Cost-effectiveness of integrating on-site Renewable Energy and Storage in High Power Charging stations for Electric Vehicles

Case study of 2 IONITY stations in Spain and Sweden.

Master's thesis in Electrical Engineering

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DEPARTMENT OF ELECTRICAL ENGINEERING

CHALMERS UNIVERSITY OF TECHNOLOGY
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MASTER'S THESIS 2021

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ABSTRACT

The fast pace introduction of Electric Vehicles into the European markets has intensified the need for High Power Charging stations along highways to enable long-distance travelling as convenient as with an internal combustion engine car. To make sure that the system is cost-effective regarding the electrical grid connection and that it has the lowest environmental footprint, the integration of on-site renewable energy production and battery energy storage is studied. Two IONITY high-power charging stations in Spain and Sweden are analysed. The objective is to find a viable solution regarding the electrical supply, considering the grid tariffs and the solar and wind resources for each location. The simulations are performed using HOMER Energy software, which optimizes the system based on the Net Present Cost. Several cases are studied setting different grid size limits to determine the need for on-site battery storage in locations where the distribution grid does not have enough capacity. In Spain, a system with much solar PV will have a significantly lower cost than only connecting the chargers directly to the grid. In Sweden, solar PV or wind turbines have a similar cost than connecting only the chargers directly to the grid. Storage would be cost-effective if costs lower to 150 €/kWh or in cases with both a low demand for charging and low power grid connection. However, the grid connection needs to be oversized, so it meets the future demand, which all the tendencies show will be growing due to stricter emissions regulations and to government's willingness.

Keywords: high power charging; renewable energy; solar PV; storage; electric vehicles; IONITY.

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Responses of the survey provided by the Electric Vehicle Users Association of Spain (AUVE) and the Electric Vehicle Association (EVA) Scotland were greatly appreciated. For this reason I would also like to thank Martin Lee of the EV news daily podcast to share with his audience my survey. Finally, I am particularly grateful for all the IONITY staff that answered the survey as well as other people who did it via the social networks post I made.

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Finally, I wish to thank my parents for the support given that even with distance has been important and to express gratitude to the Erasmus friends of Göteborg for their encouragement throughout my study.

CONTENTS

LIST OF ABBREVIATIONS

AC – Alternating Current

BESS – Battery Energy Storage System

CAPEX – Capital Expenditure

CCS – Combined Charging Standard

CPO – Charge Point Operator

DC – Direct Current

DSO – Distributor Service Operator

EV – Electric Vehicle

GHI – Global Horizontal Irradiance

HPC – High Power Charging

HV – High Voltage

ICE – Internal Combustion Engine

Li-ion – Lithium-ion

LV – Low Voltage

LVDB – Low Voltage Distribution Board

MaaS - Mobility as a Service

MSP – Mobility Service Provider

MV – Medium Voltage

OEM – Original Equipment Manufacturer

O&M – Operation and Maintenance

PV – Photovoltaic

PVGIS – Photovoltaic Geographical Information System

RE – Renewable Energy

1. INTRODUCTION

Among all challenges that our society has for climate change, reducing the emissions from road transportation is one of the most important ones. Electric Vehicles (EVs) are key elements to reduce CO_2 emissions as well as to improve air quality in metropolitan areas. However, for making the transition possible from internal-combustion engines (ICEs) to electrical, charging infrastructure is needed. Home or work charging at low power is the easiest and cheapest way to charge an EV and does not imply as many challenges as fast charging infrastructure. Fast charging is used for long distances travels as well as for people that cannot charge at home. Because of the lower range of EVs compared to ICEs cars, stops every 200-300 km are needed when travelling with EVs. Therefore, a network of High Power Charging (HPC) stations is vital to make long distance travelling almost as fast as vehicles with combustion engines, but with a much lower environmental impact. On-site renewable energy (RE) supply for HPC stations is a way to both reduce the cost for high power charging and reduce the CO_2 emissions from the electricity generation. Finally, from a customer perspective, it will be friendlier as the final user will see that the energy he is consuming comes directly from RE sources. In the same way it will give more reasons to the public to switch to EVs.

1.1. Background

The author became interested in electromobility back in 2018 when he wrote the Bachelor Thesis titled *Implementation of fast charging points for EVs in a service station* at Universitat Politècnica de Catalunya. The conclusions of the Thesis were that it is cost-effective to install a fast-charging station in a service station that has a significant traffic flow and that seemingly minor factors such as the possibility to pay by credit card or the coverage of the charging area with a canopy are very important to improve the user experience. Then it was found that stations with at least two chargers and not single points, need to be implemented all over the country so the risk of queue is minimized. All these factors, as well as planning a bigger electrical connection than the initially needed, are vital to accelerate the transition to EVs.

The internship at IONITY, a European company that implements and operates HPC stations along the major highways has given experience in the technical details needed for this type of stations as well as with the permitting procedures in Spain. Moreover, it has deepened with the features of the hardware suppliers as well as with the advance of the implementation in Europe and particularly in Spain. Back in 2018, there were only fast charging publicly owned points, while now private companies are starting to install them. Lastly, since the presentation of the Bachelor Thesis there has been a close contact with the EV user association of Spain (AUVE) and this has helped to see the customer experience when charging.

Other research in this field performed by Domínguez-Navarro et al. [1] showed that integration of renewable energy in a fast-charging station can improve its profitability, but it needs a connection to the grid or a storage system to balance the intermittence of RE. However, the way this study used to model the EV demand was based in probabilistic distributions, which do not follow the real ones. Then, J. Brombach, F. Mayer, J. Winkler and others [2] revealed the possibility of integrating wind energy systems to charging infrastructure, even though only the technical part is detailed, with a lack of the economic viability of it and results of case studies. According to another paper of A. Khan, S.

Memon and T. Sattar [3], it is technically viable to integrate solar energy to a fast-charging station with electrical control systems.

1.2. Aim of the project

This thesis has the main goal of enabling a fast and cost-effective roll out of HPC stations by exploring how the total cost can be reduced by:

- Producing electricity with RE
- Reducing the cost for grid connection when it is shared by both HPC and RE
- Finding a cost-effective sizing of the grid connection
- Analysing if and when on-site energy storage can reduce the overall cost

Therefore, the aim of the thesis is to find synergies which comes from combining HPC and RE. Two cases will be studied and compared: a IONITY station in Sweden and one in Spain.

It has been written due to the huge deployment of charging infrastructure that is already happening and will continue to grow. In a moment where there is an important demand of these stations it is key to profit the lowering prices of RE technology to effectively integrate both. Technically, it will be better because the grid will not have to support that much power and it will allow distributed zero-emission generation. Then, it can also be economically viable as, apart of saving from the energy and part of demand charge of the grid, it will allow to sell the not used energy back, making considerable revenues.

1.3. Limitations

The main source for the RE resources is the Photovoltaic Geographical Information System (PVGIS) from the European Commission for the wind speed and photovoltaic (PV) production of Spain. Regarding the PV production of Sweden, the data of Göteborg Energi is used. There is a limitation of time records in these data: 2007-2016 in the case of PVGIS and 2020-YTD 2021 for the data of Göteborg Energi.
The core tool used in this study is the software HOMER Grid/Pro. Hence, the results are limited to the calibration of the model and the accuracy of the simulations of this program.
The potential costs of buying or renting the lands where the PV panels would be installed are not considered in this study. Regarding the comparison of building a Medium Voltage (MV) line, there the rights to be paid to the landowners to install the electrical infrastructure are neither considered.
The potential solutions evaluated in this thesis are just some alternatives that could be implemented in the chosen locations, although there are other multiple options that could have been studied such as hydrogen storage.

1.4. Method

First, a literature study on previous papers discussing the topic was reviewed. Then the objectives of the Thesis were fixed, and a plan of the tasks made.

Prior to developing a detailed model, rough calculations were done using the online REopt tool of the National Renewable Energy Laboratory (NREL) of the United States. Then, a search for suitable software for doing the analysis was done. Finally, after trying different programs such as MATLAB Simulink or TRNSYS, HOMER Pro/Grid was selected. A major advantage of this software is that it enables to input the different hourly and monthly grid rates of the utility. Then, it also has an optimizer based on the Net Present Cost (NPC).

Once the program for doing the simulations was decided, all the data had to be imported. Solar irradiation and wind speed hourly data were downloaded from the PVGIS tool of the European Commission and then they were translated to a format suitable to input them into the model. For Sweden, PV production patterns of Göteborg Energi with a time step of 15 minutes were given. Following that, data were normalised and input to the model.
Then different hardware's were chosen for each resource. While solar PV does not differ that much from the different manufacturers as it is a scalable system, wind turbines of different capacities had to be selected so a solution with a rounded number could be found. The possible integration of a Battery Energy Storage System (BESS) was also input to the model. Once all the technical data from the sources was added, the EV charging load was inserted. It consists of the charging profiles that were forecasted for 2025. These ones differ from weekdays to weekends and a summer increase was also considered.

