed layout of the methodology is shown in Figure 1. The very first step, as explained previously, was creation of base model in 2015 to ensure that future analysis of scenarios would be accurate. Real data from the plant (for year 2014) were obtained and provided to EnergyPRO [23] software, which is the primary software tool used for calculations in this study. Based on several inputs including demand profile, weather data, tariffs, efficiencies and capacities of energy conversion units, EnergyPRO gives a comprehensive output on economics, emissions and operational strategy.

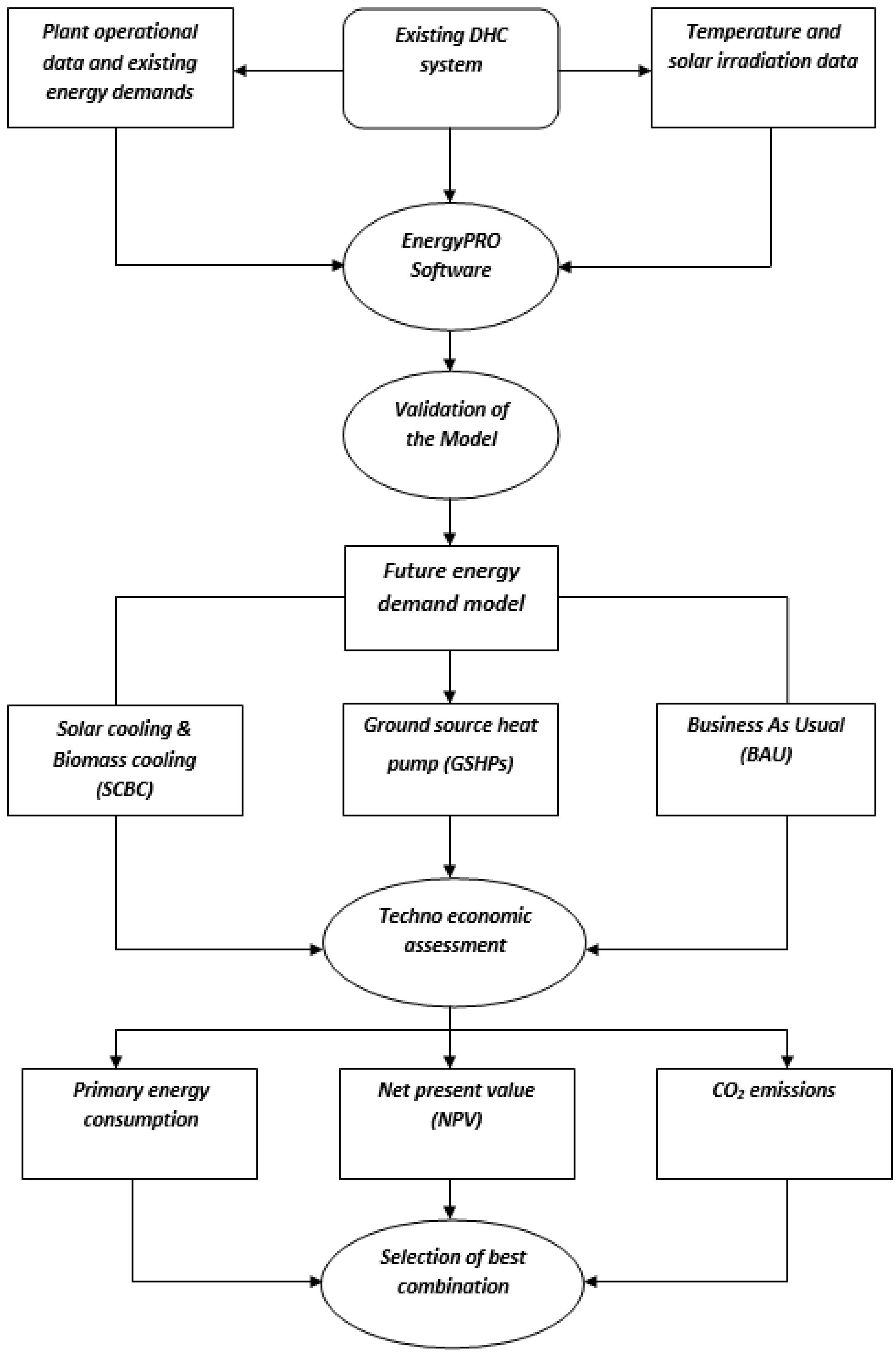

Figure 1: Methodology of the feasibility study

The initial inputs to the base model were Time Series of hourly temperature data and solar irradiation of Barcelona. These climate time series were obtained from an online database. To generate the electricity market of Spain [24] , the following time series were provided as input:

- **Pool Price (TS1)** It denotes pool price for the year, continuously varying on hourly basis between 0 €/MWh$_e$ and 114 €/MWh$_e$ for the year 2016
- **57€/MWhe (TS3)** Time series with a constant value of 57 €/MWh$_e$ in 2016. According to Spanish legislation, it corresponds to the payment for system operation
- **Spanish Tariff Hours (STH)** It denotes fraction of electricity price dependent on different time periods of the day when buying from the grid. Varying on hourly basis between 7.0 €/MWh$_e$ and 27.9 €/MWh$_e$ for the year 2016

Three Time Series Functions were utilized to compute costs and revenue related to electricity export and import. They are:

- **Price Electricity Imported Time Series (STHF)** Addition of two time Series, STH and TS1, denoting the amount of money paid by ST-4 if electricity is purchased from the grid. It is defined by equation (1)

$$STHF = STH + TS1 \tag{1}$$

- **Price Electricity Exported Time Series (Fu1)** Addition of two time series, TS3 and TS1, denoting the amount of money ST-4 earns when electricity is exported to the grid. It is defined by equation (2).

$$Fu1 = TS3 + TS1 \tag{2}$$

- **Exported Electricity Tax (Fu2)** It denotes the tax paid on 7% of the electricity exported to the grid. It is defined by equation (3).

$$Fu2 = Fu1 * 0.07 \tag{3}$$

Currently, natural gas is burnt in the engines that produce electricity and heat. This heat is sent to the district heating network and is fed to the two absorption chillers to produce cooling for the district cooling network. Excess cooling is stored in the cold-water storage tank. The cooling tower ensures removal of any excess heat from the engines. When electricity prices are low, the engines are turned off. The natural gas boiler and compression chiller serves the heating and cooling demand respectively; the cold-water storage tank is also discharged in case the compression chiller is not enough. Key details of all energy conversion units and cold storage tank at the ST-4 plant are shown in Table 1. The operating scheme of the plant is shown in Figure 2. It is assumed that the electrical and/or thermal energy conversion efficiencies of the different energy conversion units remains the same even at part load operation.

Table 1: Details of ST-4 plant at Parc de l'Alba (2015)

Unit type	**Quantity**	**Specifications (each unit)**	**Comments**
Cogeneration Engines	3	3.28 $MW_{th,h}$; 3.35 MW_e; η_{el} = 44.9%; η_{th} = 41.1 %	Turned on together whenever electricity spot markets are high
Single Effect Absorption Chiller	1	3 $MW_{th,c}$; COP = 0.7	Driven by hot water from the engines at 90 ºC
Double Effect Absorption Chiller	1	5 $MW_{th,c}$; COP = 1.3	Driven by exhaust gases of the engines at 398 ºC
Natural gas boiler	1	5 $MW_{th,h}$; η_{th} = 60%	Back-up
Compression Chiller	1	5 $MW_{th,c}$; COP = 5	Back-up
Cold water storage tank	1	4000 m^3; 21 $MWh_{th,c}$	
Total plant capacity (excluding backup): 8.0 $MW_{th,c}$, 9.8$MW_{th,h}$ and 10.1 MW_e			

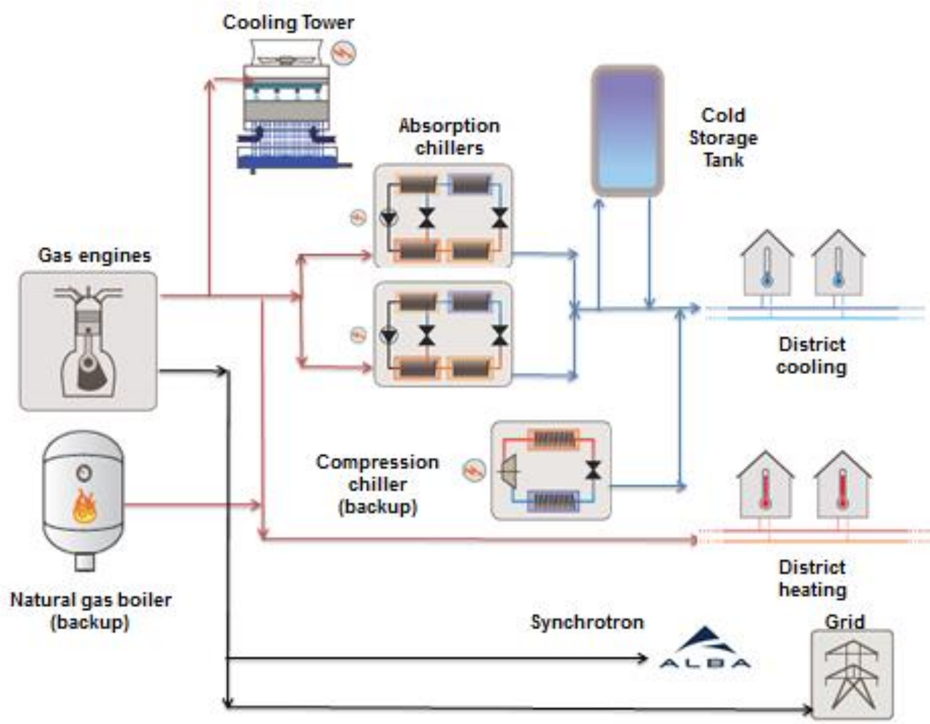

Figure 2: Current operational scheme of ST-4 plant at Parc de l'Alba

The fuel used is natural gas, so it is input to the model with a calorific value of 10.64 kWh/m^3[25]. In 2015, the ST-4 plant serves energy demands of the Synchrotron (particle accelerator) facilities and an office building (called “Plot 1” in the scope of this study for reasons of not disclosing the actual name of the client), details of which are shown in Table 2. It needs to be mentioned here that the different demand profiles for the various consumers are not considered for the ones in 2015, but have been taken into account for analysis of future scenarios.