Regarding the economic data, needed for the model, first the Cost of Acquisition Expenditure (CAPEX) and Operation and Maintenance (O&M) costs of the elements described above were inserted. Then, the different grid tariffs of Spain and Sweden were added, with the real different energy and demand charges depending on the hour and time of the year for both countries.

Prior to run the simulations, the possible capacities available for each component -solar, wind and BESS- were inserted or optimized by HOMER depending on what was chosen. To reduce the duration of the simulations, first different capacities were entered to the model so the scale for each case was known. Then, simulations were run based on this scale and the program found out the optimal limit.

The results were then verified, and more simulations were done with different grid power limits. Moreover, a sensitivity analysis with different charging sessions per day was also done. Finally, the results with the optimal size of PV, wind and the BESS were obtained as well as the NPC and other economical rates.
In Figure 1.1 the procedure followed for achieving the results can be seen.

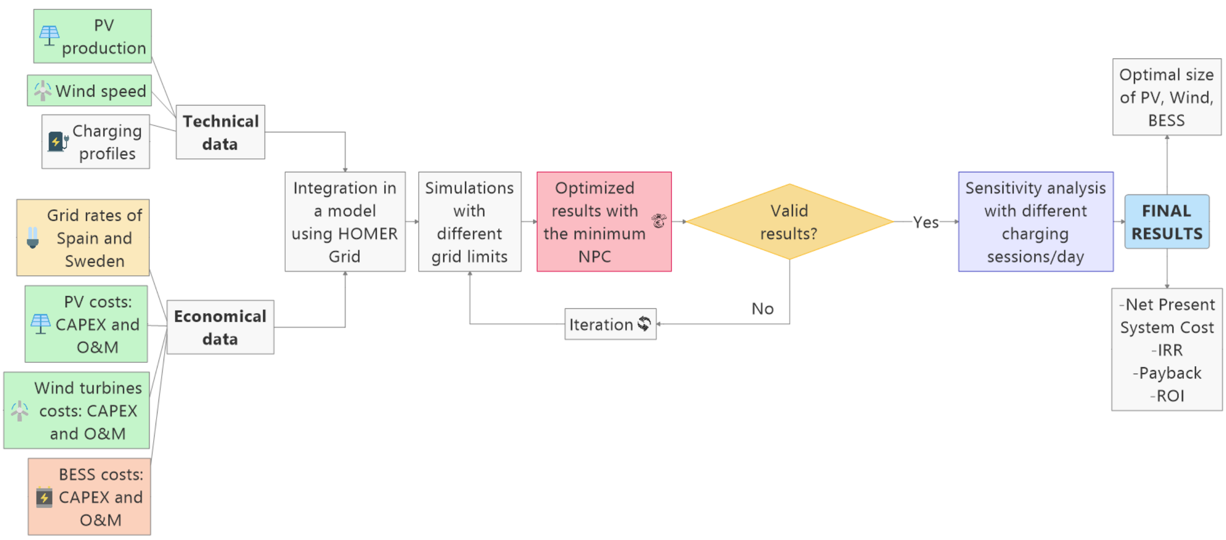

Figure 1.1: Procedure followed for achieving the results.

1.5. Outline of the thesis

This report is divided into 9 Chapters. After the introduction, Chapter 2 contains general background information regarding HPC stations, as well as existing examples of integration of RE in a HPC station. Chapter 3 presents the results of the survey of EV users all over Europe. In Chapter 4 it can be found a description of HOMER Pro and Grid software, the base tool of this study. In addition, in Chapter 5 the characteristics of the RE integration are detailed as well as the utility tariffs and the EV charger profile forecasted. In Chapter 6, the results from the simulations are presented, both the Swedish and Spanish cases. Chapter 7 consists of the suggested implementation of both cases. Finally, the discussion about the obtained results can be found in Chapter 8, while the conclusions drawn in this study are included in Chapter 9 along with the suggested further investigations.

2. HIGH POWER CHARGING AND EXAMPLES

In the last years, with the accelerated launch of different EV models, the infrastructure for charging them has also evolved. Starting with the easiest way to plug an EV -into a Schuko 3,7 kW wall plug- until the 350 kW HPC stations, all the options have seen an important growth.
Charging can be divided into Alternating Current (AC) charging, done usually at night or at the workplace, with a maximum of 22 kW, and Direct Current (DC) charging, a faster option usually used for a short stop during a long trip. This last technology is still evolving and depends on different parameters such as the maximum power that the car can accept, the battery size, the battery State of Charge (SoC), the ambient temperature and the maximum output the charger can deliver.

The first DC chargers to appear were the 50 kW ones, that can be seen inside cities, in supermarkets and service stations. Nearly all the EVs can charge at 50 kW power but the charging time is about 1 h to have 50 kWh, which is sufficient for about 250 km of range. One hour is still too much for a short stop done during a long trip. Therefore, to shorten the charging times, chargers with more than 100 kW of power have been rolled out in the market since 2018. At the same time, Original Equipment Manufacturers (OEMs) have prepared their new EVs to be capable of reaching charging powers of 100 kW or more. However, to protect the battery, the maximum power is only achieved in low SoC and then it decreases even if the charger can deliver more. This is critical when analysing HPC and it can be seen in Section 5.2.

Most HPC stations have two or more charging points which can deliver more than 100 kW each. For chargers of more than 175 kW, the power electronic cabinets are set apart from the charging point itself. This element usually consists of one cable with the Combined Charging Standard (CCS) connector[1], a Human Machine Interface and a RFID reader. The DC chargers are connected to the Internet via 3G or Ethernet so the Charge Point Operator (CPO) can remote control them, and the user can also activate them with an app. Concerning the electrical connection needed for these stations, it is nearly always done via a transformer connected to the MV grid[2]. The size of these transformer stations varies from 400 kVA to 2400 kVA, with common standard sizes being 630, 1000 and 1250 kVA. Then a switching station is needed to be connected to the point given by the Distributor Service Operator (DSO). The layout of an IONITY HPC station using the ABB hardware can be seen in Figure 2.1.

Regarding examples of integration of RE to HPC stations, there are some cases that have been rolled out in the last years. The largest one is the charging hub of Braintree (UK) built and operated by GRIDSERVE. It consists of 12 DC Chargers – up to 350kW, other 12 DC Chargers – up to 90kW and 6 AC Chargers – up to 22kW apart from 6 TESLA Superchargers. It has a 200 kWp solar PV installation in its canopies and a 6 MWh BESS with a 5 MW grid connection [4]. A recent example in the Nordic countries, very similar to the installation proposed in this study is the newly built Circle K station in

[1] Depending on the charger configuration there can be a second cable with the Japanese standard connector CHAdeMO and a 2nd or 3rd cable with the CCS connector which can be used at the same time, sharing the power of the charger.
[2] There are examples where back-up batteries connected to a low power LV point, have been used to feed a HPC station in places where there is no possibility to be connected to the MV grid.

Kongsbergporten, Norway. It has six 300 kW DC chargers with dual charging cables, which can be used by up to 12 cars at the same time. It is covered by a canopy with solar panels on it. The canopy of the 'usual' gas station is also covered by PV panels and there is also a BESS [5]. In Figure 2.2 a photo of this station can be seen.

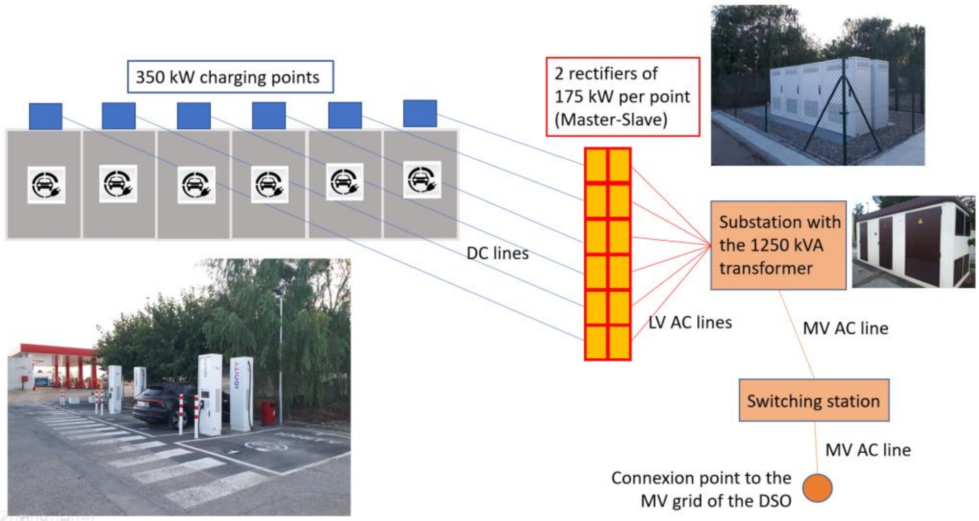

Figure 2.1: Layout of an IONITY HPC station using the ABB hardware.

Figure 2.2: Photo of the Circle K HPC station at Kongsbergporten, Norway [6]

Apart from that, all Fastned stations have canopies with solar PV integrated on them, which have an estimated capacity of 100 kWp. Then, there are other sites that are currently being built like the Sortimo Campus Electromobility in Zusmarshausen (Germany), which will be the largest solar filling station in the world. It will have 24 HPC points of up to 350 kW and 120 fast charges of up to 50 kW. Transsolar developed the net-zero energy concept for the site and evaluated it with dynamic simulation. The results show that a 3,000 kWp PV system on the roof of the factory hall with a 1,200 kWh Lithium-Ion (Li-ion) storage is the optimal solution for this site [7]. In France there is a project of Kallista Energy, a leading wind turbines company, to deploy 80 HPC stations connected to these turbines [8]. As stated in their website, hydrogen production unit powered by wind turbines could be added depending on the progress of this technology. Surplus energy produced by the wind turbines could later be stored in stationary batteries too [9].

3. ELECTRIC VEHICLE USER SURVEY

To get to know better the current EV users opinion of the topic of the Thesis as well as to design the most realistic charging profiles, a survey was conducted. It was sent to different EV users associations of Europe and got feedback of 2 of them: the Spanish EV user association (AUVE) and the Electric Vehicle Association (EVA) of Scotland. Then, it was also published in the Teams General channel of IONITY and in the LinkedIn and Twitter profiles of the author. In this last one, thanks of the cooperation of the EV news daily podcast, a bigger audience was reached. Finally, after the first launch on the 22nd of March 2021 it was opened until the 25th of April 2021 and 293 answers were collected in total.

3.1. Survey structure

As Figure 3.1 illustrates, it consists of 10 questions separated into 3 sections. The 2nd section, in purple, is only entered if the user has used a fast-charging station. Then, all the blue questions are common for everyone.

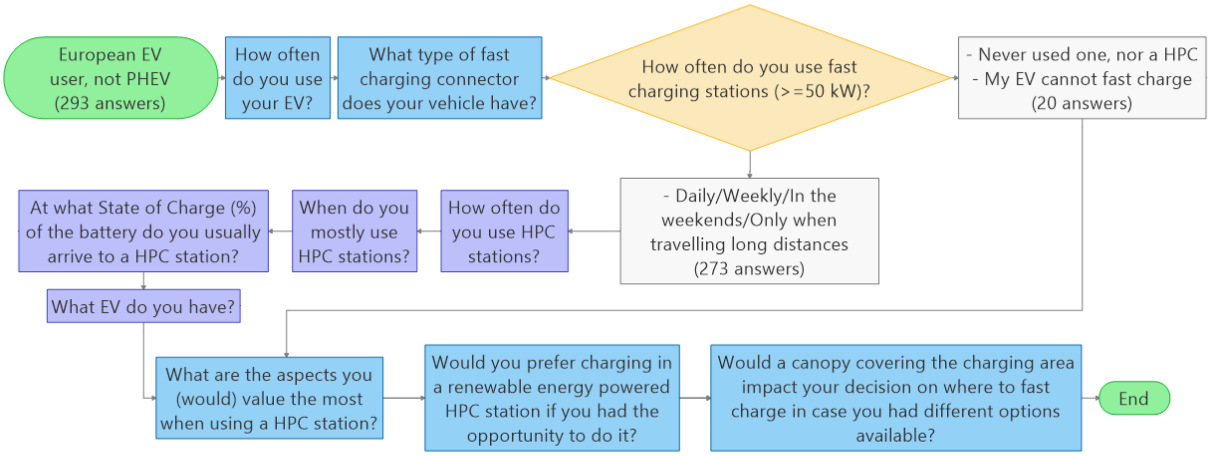

Figure 3.1: Structure of the EV user survey with the different sections and questions.

3.2. Survey results description

A brief analysis of each question of the survey is done and showed in this section.

In Figure 3.2 it can be seen that the vast majority of drivers use their EV daily. Only a 3% of them use it once a week.

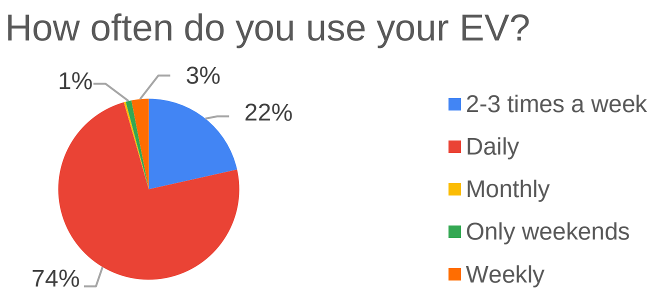

Figure 3.2: Results of the question of how often your EV is used.

As it is stated in Figure 3.3, a major part of the users has the CCS European standard connector. Only a 14 % of them have the CHAdeMO -Japanese- one, while a 6 % does not have any. Finally, a 7 % have the Tesla type 2 DC connector of Model S and X.

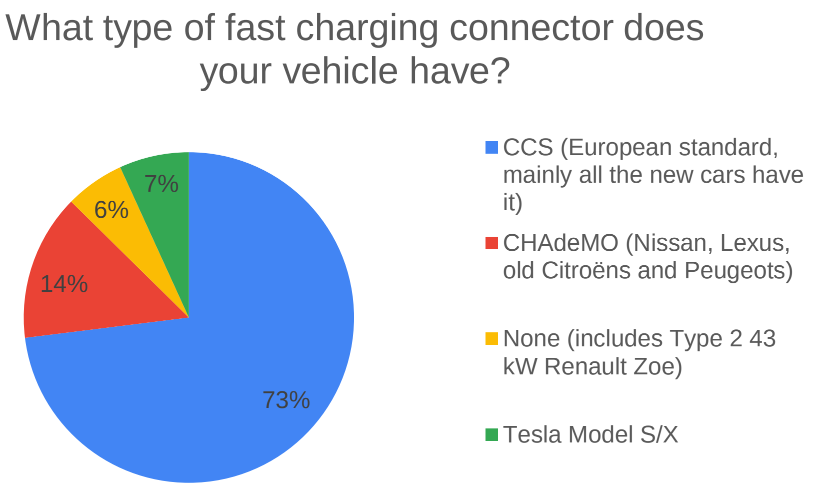

Figure 3.3: Results of the question regarding the type of fast charging connector of the vehicle.

Figure 3.4 illustrates that a major part of the use of fast charging stations is done when travelling long distances. However, nearly a quarter of the drivers who answered the survey, use them once a week or more. Then there is a 3 % that say their EV cannot fast charge and a 4 % who has never used one. These users will not be answering the following section.

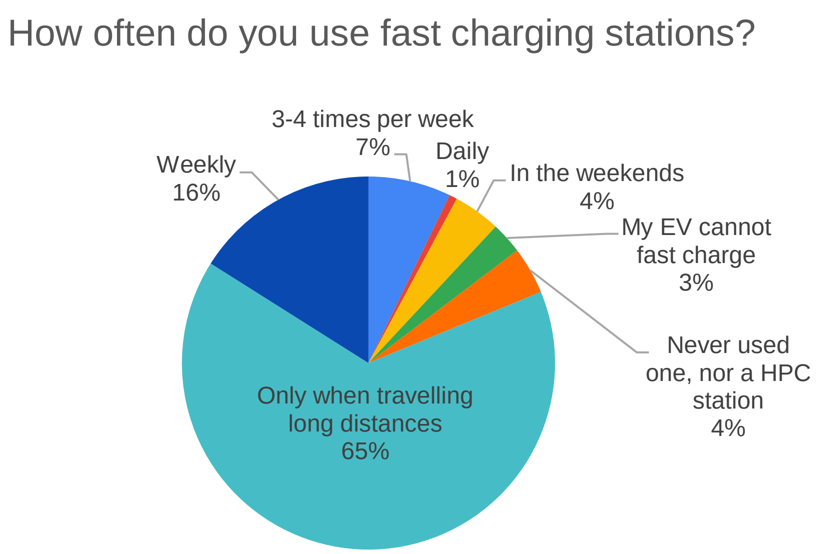

Figure 3.4: Results of the question regarding the frequency of use of fast charging stations.

Next four questions: section of use of fast charging stations (273 answers)

As it can be seen in Figure 3.5, more than a half of the survey respondents only use HPC stations when travelling long distances. A 10 % of them uses HPC at least once a week. It is interesting to point out that a 37 % of the drivers have never used one.