Table 2: Annual energy demands served by ST-4 in 2015

Type of demand	Consumer	Value
Cooling demand	Synchrotron	21,700 $MWh_{th,c}$
	Plot 1	651 $MWh_{th,c}$
Heating demand	Synchrotron	900 $MWh_{th,h}$
	Plot 1	530 $MWh_{th,h}$
Electricity demand	Synchrotron	20,400 MWh_e
	In-house consumption and losses	5,320 MWh_e

The plant generates income not only by selling heating and cooling, but also by selling electricity to the Synchrotron and grid. The Appendix shows details of the revenues, along with the plant expenses, as obtained from the Parc de l' Alba management [25].

After providing all the afore mentioned inputs, the simulation was run. The model optimizes plant operation according to the electricity pool prices and electricity production costs. Data was obtained for an entire year from the simulation in hourly basis, and validated against actual results. Table 3 shows the comparison between the actual figures obtained from the plant and the simulation results, for the year 2015 for the months of January, February and July-December. In the months of March-June, the compression chiller had broken down and the resulting change in plant operation was not taken into account by the software. Hence, comparison between simulation and real data for these months is not presented.

Table 3: Comparison of actual plant operational data of Parc de l' Alba compared against results of the EnergyPRO simulation for selected months of year 2015 (all months of the year excluding March-June)

Parameter	Actual data	Simulation results	Percentage difference
Cooling demand	20,500 $MWh_{th,c}$	22,400 $MWh_{th,c}$	-9%
Heating demand	1,430 $MWh_{th,h}$	1,430 $MWh_{th,h}$	0%
Electricity demand	25,700 MWh_e	25,700 MWh_e	0%
Electricity production by gas engines	35,600 MWh_e	36,900 MWh_e	-4%
Exported electricity	21,900 MWh_e	25,900 MWh_e	-18%
Imported electricity	12,100 MWh_e	16,400 MWh_e	-36%
Net electricity export	9,800 MWh_e	9,500 MWh_e	3%
Natural Gas Boiler Fuel consumption	1,950 $MWh_{th,h}$	1,500 $MWh_{th,h}$	24%
Natural Gas Boiler Heat production	1,170 $MWh_{th,h}$	890 $MWh_{th,h}$	24%
Duration of operation of gas engines	3,600 hours	3,700 hours	-3%

Although the simulation results of imported, exported and net exported electricity show a considerable difference from the actual data, it can be deduced that the software is reliable for estimation of future scenarios. This is because the electricity markets of Spain are extremely complex and cannot be very precisely modelled by EnergyPRO.

Next, EnergyPRO models were created for the years in which new demands were incorporated, namely 2016, 2017, 2018, 2020, 2025 and 2030. New demands in the corresponding years were inserted into the models, according to the forecast provided by Parc de l’ Alba management. In case of the years for which simulations were not performed (2019, 2021-2024 and 2026-2029), it was assumed that the energy performance of the DHC plant(s) remains the same as preceding simulation year (energy performance of 2019 is identical to 2018, that of 2021 till 2024 is identical to 2020, while that of 2026 till 2029 is identical to 2025). Since EnergyPRO does not have the capability to dimension the distribution network , LOGSTOR calculator [26] was used for calculating the thermal losses for each year in the different scenarios. The information provided to LOGSTOR is shown in the appendix.

It was found that the existing plant is enough to satisfy the demand of 2016. However, in 2017, cooling and heating demands increased by 1768 $MWh_{th,c}$ and 960 $MWh_{th,h}$, and thus new energy conversion technologies were implemented henceforth. For the future years, different combinations of RES were used to satisfy the demand, as explained before. The best combinations were decided based on the primary energy consumption, CO_2 emissions and NPV.

When comparing different fuel types, primary energy consumption is a preferable metric since it considers the energy required to produce one unit of a consumed particular energy on site; including transportation, storage, distribution, delivery and any losses incurred in the process. CO_2 emissions were chosen for evaluating environmental feasibility since they contribute the most to climate change. The primary energy consumption and CO_2 emissions in each scenario were calculated by simply multiplying the specific emissions factors and Primary Energy Factors (PEFs) respectively of each fuel with the total respective fuel consumption in that scenario. Table 4 shows the PEFs and CO_2 emission factors of fuels used in various scenarios taken from [27].These values were assumed to be unchanged for the future years in all scenarios. It should be mentioned here that the low specific emission factors for biogas and biomass might be considered controversial [28]. Even though combustion of biofuels emits carbon that is part of the biogenic carbon cycle, studies and analysis do not always take into account how long does it take for this carbon to return to the biogenic pool from the atmosphere.

Table 4: Primary Energy Factors and Specific emissions factors for fuels used in Parc de l' Alba

Fuel	Primary Energy Factor	Specific emission factor (kg CO_2/unit fuel)
Imported Electricity	2.37	0.36 kg/kWh
Natural gas	1.20	2.68 kg/m^3
Biogas	0.50	0.62 kg/m^3
Biomass	0.03	0.06 kg/kg

For economic feasibility, NPV is chosen as the primary indicator, since it takes into account the time value of money for each scenario, thus showing how profitable was one scenario when compared to another. For this purpose, comprehensive economic calculations are performed by creating Profit and Loss (P & L) sheets for each scenario, starting from the present (2016) , up to the end of the concession period (2047). The procedure followed is outlined in detail by Ross et al. [29]. The NPV, assuming an interest rate of 10 %, keeping lifetime of the investment at 31 years (with 2016 as year 'zero') is calculated by equation (4). The interest rate of 10 % was chosen based on the author`s experience of conducting economic feasibilities of similar projects.

$$NPV = -C_0 + \sum_{t=1}^{T} \frac{C_t}{(1+i)^t} \tag{4}$$

Here, C_0 is the free cash flow in year zero (in €), T is the lifetime of investment (in years), C_t is the free cash flow in year 't' (in €), 'i' is the interest rate (in %) and t represents the time of cash flow (in years). Once the EnergyPRO simulations have provided the revenues and operating expenditures, The Free Cash Flow is obtained by solving several equations in a sequential manner as outlined in [29]. Equation (5) shows how the free cash flow is obtained.

$$Free\ cash\ flow = Operating\ Cash\ Flow - Increase\ in\ Working\ capital - CAPEX \tag{5}$$

The Capital Expenditure (CAPEX) refers to the purchases/investments made in each scenario whenever new energy conversion units are introduced, the investment varying as per the technologies being used in the scenario. An inflation of 7.48% was applied to natural gas prices and the variable and fixed prices of heating and cooling ; this value is basically the percentage by which gas prices have increased in Spain in the past 13 years according to IEA [30]. Similarly, electricity prices in Spain have increased by 9.72 % per year on average from 1980 till 2012 and this was the inflation applied to variable price of electricity. An inflation of 2 % is assumed for all other costs and revenues [31].

3. Demand modeling

The energy demand growth can be seen graphically in Figure 2 and Figure 3 . Future energy demands were provided by the Parc de l' Alba management.