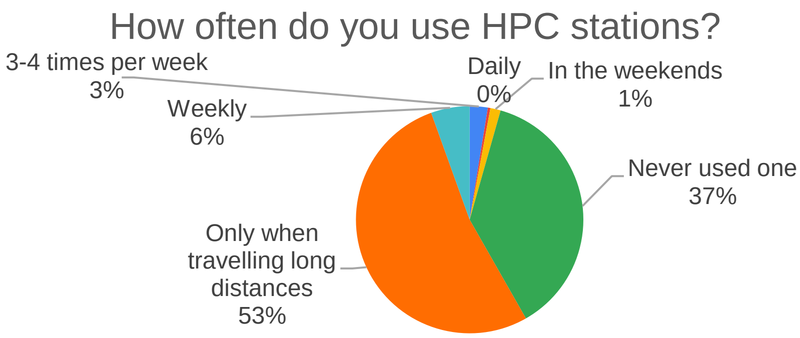

Figure 3.5: Results of the question regarding the frequency of use of HPC stations

The hour when the users polled mostly use HPC stations is seen in Figure 3.6. This result is not very reliable as this might change depending on the route and holidays. However, it can be extracted that the majority of them use it by midday and then there is a little peak by 18 h.

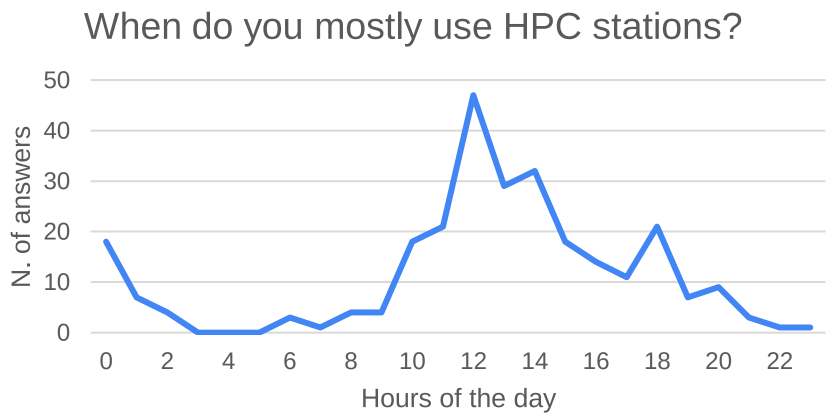

Figure 3.6: Results of the question regarding the time of use of HPC stations.

Figure 3.7 shows the mean State of Charge (SoC) of the battery when arriving to a HPC station. It is interesting to see that the majority of the answers are between 15 % and 27%, with a mean of 22,5 % because it shows that drivers will profit of a high charging power, which is achieved in lower SoCs.

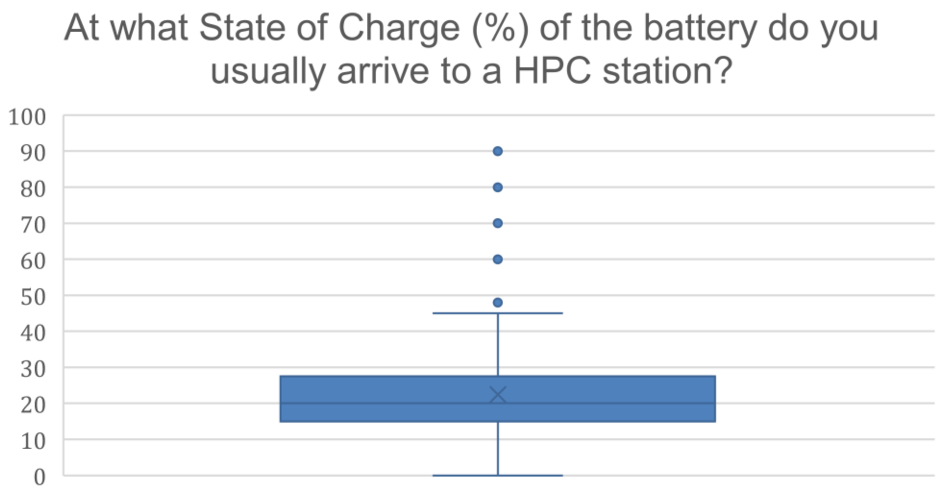

Figure 3.7: Results of the question related to the State of Charge of the battery when arriving to a HPC station.

The graph in Figure 3.8 shows the average fast charging power of the EVs the participants to the survey chose. The major part of the powers range between 45 and 130 kW. The mean is 77,6 kW.

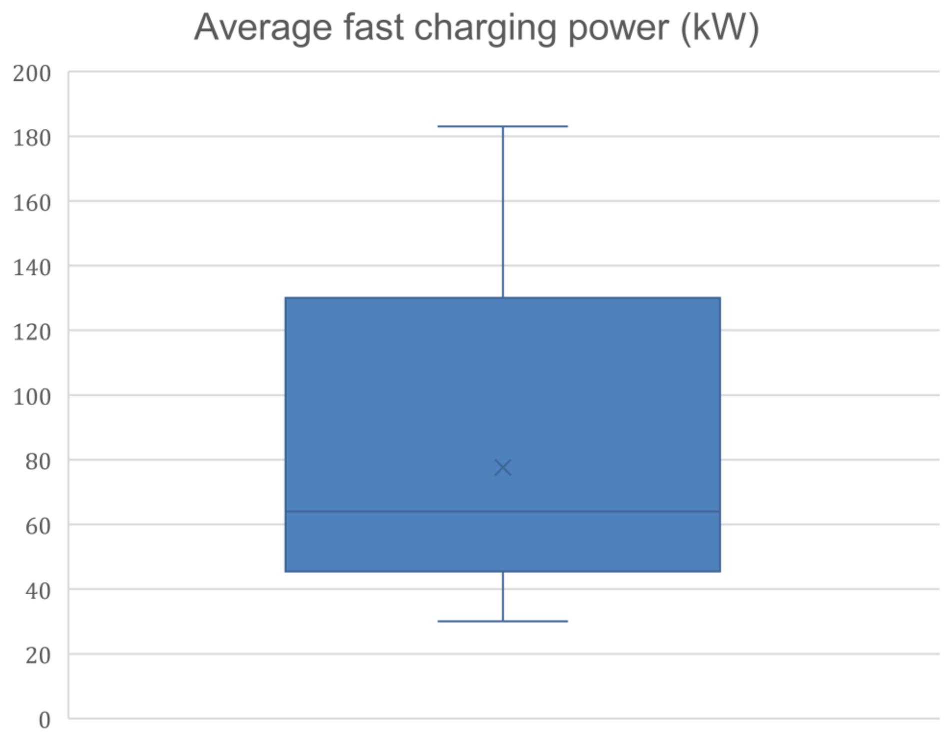

Figure 3.8: Average fast charging power based on the question regarding the model of EV the surveyed users have.

Section of use of fast charging stations ends

Figure 3.9 indicates the aspects the drivers surveyed value the most when using a HPC station. Depending on the preference they chose, a score was given. It results that the most voted is location and then availability followed by price. In number 4 the use of renewable energy sources, number 5 services available and finally in number 6, the less valued, the canopy covering the charging spots.

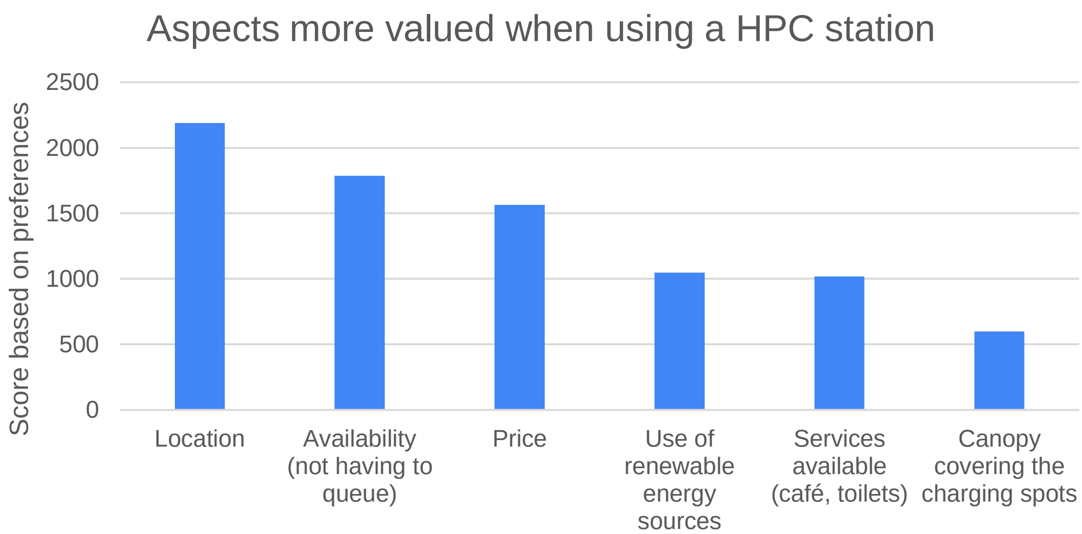

Figure 3.9: Results of the question regarding the aspects more valued when using a HPC station.