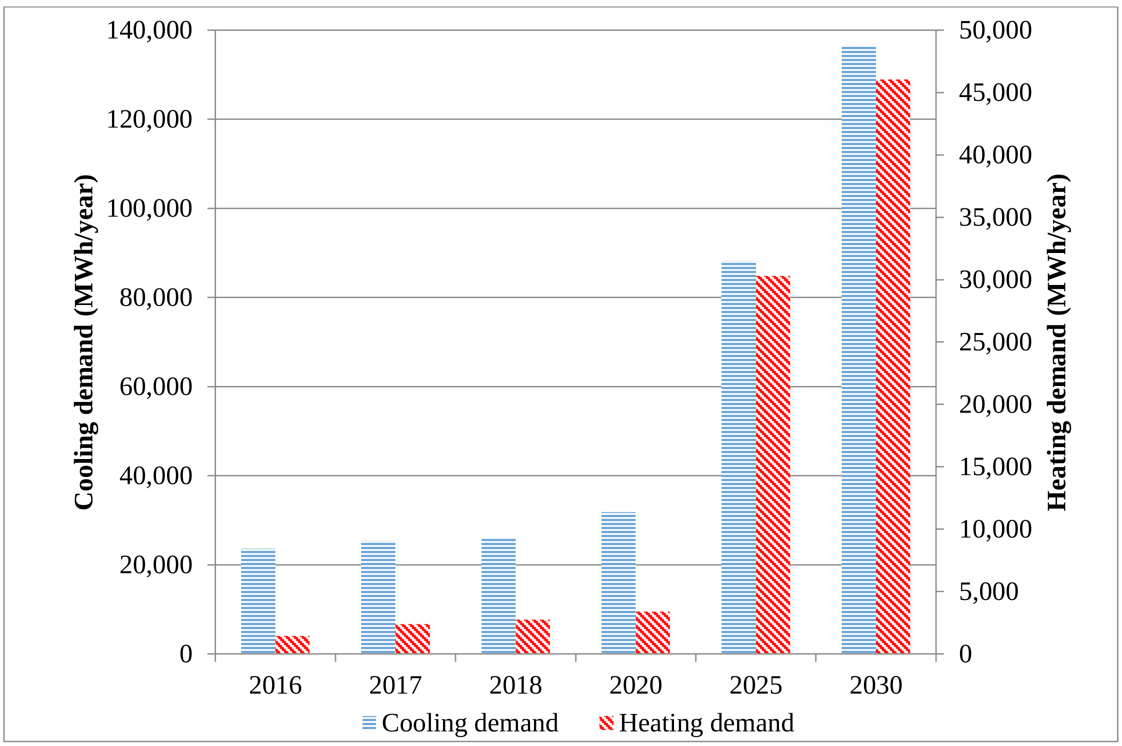

Figure 2 Cooling and heating demand projection of Parc de l' Alba till 2030

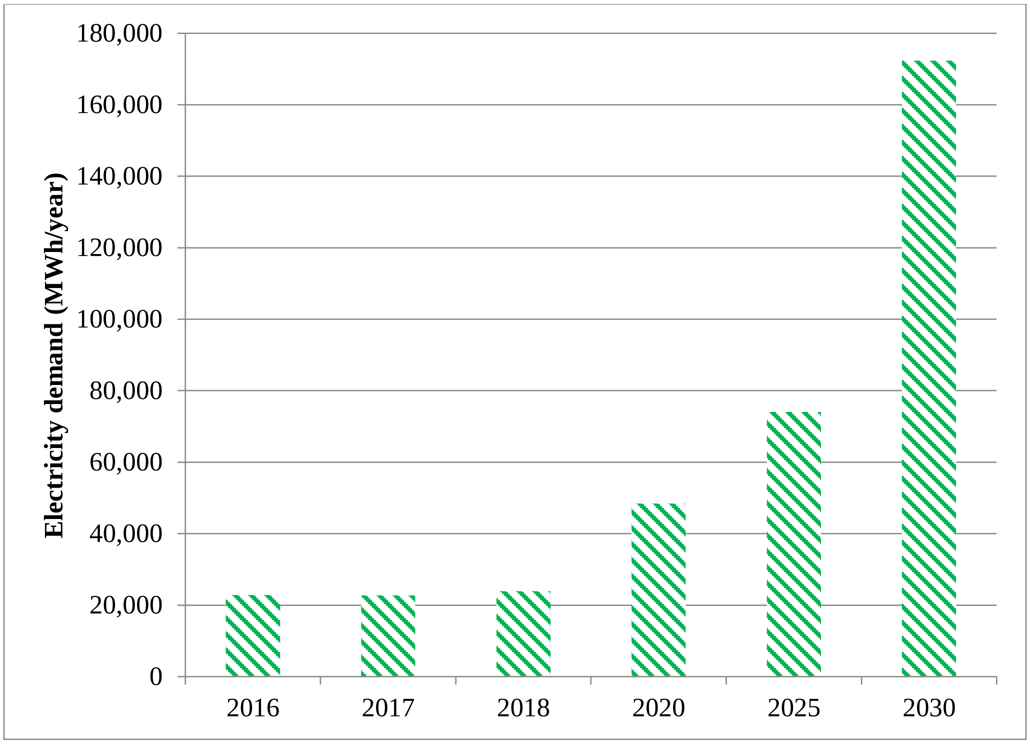

Figure 3 Electricity demand projection of Parc de l’ Alba till 2030

The transmission and distribution losses for the cooling and heating lines for Parc de l’ Alba are shown graphically in Figure 4. It is clear that the heating losses are greater than the cooling losses, indicating that the lines for DH are oversized, in comparison to those for DC.

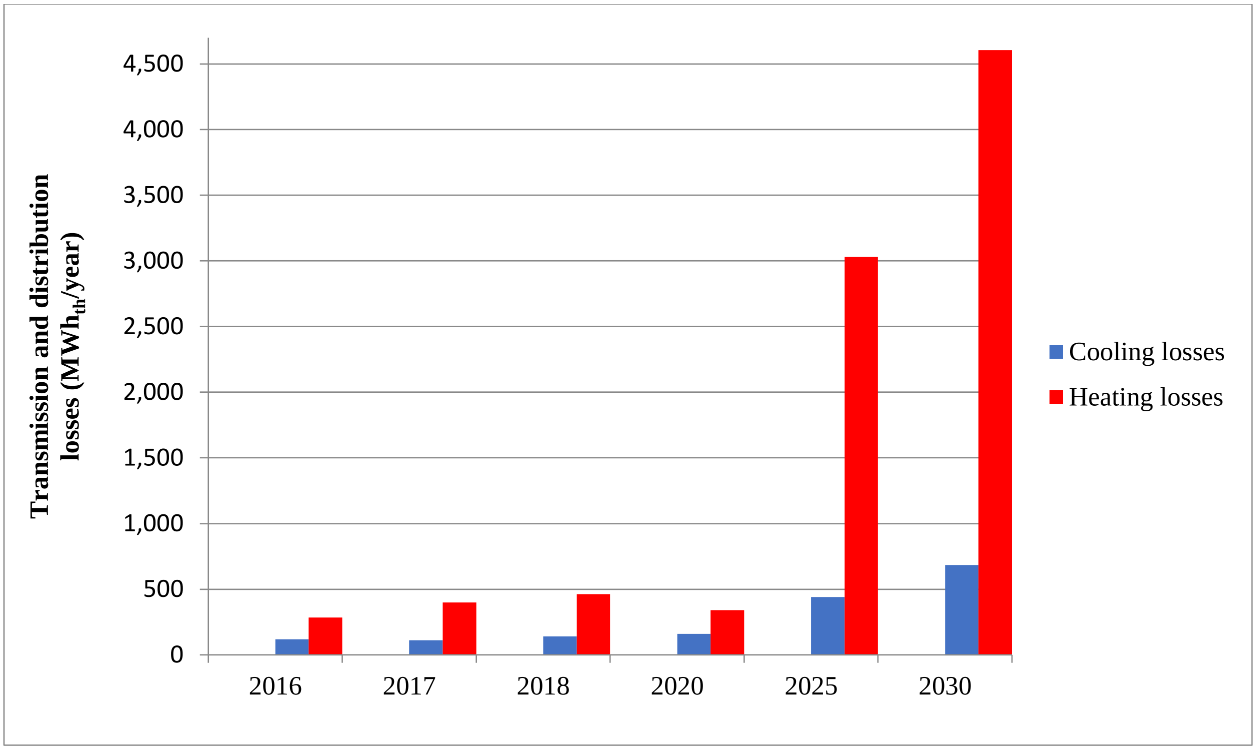

Figure 4 Transmission and distribution losses of heating and cooling in Parc de l' Alba till 2030

The different consumers in Parc de l’ Alba are the Synchrotron particle accelerator (cooling and electricity), offices (cooling, heating and electricity) and data centers (cooling and electricity). Details of the energy demand growth are shown in the Appendix in tabular form. All energy demands for the various consumers were inserted as a Time Series for each year. The Synchrotron has a periodic operation throughout the year and hence its cooling and electricity demands were modeled according to the data received from Parc de l’ Alba. In the first half of the month of January, the full month of August and second half of December, the Synchrotron itself does not require cooling but its offices do, having a peak demand of 1.3 $MW_{th,c}$. For rest of the year, it operates in cycles: it is in operation for four consecutive weeks (peak demand of 3.3 $MW_{th,c}$) and out of operation for a week (only its offices require cooling with a peak demand of 1.3 $MW_{th,c}$). The electricity demand follows a similar behavior to the cooling demand, the main difference being that the electricity demand is expected to increase by five per cent after 2017; this is input on the software by increasing the peak value of electricity consumption when the Synchrotron is in operation. Figure 5 and Figure 6 show the annual cooling and electricity demand profiles respectively of the Synchrotron

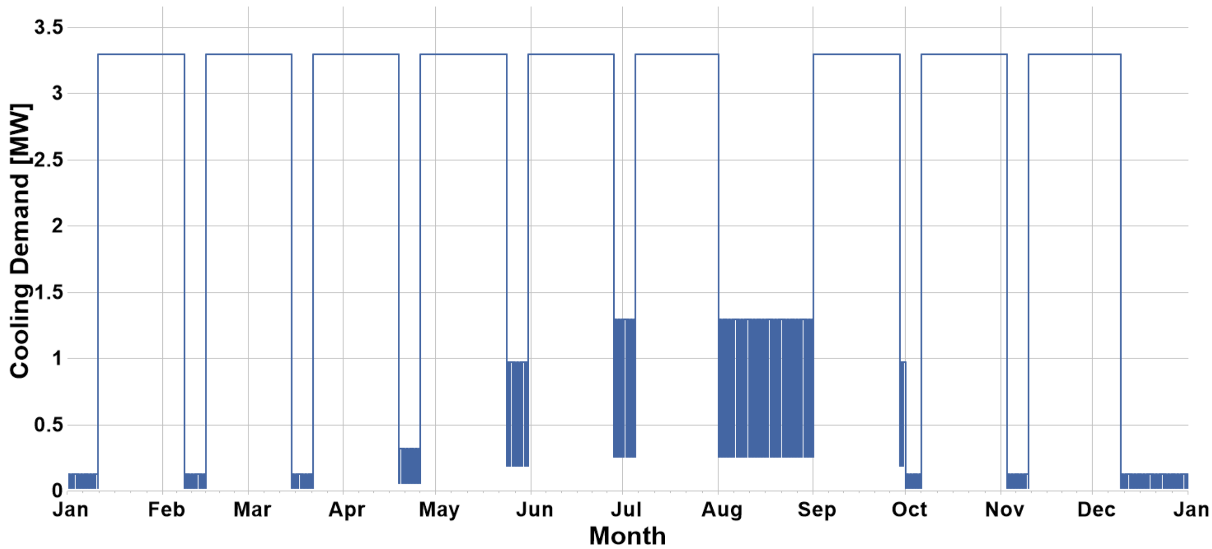

Figure 5: Annual cooling demand profile of Synchrotron facilities

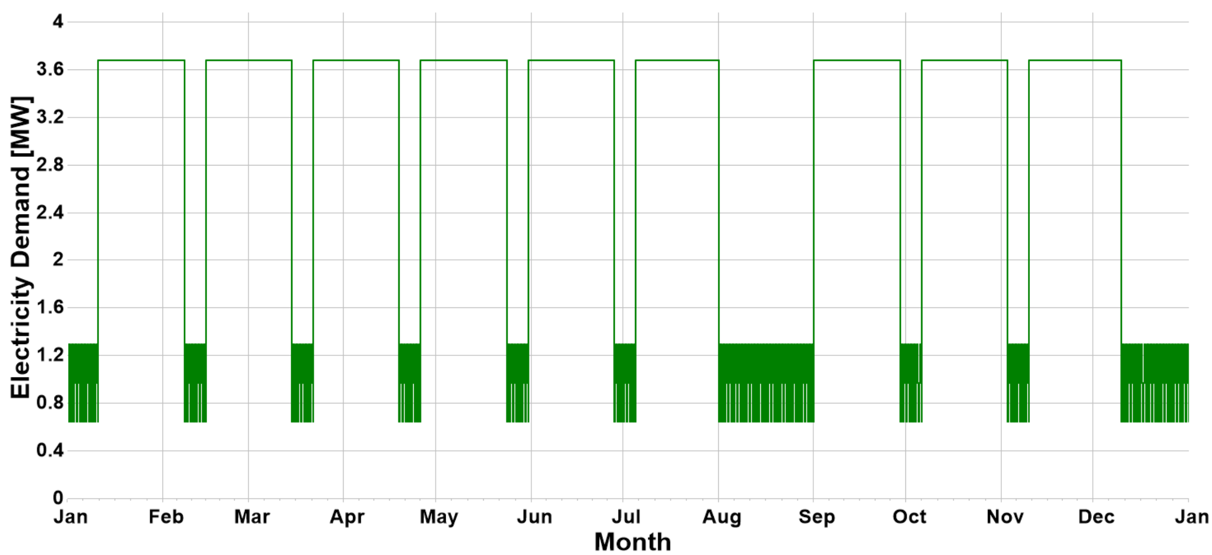

Figure 6: Annual electricity demand profile of Synchrotron facilities

A notable difference is there between the demand profiles in Figure 5 and Figure 6; this is because electricity demand is not dependent upon ambient conditions and has the same profile throughout the year.

For offices, the cooling and heating demands were modeled according to [32] and [33]. The main assumptions for the cooling demand are:

- 45-52% of the total demand is linearly dependent on the ambient temperature ; it will start when ambient temperature exceeds 18°C

- The cooling demand has a fixed profile throughout the year , i.e., 100 % cooling from 6 AM to 8 PM from Mondays to Fridays and 20% at all other times

For heating demand, the main assumptions are:

- 3% of the demand is allocated to Domestic Hot Water , which is provided throughout the year at all times

- 97% of the demand is linearly dependent on the ambient temperature ; it will be provided when the ambient temperature is below 18°C

- The heating demand has a fixed profile throughout the year, i.e., 100% heating from 6AM to 8PM from Mondays to Fridays and 25% at all other times

Figure 7 and Figure 8 show examples of the annual cooling and heating demand profiles of the offices.

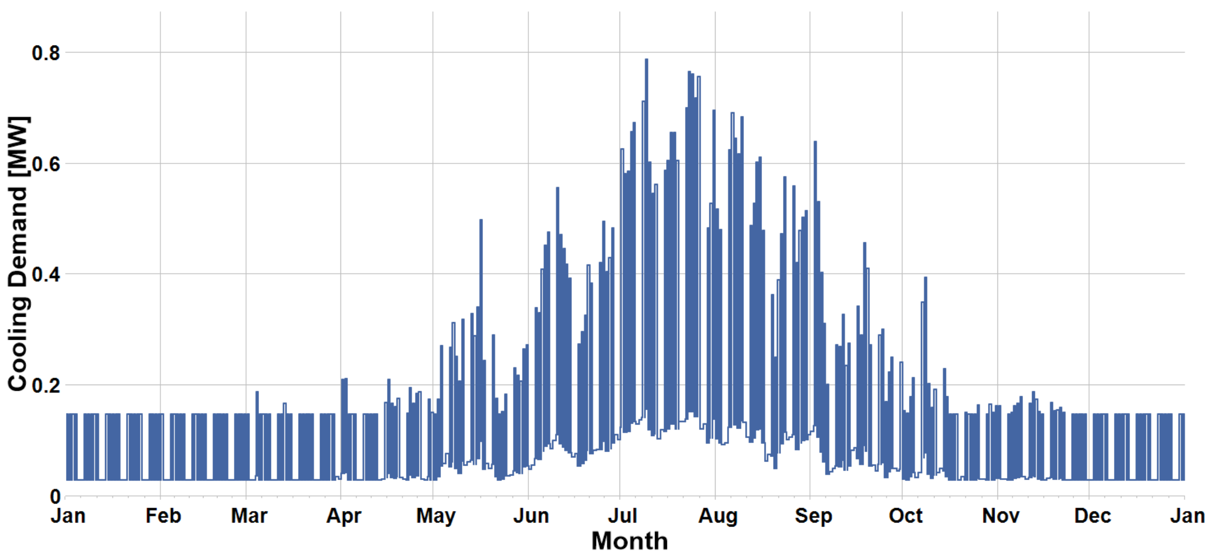

Figure 7: Annual cooling demand profile of office buildings

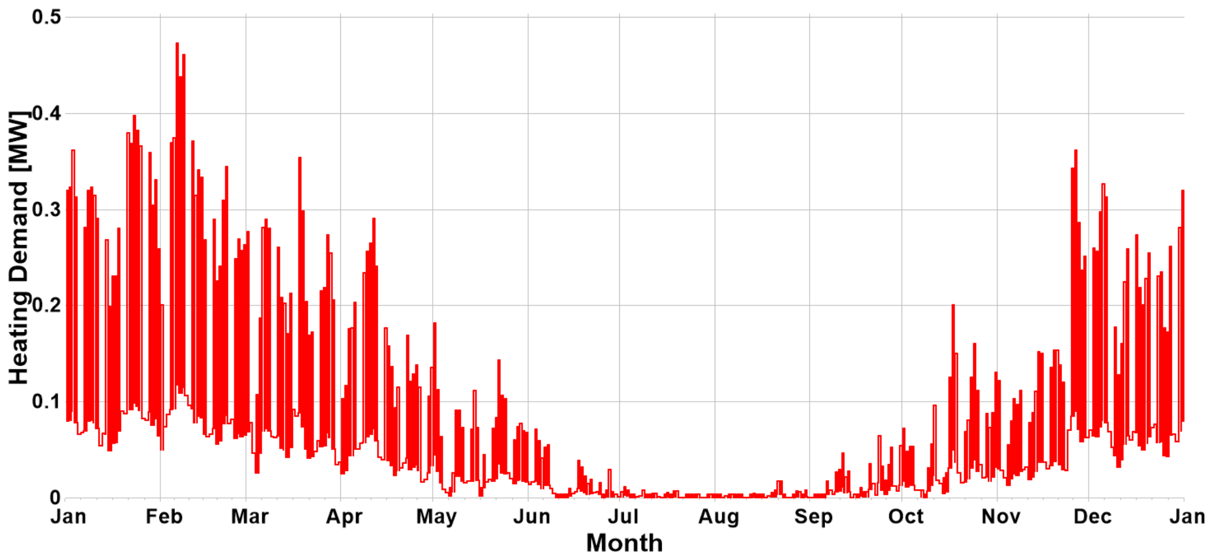

Figure 8: Annual heating demand profile of office buildings

Finally, cooling and electricity profiles of data centers were characterized on the basis of actual data (operation of IT loads throughout the whole day) simulated in the Renew IT project [34]. To generate the cooling demand profile, TRNSYS software was used. The following inputs were provided to the dynamic simulation models:

- Type of workload
- Contracted cooling power
- Set point ambient temperature

It was assumed that all data centers handle only data workload (data analytics, data caching and data serving). Figure 9 and Figure 10 show the annual cooling and weekly electricity demand profiles of data centers generated by simulation. The cooling demand profile is more concentrated in the summer season since the data centers are equipped with free cooling, which is active whenever ambient temperature is below 22°C. The weekly electricity demand remains the same throughout the whole year (as shown in Figure 10).