As Figure 3.10 indicates, nearly all the drivers would prefer charging in a renewable energy powered HPC station if they had the opportunity to do it.

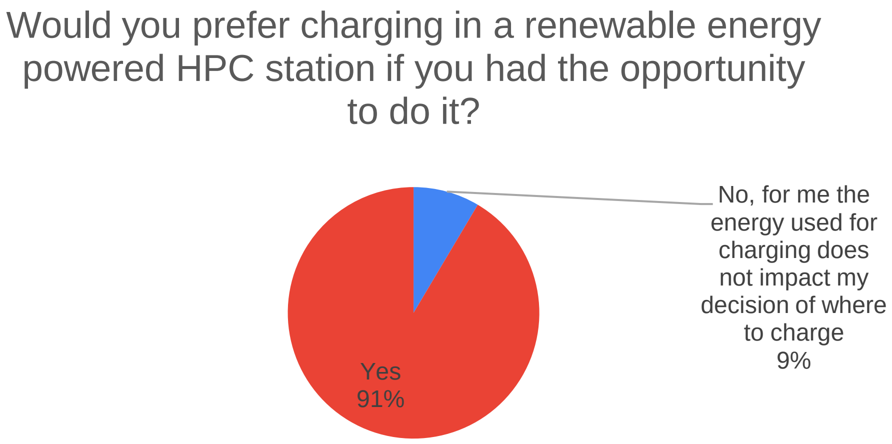

Figure 3.10: Results of the question regarding the preference of charging in a RE powered HPC station.

The last questions the users polled had to answer was if a canopy covering the charging area would impact the decision on where to fast charge. As seen in Figure 3.11, one third of the drivers say it is always important to have the car covered and another third states that only when it rains or snows. Finally, the remaining 30 % of them say the canopy is not important when charging.

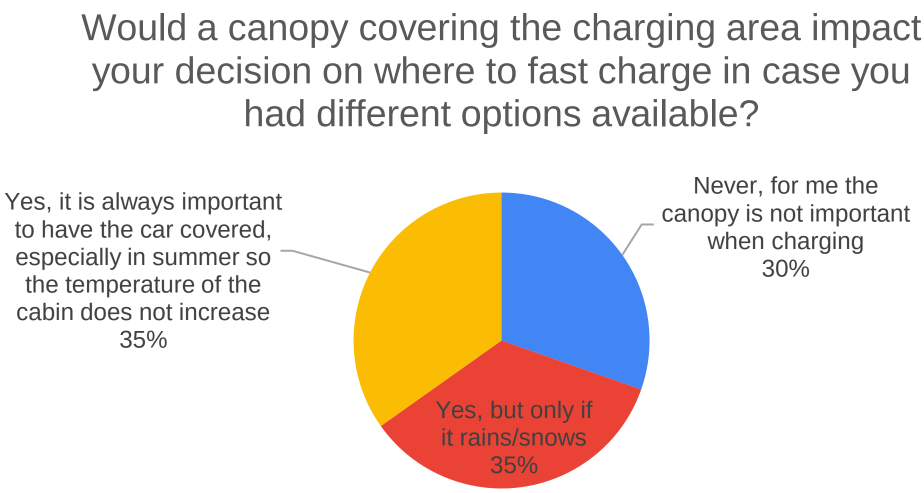

Figure 3.11: Results of the survey regarding the importance of a canopy when fast charging.

To sum up, the survey verifies the hypothesis that drivers prefer charging in a RE powered HPC and that more the half of them only uses these stations for travelling long-distances.

4. DESCRIPTION OF THE SOFTWARE USED

After trying different programs to simulate the energy system, the HOMER software was chosen. Originally developed at the National Renewable Energy Laboratory (NREL) of the United States, HOMER software provides insight into the complexities and trade-offs of designing cost effective, reliable microgrids, driving informed decision making so the design of systems with confidence. The advantages of the program are the following.

- Simulates real-world performance and delivers an optimized design.
- Quickly and efficiently determines least-cost options.
- Combines engineering and economics in one powerful model.

This software has two different programs HOMER Pro and HOMER Grid. HOMER Pro is made for modelling distributed generation. Its primary focus is on microgrids or multi-generator island or village utilities, but it can also model unreliable grids, grid extension, and a broad array of control strategies. HOMER Grid is designed to meet an increasingly important modelling challenge that is not handled by HOMER Pro: minimizing demand and time of use charges for Behind-The-Meter projects, from solar plus storage to more complex systems including wind, backup generators, and combined heat and power [10].

4.1. Setup and economics

The first step to start with the modelling is entering a location so the program knows where to download data. The location can be specified with geo coordinates. Then the economic parameters of the discount and inflation rates as well as the project lifetime are set.

4.2. Electric load – Electric Vehicle charging

An electric load can be imported from a file or modelled with some specifications. In HOMER Pro it is possible to choose the bus where the load will be connected: AC or DC. Then, there is a very useful module in HOMER Grid about EV charging. After setting the number of chargers and the maximum power they can deliver, the charging sessions can be modelled. This is done by inputting the different types of EVs with their percentage of population, their maximum charging power and the charging duration.

The daily number of sessions hour-by-hour can be modified per month and differing from weekdays and weekends. Then, a variability of the charging duration, energy delivered, day-to-day and time-step can also be entered. Based on these variations, the exact minute the car arrives will be assigned randomly within the specified hour. Moreover, for every specified session, a random electric vehicle will be drawn from the EV population inputs. [11].

4.3. Utility

The detailed tariffs of the electric utilities can be entered. These can be chosen from the database (for US and Canada), built by entering simple rates or inserted from the tariff library. In this case, the detailed model can be input with all the specific rates of demand and consumption. The detail can go as far as with different hourly rates for every month and if there are different rates per hours, an external file can be imported. Furthermore, the taxes can be set as well as the holidays, which are important to consider because the rates are then different than from a weekday.

4.4. Data for Renewable Energy resources

The program allows to enter different types of energy resources: Global Horizontal Irradiance (GHI), PV production, temperature, fuels and wind speed.
The resources can either be downloaded from the Internet in the same program (data from NASA) or imported in a csv file. When there are downloaded values in the monthly solar radiation table, HOMER builds a set of 8760 solar radiation values, or one for each hour of the year. HOMER creates the synthesized values using the Graham algorithm, which results in a data sequence that has realistic day-to-day and hour-to-hour variability and auto-correlation [12]. On the other hand, an imported file can have a time step from 1 hour to 1 minute.

4.5. Components

After inputting the energy resources, the components, that are the hardware used to transform energy resources to electricity can be entered. These are the solar panels, the wind turbines, the storage, the converter, and the generator. They can be chosen from a catalogue with the different capacities available in the market. The cost for the components can be entered distinguishing between the CAPEX, the cost of replacement after a specified lifetime, and the O&M costs. However, the power dimension that the program uses for the simulation does not have to be the one of the chosen components. Instead, the actual size used in the simulation can either be specified by the user or the HOMER Optimizer can be allowed to select the optimal size.

4.6. Results

HOMER calculates the most optimal solution based on the Net Present Cost (NPC), with cash flow calculations. Apart from viewing the most optimal system, the other combinations with the different components entered can also be seen in a table. The results are displayed in several ways, such as the aforementioned table, which contains the architecture chosen, the cost of the system, a comparison of the economics and then the characteristics of each component like the capital cost, the production and the O&M cost. For each tariff of the utility there is the demand and energy cost, and the energy purchased and sold.

The HOMER program also provides several simulation details, in different tabs that include graphs where many details can be seen for example the cost summary, the cash flow or the electrical production and consumption. Furthermore, a time series plot is displayed with detailed information regarding the hourly energy consumption and energy supply. From there, different loads and resources can be shown.

Finally, an optimization report can also be created by HOMER. This one, compares different system categories for a sensitivity.

5. MODELLING

In the following section, the locations chosen for the case studies are specified. Then, the charging profile model used for the load is explained, as well as the detail of the grid utilities in both countries. The origin and treatment of the energy resources data is described too. Next, both the technical and economic aspects of the components used, such as PV panels or wind turbines are detailed. Finally, the economics of the model are stated.

5.1. Locations chosen

For each country, a HPC station has been chosen to apply the model. In the case of Spain, the two IONITY Briviesca stations that are currently under construction have been selected because they will have a high traffic in the route Madrid-Bilbao-French border at the AP-1 highway. There is one station on each side of the highway, at the State-owned service areas. The surrounding fields seem good for installing a PV plant. Figure 5.1 shows the location of both stations. They are located 281 km from Madrid and 116 km from Bilbao. 130 km South of Briviesca, in the same highway to Madrid, the IONITY Milagros station is already installed and will be in operation soon.