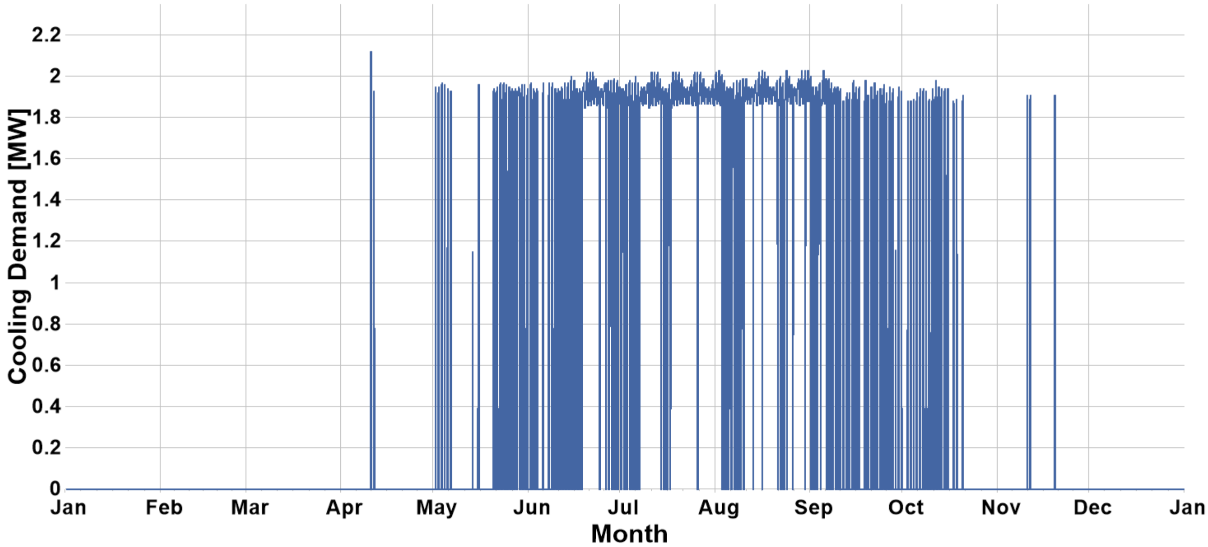

Figure 9: Annual cooling demand profile of data centers

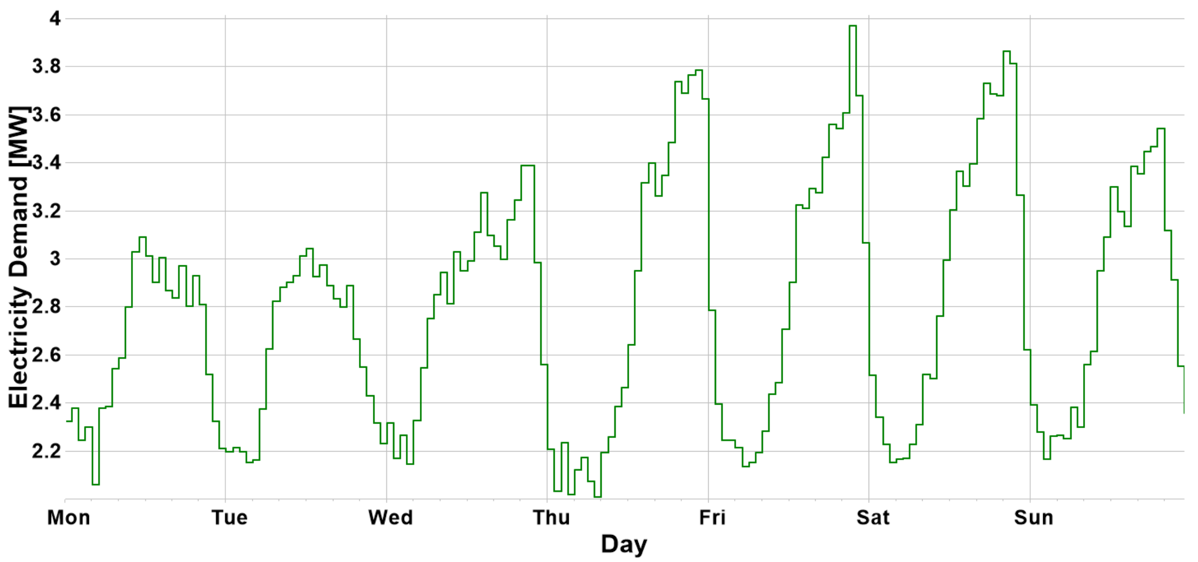

Figure 10: Weekly electricity demand profile of data centers

4. Supply modeling

Three distinct scenarios were considered for supplying the energy demand of Parc de l' Alba. The choice for the combinations of energy conversion units in the different scenarios were mainly dictated by the experience of the authors with previous similar DHC networks in Spain. The three scenarios are:

- Scenario 1: Solar cooling and Biomass cooling (SCBC)
- Scenario 2: Ground Source Heat Pumps (GSHPs)
- Scenario 3: Business As Usual (BAU)

Common to all scenarios is the incorporation of a biogas boiler in the ST-4 plant in 2017, which is taken out of service in 2020 (due to unavailability of fuel i.e., landfill gas, from 2020 onwards). The biogas boiler has a capacity of 1.5$MW_{th,h}$, with a thermal efficiency of 90 %.

From 2020 to 2030 (both inclusive), the demand is large enough to implement different energy conversion technologies in the new ST-5 plant. The peak power demands dictated the sizing of energy conversion units in these years. In all simulations, the operation strategy provided to the software was such that energy conversion units that produced energy most economically would run first and so on. For sizing the cold-water storage tanks, data was obtained from the Forum and 22@ DHC networks in Barcelona in Spain [25]. A cooling demand to volume ratio of 5 $MWh_{th,c}/year/m^3$ was defined to relate the cooling demand with cold storage size and was hence used to size the cold-water storage tanks in 2020, 2025 and 2030. For hot storage, it was assumed that 20 % of the heating demand would need to be stored, considering a storage time of 12 hours. Table 5 shows details of hot and cold storages added in 2020, 2025 and 2030 in the simulations.

Table 5: Volume and capacities of cold and hot storage tanks at ST-5 plant (2020-2030)

	2020	**2025**	**2030**
Cold water storage tank	6400 m^3; 29.8 $MWh_{th,c}$	11300 m^3; 52.4 $MWh_{th,c}$	9700 m^3; 45.0 $MWh_{th,c}$
Hot water storage tank	200 m^3; 5.8$MWh_{th,h}$	1620 m^3; 47.0 $MWh_{th,h}$	1000 m^3; 29.0 $MWh_{th,h}$

Another important point to be mentioned is that the existing ST-4 plant still has space for installation of two new cogeneration engines and an absorption chiller. Thus, in all scenarios, it was decided to install two new engines and an absorption chiller in 2025, having specifications shown in Table 6. The back-up natural gas boiler at the ST-4 is only allowed to run in the winter months for Scenarios 1 and 2, while it can run throughout the whole year for Scenario 3.

Table 6: Technical specifications of equipment installed at ST-4 plant in 2025 (all scenarios)

Energy Conversion unit	**Specifications**	**Quantity**
Cogeneration engines	3350 kW_e; 3280 $kW_{th,h}$; η_{el} = 44.9 %; η_{th} = 41.1 %	2
Double effect absorption chiller	5000 $kW_{th,c}$; COP = 1.3	1

4.1. Scenario 1: Solar Cooling and Biomass Cooling (SCBC)

For this scenario, it is assumed that the rooftop of the ST-5 plant was used to install parabolic trough collectors (PTCs). The hot water from these PTCs would be supplied to a double effect absorption chiller to produce cooling. For the remainder (major) cooling demand and heating demand, biomass boilers are installed and connected to double effect absorption chillers. Details of all energy conversion units installed in SCBC scenario are shown in Table 7.

Table 7: Technical specifications of equipment installed in SCBC scenario (2020-2030)

Energy Conversion unit	Specifications	Quantity installed each year			Total installed capacity by 2030
		2020	2025	2030	
Parabolic trough collectors	1088 m^2 ; 298 kW_{th} (417 $kW_{th,c}$)	1	-	-	298 kW_{th} (417 $kW_{th,c}$)
Absorption chiller (connected to solar collectors)	450 $kW_{th,c}$; COP = 1.4	1	-	-	450 $kW_{th,c}$
Biomass boiler	2,500 $kW_{th,h}$; η_{th} = 90%	1	1	-	55,000 $kW_{th,h}$
	5,000 $kW_{th,h}$; η_{th} = 90%	-	5	5	
Absorption chiller(s) (connected to biomass boiler)	3,300 $kW_{th,c}$; COP = 1.4	1	-	1	51,600 $kW_{th,c}$
	5,000 $kW_{th,c}$; COP = 1.4	-	6	3	

4.2. Scenario 2: Ground Source Heat Pumps (GSHPs)

In the GSHPs scenario, the cooling and heating demands are supplied by ground source heat pumps (GSHPs) that produce cooling and heating at the same time. The GSHPs produce 3.2 units of cooling and 4.2 units of heating, for every unit of electricity input to the compressor (these specifications are assumed to be the same as those of the units used in hospital de Mollet project in Spain [35]). As a consequence of higher heat output in comparison with cooling output for the same input, the GSHPs in this scenario are “oversized” in terms of heating capacity (since cooling demand is always higher than heating demand in Parc de l’ Alba and it is assumed that there is no drift in soil temperature occurring due to imbalance between the two types of thermal loads). Since GSHPs require very large areas of land on-site for digging boreholes, no new GSHPs are installed in 2030 and the new cooling and heating demands for that year are supplied by biomass boilers connected to double effect absorption chillers. Details of all energy conversion units installed in GSHPs scenario are shown in Table 8.

Table 8: Technical specifications of equipment installed in GSHPs scenario (2020-2030)

Energy Conversion unit	Specifications	Quantity installed each year			Total installed capacity by 2030
		2020	2025	2030	
Solar PV system	1800 m^2; 275 kW_e; η_{el} = 15.4%, Type: Monocrystalline	1	-	-	275 kW_e
Ground Source Heat Pumps	Input: 1214 kW_e; Output: 3900 $kW_{th,c}$, 5113 $kW_{th,h}$	1	-	-	34,00 $kW_{th,c}$, 5,113 $kW_{th,h}$
	Input: 9,368 kW_e; Output: 30,100 $kW_{th,c}$, 39461 $kW_{th,h}$	-	1	-	
Biomass boilers	5000 $kW_{th,h}$; η_{th} = 90%	-	-	5	25,000 $kW_{th,h}$
Absorption Chillers	5000 $kW_{th,c}$;COP = 1.4	-	-	5	25,000 $kW_{th,h}$

4.3. Scenario 3: Business as Usual (BAU)

In the BAU scenario, cogeneration engines are installed to sell electricity directly to the data centers from 2020 onwards (as opposed to buying it from the grid and then selling to the consumers as modelled in the previous scenarios). Exhaust heat from the engines would be used to satisfy the heating demand and would also be supplied to absorption chillers for producing cooling. For backup, natural gas boilers and a compression chiller are installed as well. Details of all energy conversion units installed in BAU scenario are shown in Table 14.

Table 9: Technical specifications of equipment installed in BAU scenario (2020-2030)

Energy Conversion unit	Specifications	Quantity installed each year			Total installed capacity by 2030
		2020	2025	2030	
Cogeneration engines	3,350 kW_e; 3,280 $kW_{th,h}$; η_{el} = 44.9 %; η_{th} = 41.1 %	3	1	5	30,150 kW_e; 29,520 $kW_{th,h}$
Double effect abs orption chillers	5,000 $kW_{th,c}$; COP = 1.3	1	1	2	20,000 $kW_{th,c}$
Single effect abso rption chillers	3,000 $kW_{th,c}$; COP = 0.75	-	2	1	9,000 $kW_{th,c}$
Natural gas boiler s	5,000 $kW_{th,h}$; η_{th} = 60%	1 (back up)	2	-	15,000 $kW_{th,h}$
Compression chill er	15,000 $kW_{th,c}$; COP = 4	-	1	-	15,000 $kW_{th,c}$

5. Economic modeling

Fuel prices provided to the EnergyPRO models from 2016 to 2030 are shown in the Appendix. Prices of natural gas and electricity have been inflated according to the percentages explained in section 2 while landfill gas and biomass are inflated at 2% (inflation rate of the Euro region). The price and maintenance costs of the biogas boiler (having a capacity of 1.5 $MW_{th,h}$), installed in 2017, are € 147,500 and € 6,250 respectively. Investment costs of various equipment in the different scenarios were available for present day and are inflated at 2% every year, so as to get the expected cost of the actual year in which they were integrated in the models.

Table 10: Investment costs of cold and hot storage tanks at ST-5 plant shows costs of the cold [25] and hot storage tanks [36] installed at ST-5 from 2020 to 2025. The specifications of these storage tanks have been shown previously shown in Table 5.

Table 10: Investment costs of cold and hot storage tanks at ST-5 plant

	2020	2025	2030
Cold water storage tank	€ 1,400,000	€ 2,700,000	€ 2,600,000
Hot water storage tank	€ 97,400	€ 290,000	€ 237,500

Cost of the new equipment installed at ST-4 plant in 2025 is shown in Table 11. Cost of engines and double effect absorption chillers have been provided by the management at Parc de l' Alba

Table 11: Investment cost of engines and chiller at ST-4 plant in 2025

Energy Conversion unit	Specifications	Total investment
Cogeneration engines	3350 kW_e; 3280 $kW_{th,h}$; η_{el} = 44.9 %	€ 3,700,000
Double effect absorption chiller	5000 $kW_{th,c}$; COP = 1.3	€ 1,100,000

For the ST-5 plant, the CAPEX of the SCBC, GSHPs and BAU scenarios are shown in Table 12, Table 13 and Table 14 respectively.

Table 12: Investment costs of energy conversion units installed in SCBC scenario

Energy Conversion unit	Total investment		
	2020	2025	2030
Parabolic trough collectors	€ 353,000	-	-
Absorption chiller (connected to solar collectors)	€ 277,000	-	-
Auxiliary equipment for solar thermal cooling system	€ 631,000	-	-
Biomass boiler	€ 1,172,000	€1,293,000	
	-	€12,940,000	€ 14,280,000
Absorption Chillers (connected to biomass boilers)	€ 659,000	-	€ 803,000
	-	€ 6,000,000	€ 3,650,000

Table 13: Investment costs of energy conversion units installed in GSHPs scenario

Energy Conversion unit	Total Investment		
	2020	2025	2030
Solar PV system	€390,000	-	-
Ground Source Heat Pumps	€8,762,000	-	-
	-	€74,650,000	-
Biomass boilers	-	-	€14,280,000
Absorption Chillers	-	-	€6,070,000

Table 14: Investment costs of energy conversion units installed in BAU scenario

Energy Conversion unit	Total Investment		
	2020	2025	2030
Cogeneration engines	€4,931,000	€1,815,000	€10,020,000
Double effect absorption chillers	€998,000	-	€ 1,216,000
Single effect absorption chillers	-	€1,322,000	€1,460,000
Natural gas boilers	€123,000	€272,000	-
Compression chiller	-	€1,484,000	-

Cost of the solar collectors was provided by a manufacturer based in Sweden [37], while the price of the absorption chiller was taken from [38]. For the GSHPs scenario, investment and maintenance costs were taken from a study carried out in France [39], including cost of drilling in the ground and construction of boreholes. Costs of the solar PV system were taken from IEA [40]. In the BAU scenario, investment costs of engines and natural gas boilers were provided by Parc de l' Alba management, while cost of the compression chiller was calculated from a guide published by the Catalan Energy Institute [41].

6. Results and Discussion

This section presents key results of the EnergyPRO simulations and economic analysis. Results are shown in a chronological order, i.e., first of the years 2016 till 2018 and then of 2020 till 2030 for the different scenarios.

6.1. Energy Performance

From 2016 till 2018, all three scenarios have identical simulation models. Energy balance of 2016-2018 is shown in Table 15. Energy demand may be seen in Figure 2 andFigure 3 in section 3. It must be stressed here that energy consumption refers to the actual amount of energy consumed while primary energy consumed is the total energy required to produce one unit of a consumed particular energy on site; including transportation, storage, distribution, delivery and any losses incurred in the process.

Table 15: Energy Balance at Parc de l' Alba from 2016 until 2018

	2016	**2017**	**2018**
Energy Consumption(MWh/year)			
Imported Electricity	16,800	17,000	17,000
Natural gas	92,900	94,900	92,000
Biogas	-	9,200	9,100
Primary Energy Consumption(MWh/year)			
Imported electricity	39,900	40,200	41,000
Natural gas	111,000	113,000	110,000
Biogas	**-**	4,600	4,600
Total	151,000	158,000	156,000

Even though the energy consumption has increased from 2017 to 2018, the primary energy consumption has decreased since there is a reduction in the use of natural gas by the backup boiler. This backup boiler not allowed to operate during the summer and priority was given to the more efficient biogas boiler, burning a cheaper fuel.

2020 is the year when increase in energy demand is large enough to justify development of the new ST-5 plant, where different energy conversion technologies are implemented in accordance with the different scenarios (SCBC, GSHPs and BAU). Energy balances from 2020 till 2030 are shown in Figure 11 and Figure 12.

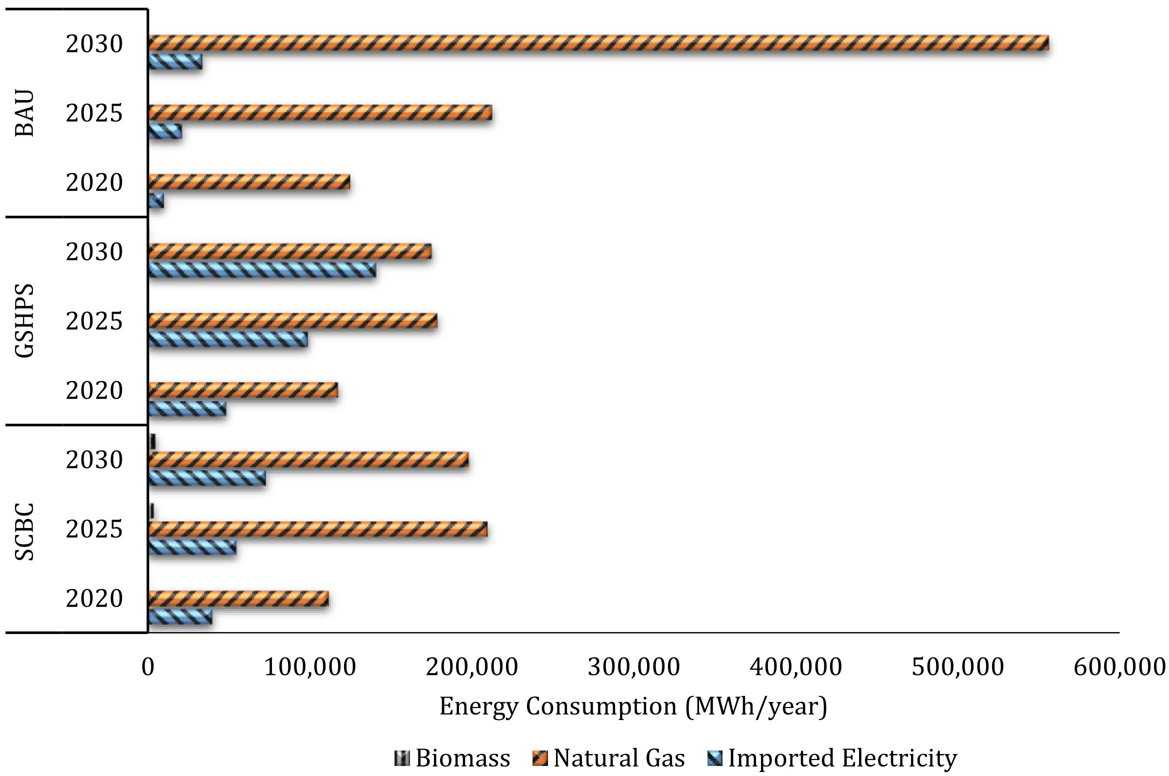

Figure 11: Energy Balance for different scenario of the basis of energy consumption (MWh/year)