Figure 5.1: Location of the IONITY Briviesca stations [13].

Regarding Sweden, the IONITY Spekeröd station that is already in operation has been chosen due to its good location at the E6 highway, close to Gothenburg (42 km) when coming from Oslo, Norway (251 km). This route can be done hassle free by an EV, charging here, 118 km North in IONITY Strömstad and 64 km South of Oslo in IONITY Rygge. The station studied in Spekeröd is located at the Circle K station and has a drive through access with 4 Tritium 350 kW chargers installed and 8 more parking spaces prepared for future expansion. Figure 5.2 shows the location of the station.

Figure 5.2: Location of the IONITY Spekeröd station [14]

5.2. Electric Vehicle chargers profile model

EVs are currently in the early stage of the market but trends suggest that they may eventually replace conventional ICE vehicles almost completely. Of course, in some markets like Norway, the Netherlands, Sweden, or Germany it is already growing very fast while in others like Spain or Greece the growth is still slow. However, for this study it does not make sense to pick up the current EV charging profile because, firstly, the number of sessions per day are still very low and, secondly, the charging power of cars and battery capacity will be increasing in the coming years. Therefore, a single forecast of the charging profiles for 2025 is done for both stations.

6 chargers of 350 kW of output power were considered for all the simulations, as it is the standard IONITY currently has.

The charging profile consists of two parts: The first is the number of sessions per hour, day and month of the year. The second is a description of the charging session itself, with the energy delivered, and the charging power as a function of time. Even if these last three parameters are related to each other, they all need to be described to be able to simulate the charging sessions.

- Charging power is important for demand calculations both from grid and from the RE installation.
- Time is vital to see if cars do queue.
- Energy is key for consumption calculations and like how much RE is needed.

Consequently, the data was forecasted considering different sources: the hourly distribution of sessions at Fastned stations [15] and the charging time and power of different EVs from EVdatabase.org [16].

The HPC capable car population that can be observed in Table 5.1 was considered for 2025. The electric urban vehicles are not considered, nor the commercial ones. Trucks and buses have not been considered as for the moment IONITY does not have plans for them. The average fast charging power has been considered instead of the maximum because the probability that 6 cars enter a HPC station in a low SoC that enables them to charge at their peak power is low. Another reason is that this maximum power is usually achieved in only some minutes and the time step of the program is of 15 minutes. All data is from EVdatabase.org except the grey-shaded which is predicted. The duration of a charging session from 25 % to 80 % is considered because of the survey results, adapting the value of EVdatabase.org which is from 10 % to 80 % and estimating the time for the other cases.

Table 5.1: Average fast charging power of the HPC capable population forecasted for 2025.

Car model	Avg fast charging power (kW) 10-80 %	Weighing	Battery usable capacity (kWh)	Duration (min)	Energy charged (kWh)
Porsche Taycan	183	1 %	83,7	15	45,75
Audi e-tron GT	175	2 %	85	13	37,92
Mercedes EQS	150	2 %	107,8	20	50,00
Kia EV6	185	5 %	77,4	15	46,25
Hyundai IONIQ 5	140	10 %	72,6	15	35,00
VW ID.5	150	15 %	60	20	42,00
Nissan Ariya	90	10 %	63	25	37,50
Peugeot xxx	100	15 %	60	25	41,67
Tesla Model Y	170	17 %	72,5	18	50,75
BMW i4	120	5 %	80	20	40,00
VW ID.3	78	18 %	58	24	31,20
TOTAL		**100 %**			

Therefore, the weighted average charging power and energy charged are of 127 kW and 40,57 kWh respectively.

Then, having the percentage of charging sessions per hour from Fastned, 68 sessions per weekday and 100 per weekend day were input for 2025 after calculating the optimal number for 6 chargers in the station. As for the economics results, a 20-year project lifetime is considered, the number of charging sessions per day is forecasted on a long-term scenario. In Spain, the market is still in the early adopter phase so the probability of reaching 68 sessions/weekday in 2025 is very low, even though for 2035 it might be realistic.

It has to be added that the Fastned distribution of charging sessions was slightly modified for all weekends and August, because people travel more during these periods.

In Figure 5.3 it can be seen that the data collected from the survey does not differ that much compared to the one of Fastned. In general, it seems that a survey is perhaps not a good way of determining a charging profile, as the respondents seem to assume a more concentrated charging behaviour than the data from Fastned suggest. Especially many users say that they will charge in weekends at 12 h and in weekdays at 18 h, but data suggests it is much more spread out in time.

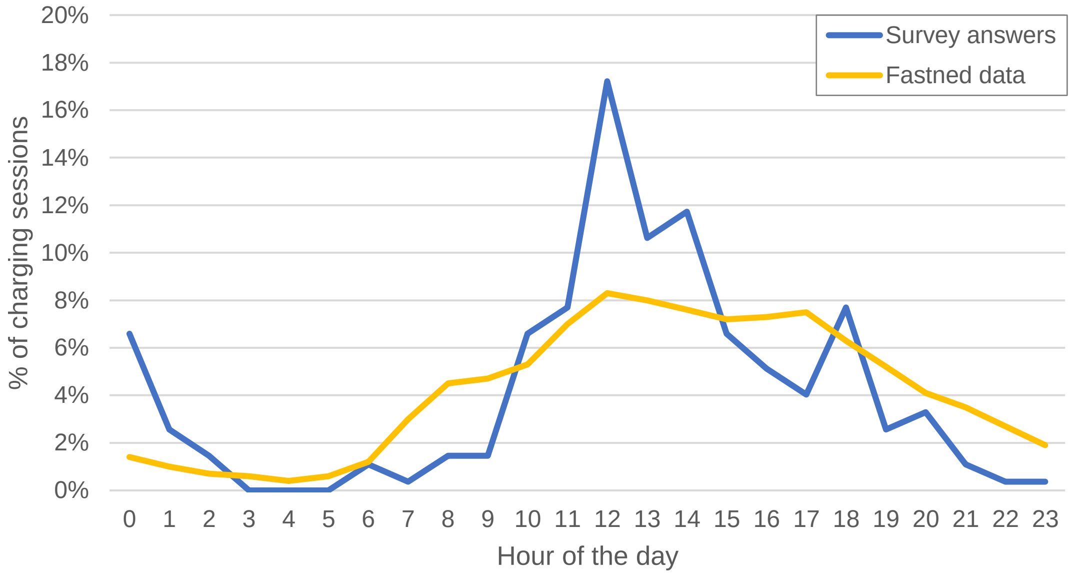

Figure 5.3: Charging sessions per hour comparison of Fastned data with the survey answers.

Then in Figure 5.4 the average number of sessions per hour in weekdays and weekends including August can be observed.

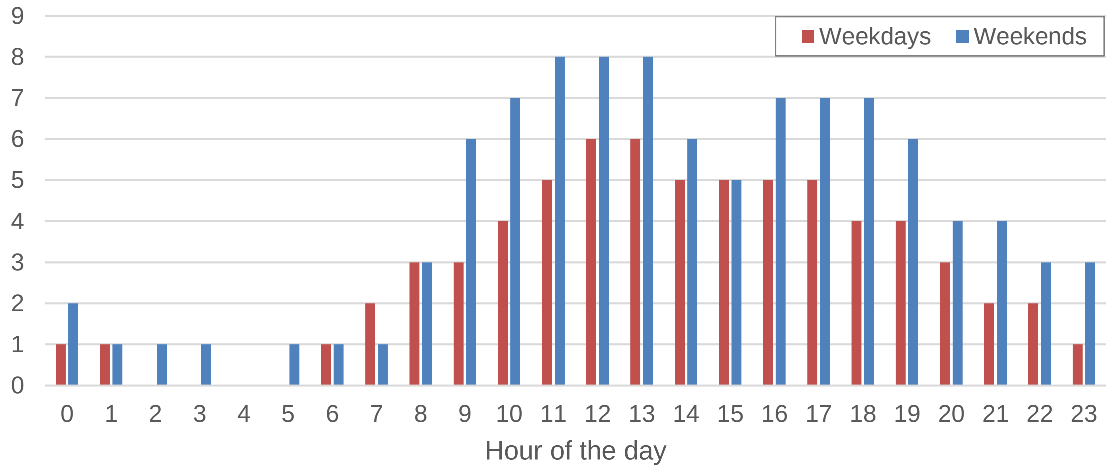

Figure 5.4: Average number of charging sessions per hour in weekdays and weekends including August. This profile has been used for both stations.

Finally, the car models with their population weighing, the average charging power and the charging duration were entered in the EV Charging module of HOMER. A variability of 20 % was set for charging duration and day-to-day. A 10 % timestep variability was also entered. These values are the ones HOMER has as default.

5.3. Utilities setting

The utility demand and consumption rates are stated below for each country. Since the boom of renewables some years ago the national electric systems are starting to allow to sell the produced electricity to the grid. For this reason, both countries studied have different systems to have revenues from the grid and they will be considered as they play an important role for the cost-effectiveness of the solution.

5.3.1. Utility in Spain

In Spain electrical tariffs are the same in all parts of the mainland. From the 1st of June 2021, for MV connections between 1 kV and 36 kV tariff 6.1TD applies. This will be the one considered in the model because for a HPC station there is usually the need of an MV connection, as Low Voltage (LV) ones are usually only used for connections of a maximum of 100 kW in Spain.

Tariff 6.1TD has 6 different periods both for power and energy fees that change every hour and month of the year as it can be later seen in Figure 5.5. P1 is the most expensive period whereas P6 is the most economic one. This runs always during night (00-08 h), weekends and national holidays [17].

In Table 5.2 the prices of the 6.1TD tariff are shown. All the tolls and charges are included as well as the commercial part for the energy fee, that depends on the selected company. In this case the prices of Som Energia [17] are used as it is one of the only companies that publish the prices for this 6.1TD rate. The monthly power fee is a fixed charge related to the power contracted while the energy fee varies.

Table 5.2: Power and energy fees for the Spanish 6.1TD tariff of Som Energia

Period	Monthly power fee [€/kW]	Energy fee [€/kWh]
P1	2,50979137	0,135
P2	2,128331918	0,119
P3	1,225409507	0,099
P4	0,994064301	0,085
P5	0,323725479	0,073
P6	0,173317233	0,069

For EV public charging points, in June 2021 a new tariff (6.1 TDVE) will be implemented [18] that lowers the power fee and increases a bit the energy fee. As this new tariff will last until 2023 to incentivise the installation of fast and HPC points, it is not considered for the results in the forecasted horizon: 2025-2045.

Regarding the remuneration fees for electricity production, the price that Som Energia has published in its website for the 6.1TD tariff [17] will be used that is of 0,051 €/kWh.

Then a 5,11 % electricity tax should be included as well as the general 21 % VAT tax (IVA). However, as other elements have been entered without taxes, these are not input to the program.

These rates have been entered into the program thanks to the Advanced Builder of the Utility Tariff Library. For the demand, in Spain the power needs to be contracted before and cannot be changed in a year. In tariff 6.1TD a different power for each period can be contracted as long as the following equation is true: P1<=P2<=P3<=P4<=P5<=P6. Therefore, as P6 runs on weekends and national holidays, when most travel is done, an increased power is contracted for this period. This is the reason why in the Spanish results two values for the contracted power can be seen: the first represents the power from P1 to P5 and the second the one of P6. The Spanish holidays have also been entered in the model as well as the taxes. In Figure 5.5 the consumption rates of tariff 6.1TD input to

HOMER Pro can be seen. At HOMER Grid the same thing was done but with a bit different interface.

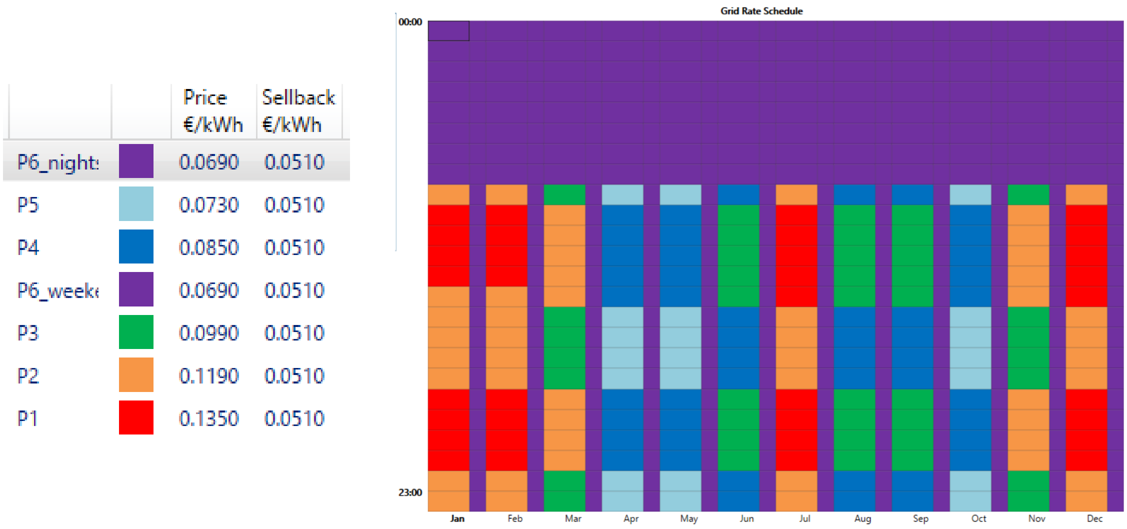

Figure 5.5: Consumption rates during a year for Spain in the 6 different periods

5.3.2. Utility in Sweden

Sweden has a different system for the distribution charges and for the energy ones. In the first case it depends on the location of the connection if it is in the North or the South. The southern zone is considered as it is the most populated one and the one where the case study station is located.

According to Vattenfall Eldistribution AB [19] for a High Voltage (HV) tariff like N3 in the Southern area of Sweden, the components of the electricity bill are the ones stated in Table 5.3.

Table 5.3: Distribution fees for the N3 tariff of Vattenfall Eldistribution AB

Component	**Cost in SEK**	**Cost in €[3]**
Fixed charge	2.400 SEK per month	235,83 € per month
Power ‘normal’ fee	27 SEK/kW per month	2,65 €/kW per month
Power ‘winter’* fee	55 SEK/kW per month	5,4 €/kW per month
Transmission ‘winter’* fee	0,189 SEK/kWh	0,0186 €/kWh
Transmission ‘normal’ fee	0,066 SEK/kWh	0,0065 €/kWh

**‘Winter’ fee: weekdays (except when public holiday) from 6 to 22 h during the months of January, February, March, November and December.*

Then, for having the energy price, the hourly price needs to be added as well as the tax. The hourly price is determined by Nord Pool Group and varies from hour to hour depending on the demand and supply that hour. For the stations in Sweden the zone SE3 will be considered as it is the one of Gothenburg and the Spekeröd station, see Figure 5.6. There is also a supplemental surcharge of the grid company of 0,0078 SEK/kWh (0,00077 €/kWh[3]). Then a 0,356 kr/kWh (0,0348 €/kWh[3]) tax of Skatteverket (Swedish Tax Agency) needs to be added.

[3] Exchange rate: 1 € = 10,176 SEK, 26/03/2021

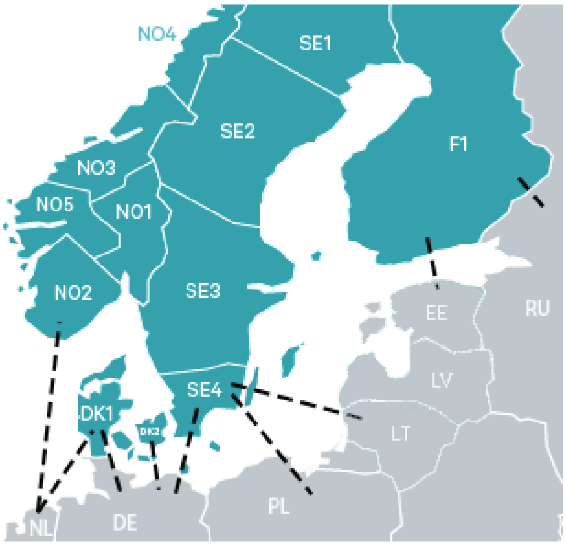

Figure 5.6: Different areas of the Nord Pool market

According to Vattenfall Eldistribution [20][4], the reimbursement for own electricity production (when producing less than used in a calendar year) for HV connections in the South of Sweden is as follows in Table 5.4. Finally, the general 20 % VAT should be added, but as it is explained in the case of Spain, it is not considered.

Table 5.4: Reimbursements for electricity production in Sweden

Component	**Revenue in SEK**	**Revenue in €[3]**
Energy compensation 'winter'* time	0,10 SEK/kWh	0,01 €/kWh
Energy compensation other time	0,028 SEK/kWh	0,0027 €/kWh

**'Winter' fee: weekdays (except when public holiday) from 6 to 22 h during the months of January, February, March, November and December.*

All these fees have been added to the Tariff Builder of HOMER Grid. The hourly energy price of 2020 has been downloaded from Nord Pool website [21] and input it to the program. In Figure 5.7 the distribution of the different rates for demand can be seen. There is no graph for the energy tariff as it varies hourly.