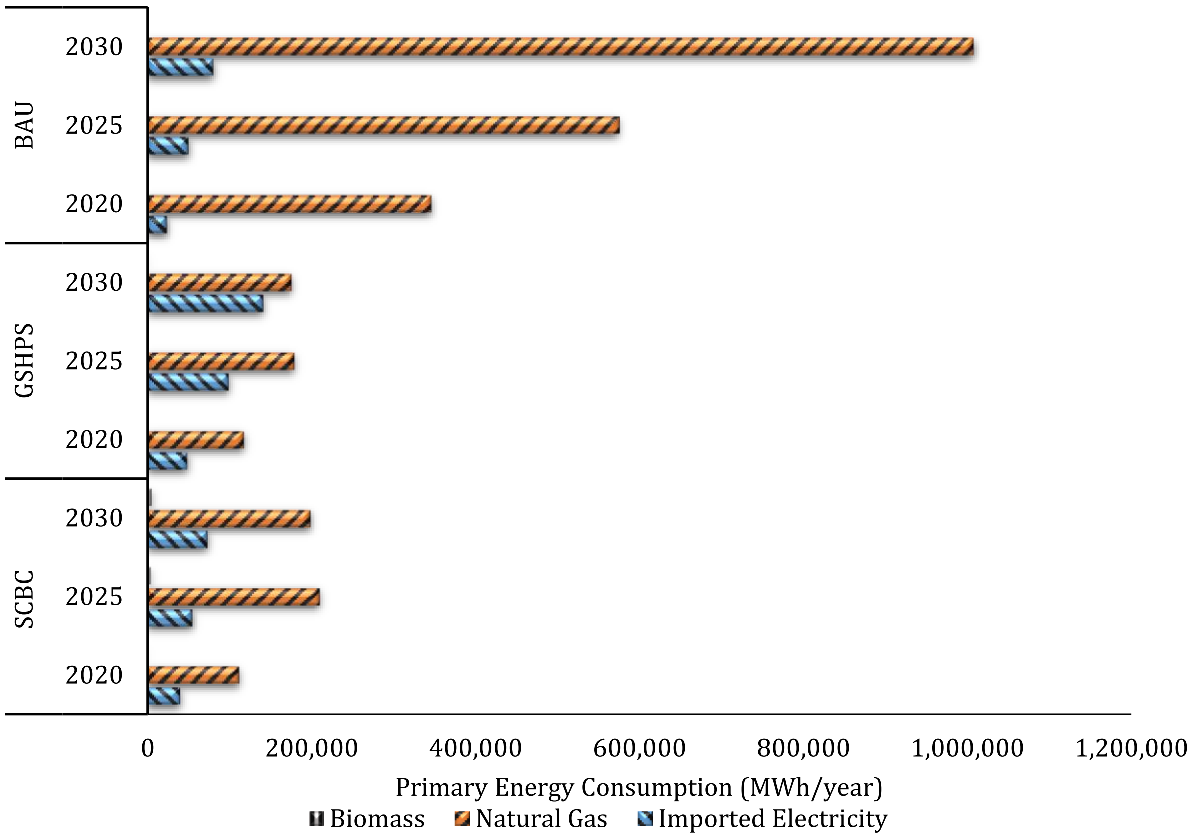

Figure 12: Energy Balance for different scenarios on the basis of primary energy consumption (MWh/year)

By comparison between Figure 11 and Figure 12, it can be seen that the GSHPs scenario has a larger energy and primary energy consumption as compared the SCBC scenario. This is because of the fact that the former relies more on electricity to run the GSHP units while the latter uses biomass as the main fuel, which has a lower PEF as shown previously in Table 4 in section 2.

The BAU scenario has a drastically larger consumption of energy, which is clearly due to burning of much more natural gas. The new ST-5 plant in this case relies only on the new cogeneration engines for energy production. Moreover, the old engines in the ST-4 plant are running more hours in comparison with SCBC and GSHPs scenario, since there are no RES based energy conversion units in BAU scenario. Moreover, as explained previously, in the BAU scenario the backup boiler at the ST-4 plant is allowed to operate throughout the year and not only in winter months as in the SCBC and GSHPs scenario, where priority is to run the RES based units.

6.2. Environmental analysis

Table 16 shows the CO_2 emissions from 2016 until 2018, while emissions from 2020 until 2030 are shown in Table 17.

Table 16: CO_2 emissions in Parc de l' Alba from 2016 until 2018

	2016	2017	2018
CO_2 emissions (tons/year)	29,400	30,900	30,400

Table 17: CO_2 emissions in Parc de l' Alba from 2020 till 2030 (all scenarios)

	2020	2025	2030
SCBC scenario (tons/year)	38,600	71,800	107,800
GSHPs scenario (tons/year)	40,800	70,300	111,170
BAU scenario (tons/year)	76,300	128,500	224,500

From Table 17, BAU scenario shows more than twice the amount of CO_2 emissions in 2030, mainly because it is burning more natural gas in comparison to the RES based scenarios, due to the new cogeneration engines and new boilers at ST-5 plant and longer running hours of the old engines and old boiler at the ST-4 plant.

6.3. Economic results

The major economic indicators obtained from the EnergyPRO simulations and the P & L analysis are mainly the revenues, operating costs, EBITDA (Earnings before Interests, Taxes, Depreciation and Amortization) and NPV. Figure 13 show all these indicators (except NPV) for 2016-2018 and 2020-2030 respectively.

Table 18: Economic indicators of Parc de l' Alba from 2016 till 2018

	2016	2017	2018
Revenues	€ 7,651,000	€ 8,820,000	€ 10,155,000
Operating Costs	€ 5,080,000	€ 5,604,000	€ 5,887,000
EBITDA	€ 2,571,000	€ 3,216,000	€ 4,268,000
Free Cash Flow	€ 629,000	€ 1,962,000	€ 2,722,000

The NPV is calculated until the end period for each scenario and is thus shown graphically in Figure 14: Net Present Value (NPV) of each scenario for each scenario.

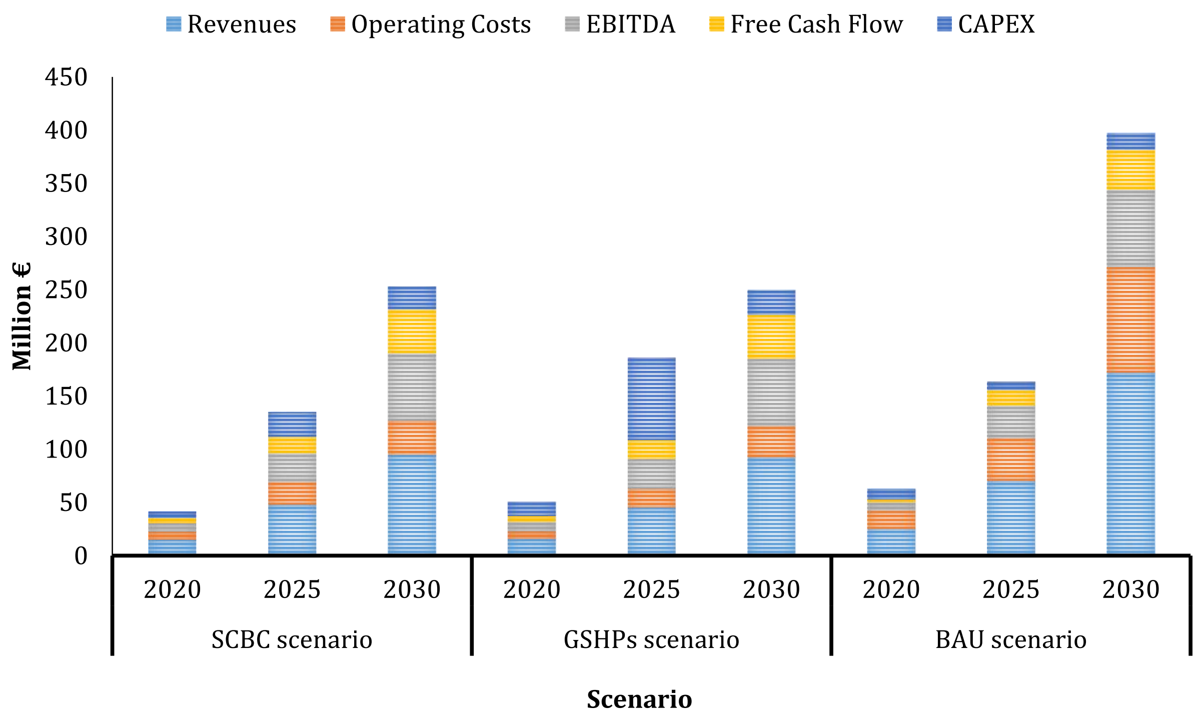

Figure 13: Economic indicators of the different scenarios

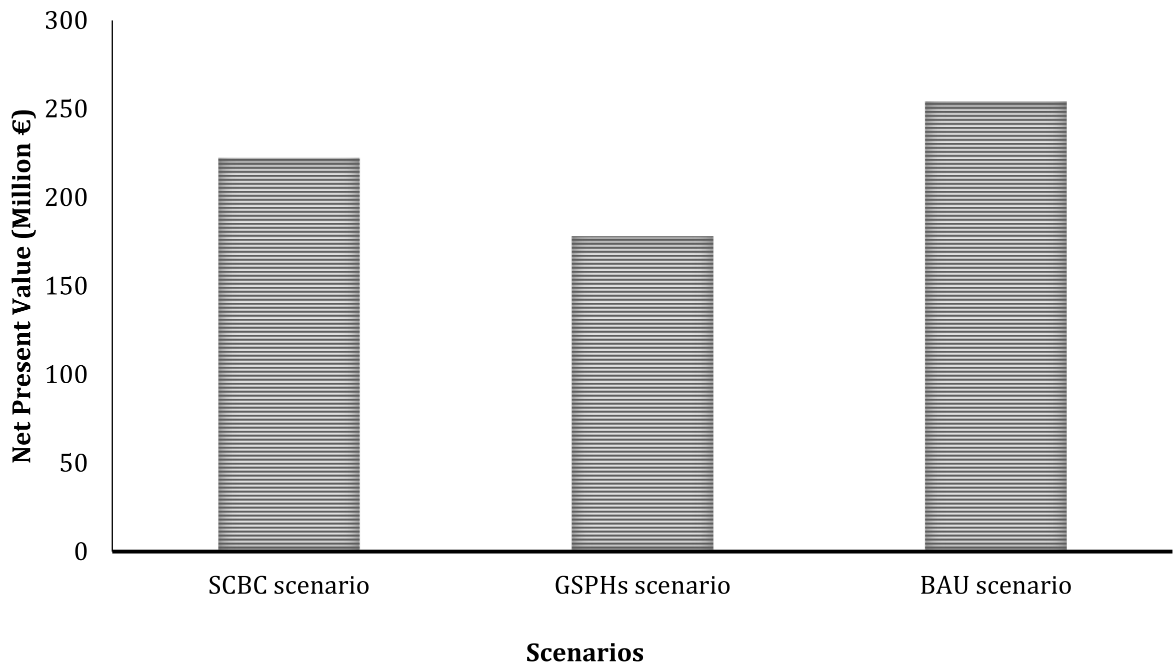

Figure 14: Net Present Value (NPV) of each scenario

By comparing the two RES based scenarios from Figure 13 and Figure 14, it can be seen clearly that the SCBC scenario is more profitable in comparison to GSHPs scenario, due to its lower CAPEX and higher NPV. Apparently, GSHPs have an average efficiency which is four times that of boilers burning biomass and providing heat to absorption chillers in the SCBC scenario. However, the CAPEX in the GSHPs scenario is much higher than SCBC scenario and moreover, cost of imported electricity is higher than biomass and it increases at a faster rate (than that of biomass), as explained in section 2.

When doing the comparison as a whole, it is indeed the BAU scenario which is most profitable. Not only does it have the lowest CAPEX in comparison to the RES based scenarios, but it has an additional revenue stream generated by exporting excess electricity produced to the grid.

Conclusion

The paper presents a technical, economic and environmental evaluation of implementing different RES based systems in the expansion of a fossil fuels based DHC plant in a Technology Park in the region of Catalonia in Spain. The expansion of the existing plant was dictated by the forecast of increased demand of cooling, heating and electricity in the Technology Park. The aim of the study was to evaluate which combination of RES based systems would be best suited for integrating into the expansion of the DHC plant.

In context of the given assumptions and input parameters, the results of the simulations and economic evaluation showed that when deciding between RES based technologies, SCBC scenario is more feasible option when compared to the GSHPs scenario, due to its lower primary energy consumption (624,380 MWh/year in 2030 vs. 665,367 MWh/year), lower CO_2 emissions (107,753 tons/year in 2030 vs. 111,166 tons/year) and higher NPV (222 million € vs. 178 million €) with lower CAPEX.

Considering the SCBC scenario, solar thermal cooling has great prospects for primary energy savings and reduction of CO_2 emissions but in this study , the limited area of ST-5 plant`s roof was the reason that solar thermal cooling could not contribute a lot in the large cooling demand of Parc de l'Alba. Only 2% of the cooling demand in 2020 came from the solar thermal system, dropping to a mere 1% in 2025 and 2030. This was not surprising because the maximum output of the solar thermal cooling system installed was 417 $kW_{th,c}$, whereas the total cooling capacity of ST-5 plant was 3717 $kW_{th,c,}$ 39,717 $kW_{th,c}$ and 58,017 $kW_{th,c}$ in 2020, 2025 and 2030 respectively. In the GSHPs scenario, the units are producing more heating than cooling, as explained in section 4.2. For Parc de l' Alba, this excess heat is useless and hence rejected to the soil. Basically, implementation of GSHPs for simultaneous production of cooling and heating is not feasible for office buildings and data centers located in a Mediterranean climate (Catalonia), where cooling is the main energy demand and not heating. Additionally, digging of boreholes for installation of GSHPs requires large land areas, an additional investment that has to be taken into account.

In contrast to solar thermal cooling and GSHPs, biomass boilers burning woodchips connected to double effect absorption chillers are apparently the most favorable solution in this study. Not only is biomass cheaper than importing electricity, but there are large savings in primary energy consumption as well (wood chips and electricity have PEFs of 0.034 and 2.368 respectively as shown in table 7). Moreover, for the same cooling capacities, biomass boilers and absorption chillers need less land area for installation as compared to GSHPs and solar thermal cooling systems.

Thus, in the frame of this study, based on the given assumptions and inputs, biomass boilers connected to absorption chillers with assistance from solar thermal cooling are the most feasible renewable energy system technology, for the large district heating and cooling network of Parc de l' Alba in Spain.

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Appendix

For the ST-4 plant at Parc de l’ Alba, revenues from heating, cooling and electricity sales comprise of capacity payments and a variable price. Additionally, heating and cooling sale revenues comprise of a connection payment. The connection costs are paid just once whenever a new consumer in Parc de l’ Alba signs an agreement to buy heating and cooling from the plant. The capacity payment refers to payment made every year by the consumer in accordance with the power they have contracted from the plant. Finally, the variable price is payment made by the consumer for each unit of energy purchased. Table 19 and Table 20 show details of all these revenues for the year 2015.

Table 19: Revenues from heating and cooling sales at Parc de l' Alba for base model (2015)

Payment type	**Value for cooling**	**Value for heating**
Connection payment	14,580 €/$MW_{th,c}$ connected	48,200 €/$MW_{th,h}$ connected
Capacity payment	23,000€/$MW_{th,c}$ /year	14,000 €/$MW_{th,h}$/year
Variable price	34.8 €/$MWh_{th,c}$ sold	34.8 €/$MWh_{th,h}$ sold

Table 20: Revenues from electricity sales at Parc de l' Alba for base model (2015)

Payment type	**Value for electricity (Synchrotron)**	**Value for electricity (grid)**
Capacity payment	617,130 €/year	529,200 €/year
Variable price	114.2 €/MWh_e sold	113.2 €/MWh_e sold

All expenses of the plant are shown in Table 21 and Table 22 for 2015. Note that Parc de l’ Alba pays only the marginal electricity production cost when it buys from the electric grid and hence the large difference between the revenue it earns per unit energy by selling to the grid, compared to what it pays per unit when it needs to purchase from the grid.

Table 21: Fuel expenses at Parc de l' Alba in 2015

Fuel	**Value**
Natural gas	37.8 €/MWh_{th} (0.402 €/m^3)
Electricity imported	40.7 €/MWh_e

Table 22: Maintenance expenses at Parc de l' Alba in 2015

Maintenance type	**Value**
Fixed maintenance	245,100 €/year
Variable maintenance	13.3 €/MWh_e from gas engines
Overhaul of engines	6.8 €/hour operation

Fuel prices provided to the EnergyPRO models from 2016 to 2030 are shown in Table 23 [25].

Table 23: Fuel prices in Parc de l' Alba from 2016 till 2030

Year	**2016**	**2017**	**2018**	**2020**	**2025**	**2030**
Natural gas (€/kWh_{th})	0.040	0.043	0.046	0.050	0.072	0.104
Imported electricity (€/kWh_e)	0.041	0.045	0.049	0.060-0.068	0.094-0.129	0.149-0.212
Landfill gas (€/kWh_{th})	-	0.0082	0.0083	-	-	-
Biomass (€/kWh_{th})	-	-	-	0.033	0.036	0.040

The specifications of different categories of energy consumers at Parc de l’ Alba, including current and future ones, are shown in Table 24 , including the year in which they will be connected to the DHC network.

Table 24: Details of expected energy consumers of Parc de l' Alba till 2030

Consumer name in software Model	**Consumer type**	**Energy service(s) provided**	**Year of connection**	**Number of building(s)**	**Total floor area (m^2)**
Synchrotron	Particle Accelerator	Heating, Cooling, Electricity	2010	1	35,000
Plot 1	Offices	Heating, Cooling	2013	1	43,000
Plot 2	Data Center	Cooling	2016	1	51,230
Plot 3	Offices	Heating, Cooling	2017	1	81,230
Plot 4	Offices	Heating, Cooling	2018	1	89,230
Plots 2020-DC	Data Center	Cooling, Electricity	2020	1	93,230
Plots 2020-Off	Offices	Heating, Cooling	2020	2	108,230
Plots 2025-DC	Data Center	Cooling, Electricity	2025	1	112,230
Plots 2025-Off	Offices	Heating, Cooling	2025	51	732,000
Plots 2030-DC	Data Center	Cooling, Electricity	2030	1	736,000
Plots 2030-Off	Offices	Heating, Cooling	2030	31	112,2000

EnergyPRO does not have the capability to dimension the distribution network because the return and supply temperatures of the fluids in the network cannot be input to the simulation models. For this purpose, LOGSTOR calculator, which is an internet-based program, was used for calculating the heating and cooling line losses. The major information used for calculating the losses is shown in Table 25 . Note that the various sections of the DHC network had varying pipe diameters.

Table 25: Parameters for calculating transmission and distribution losses for Parc de l' Alba

Parameter		**Value**
Number of summer days		182
Number of winter days		183
Summer ambient temperature		19.5°C
Winter ambient temperature		11.6°C
Soil cover		1500 mm
Soil thermal conductivity		1.6 W/m-K
Pipe material		Steel
District heating	Supply temperature	90°C
	Return temperature	75°C
	Internal pipe diameters (mm)	100/125/150/500
District cooling	Supply temperature	5°C
	Return temperature	12°C
	Internal pipe diameters (mm)	150/200/300/400/500/700/800