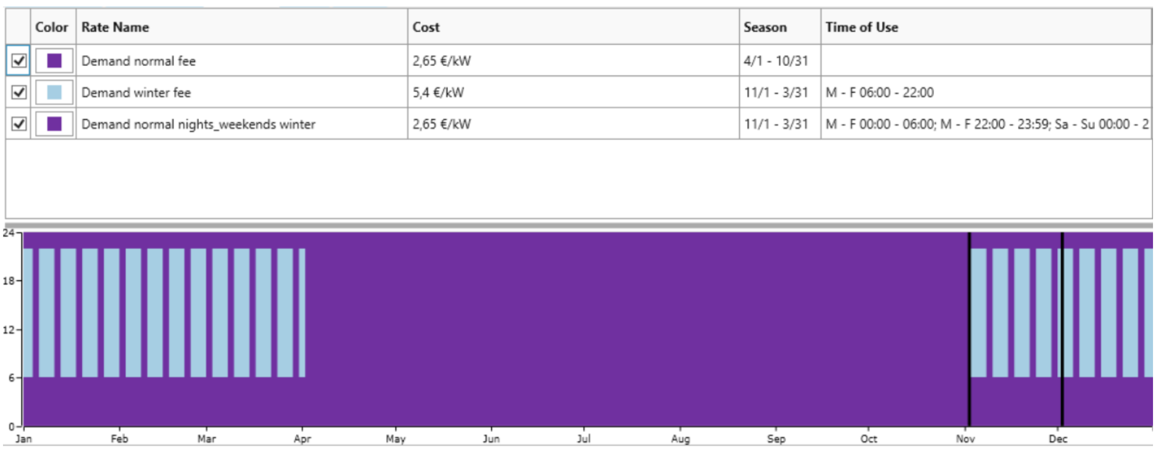

Figure 5.7: Distribution of the different rates for demand during a year in Sweden

[4] The terms presuppose that the customer is a withdrawal customer. This means that the main purpose of the customer facility is something other than production, e.g. residential, agricultural or industrial.

5.4. Renewable energy resources of the model

Solar and wind resources are input to the model to allow the optimizer to use solar PV and wind power for the solution.

5.4.1. Solar resource

Regarding solar resource in Spain, it has been entered data of the hourly production mean. This has been downloaded from the PVGIS website of the European Commission, that seems to be the most reliable source for it. This data already takes into account the effect of clouds as it is based on satellite images which are used to identify the presence and the thickness of clouds [22]. Concretely, the PV production hourly values from 2005 to 2016 of a 1200 kWp plant with 14 % system losses [22] have been downloaded from the PVGIS-SARAH database for Briviesca location. Then the mean of the 12 years has been calculated and imported to HOMER.

The data used for the solar resource in the simulations done for Sweden are directly the PV production patterns of a large PV installation that Göteborg Energi has within its operational area. It is important to highlight that thanks to this approach the results are much more realistic because it already considers variables that could interfere with the solar irradiation data such as snow covering the panels and shadows. As Gothenburg is at 42 km South from Spekeröd, the values are considered valid to use for the station.
The "raw data" consists of the percentage of PV production in a 15-minute time step from May 2019 to February 2021. As the program only accepts 1 year of data it has only been considered the 2020 15-min production and the pattern in this interval has been imported to HOMER.

5.4.2. Wind resource

For wind speeds, the same approach has been considered for both countries. The Typical Meteorological Year (TMY) values of the hourly wind speed at 10 m from 2007 to 2016 have been downloaded from the PVGIS website of the European Commission. Then it has been imported to HOMER.

5.5. Components of the model

The components considered for a possible solution are PV panels, wind turbines, battery storage and a converter for the DC-AC bus.

5.5.1. Photovoltaic panels

As the PV production data is directly imported, the program does not consider the technical data of the panels. However, when downloading the data from PVGIS for the Spanish station, the following parameters were set or calculated by the European Commission tool.

- Mounting type: fixed
- Optimized slope and azimuth: 35° and 3° respectively
- PV technology: Crystalline silicon
- System loss: 14 %

For Sweden, the details of the Göteborg Energi installation are unknown, except that the angle is of 30°.

The Imported PV production is linked to the AC bus as the production data already considers the inverter.

Regarding the costs, these have been considered for 2025, the same year of the chargers' profile forecast. According to IRENA [23], solar PV installation costs would continue to decline dramatically in the next three decades, averaging in the range of 340 to 834 USD/kW by 2030, compared to the average of 1210 USD/kW in 2018. Therefore, a price of 700 USD/kW has been set for 2025, which is 579 €/kW[5]. Concerning the replacement, this will be done every 25 years and is forecasted in an 80 % of the total installation cost: 463,2 €/kW. Finally, the O&M costs for Europe were of 9 USD/kW and year for 2017 according to IRENA [24], with a reduction of a 17 % every doubling of the capacity. In 2025 the capacity is expected to grow 30 % in Europe [23] so the costs will approximately be reduced by 10 % to 8,1 USD/kW and year (6,7 €/kW[5] and year).

5.5.2. Wind turbines

In this case, as the wind speed is entered, the different types of wind turbines need to be chosen. The 100 kW wind turbine model of Norvento and the 250 kW model of WES were chosen as they where found to be the most suitable solutions after simulating with other type of wind turbines. In Table 5.5 the details of each wind turbine can be seen.

Table 5.5: Details of the two wind turbines considered in the simulations. Norvento [25] and WES [26]

Manufacturer	Norvento Enerxia	Wind Energy Solutions
Model	nED100	WES250
Capacity	100 kW	250 kW
Type	3 bladed	2 bladed
Rotor diameter	24 m	30 m
Cut in, out wind speed	3 m/s, 20 m/s	< 3 m/s, 25 m/s

Regarding the costs, these have been considered for 2025, the same year of the chargers profile forecast. According to IRENA [25], globally, the total installation cost of onshore wind projects would continue to decline dramatically in the next three decades, averaging in the range of 800 to 1350 USD/kW by 2030, compared to the average of 1497 USD/kW in 2018. Therefore, it has been set a price of 1200 USD/kW for 2025 that is 992 €/kW[5]. Concerning the replacement, this will be done every 20 years and is forecasted in an 80 % of the total installation cost: 794 €/kW. Finally, the O&M costs are forecasted at 30 USD/kW and year (24,8 €/kW[5] and year) according to the tendency that IRENA indicates in [24].

5.5.3. Battery storage

The generic modules of Lithium-Ion (Li-ion) batteries of 100 kWh and 1 MWh have been considered for both models. They have a nominal voltage of 600 V, a roundtrip efficiency of 90 % and the minimum SoC is set at 20 % to preserve the battery life. The maximum charge and discharge currents for the 100 kWh pack are of 167 A and 500 A respectively, whereas the ones of the 1 MWh one are the same multiplied by 10. Even though these rates are limited by the converter capacity set.

[5] Exchange rate: 1 € = 1,209 USD $, 24/04/2021

Regarding the costs, these have been considered for 2025, the same year of the chargers profile forecast. According to IRENA [26], globally, the total installation cost of Li-ion BESS will be lower than 500 USD/kWh in 2030. Therefore, it has been set a price of 600 USD/kWh for 2025 that is 495 €/kWh[5]. Concerning the replacement, this will be done every 15 years and is forecasted in an 80 % of the total installation cost: 396 €/kWh. Finally, the O&M costs are forecasted at 10 USD/kW and year (8,27 €/kWh[5] and year) according to [27].

5.5.4. Converter

A converter is needed when considering storage as this is plugged in DC and the rest of the loads to AC. The default system converter with an inverter and rectifier efficiency of 95 % is considered for the simulations.

Related to costs, the CAPEX, has been set to 90 USD/kW [28] (74,3 €/kW[5]) and the replacement to 80 % of the acquisition one: 59,44 € every 15 years. No O&M costs have been set for the converter.

5.6. Overview of the costs per technology

In Table 5.6 an estimation of the costs per technology in 2025 can be seen.

Table 5.6: Overview of the different costs and lifetime of each component considered.

Component	CAPEX [€/kW]	Replacement [€/kW]	Lifetime [years]	O&M [/year]
Solar PV	579	463	25	6,7 €/kW
Wind	992	794	20	24,8 €/kW
Li-Ion Storage	495 €/kWh	396 €/kWh	15	8,27 €/kWh
Converter	74	59	15	-

5.7. Economics of the model

The default values of the program have been considered for the nominal discount and the expected inflation rates. Then HOMER calculates the interest rate (i) using equation (1). The project lifetime has been set to 20 years. In Table 5.7 these rates can be seen. For the system fixed capital cost, the transformer station CAPEX depending on the grid limit set will be added as it can be observed in Table 5.8.

$$i = \frac{i' - f}{1 + f} \tag{1}$$

Tables 5.7 and 5.8: Economical rates considered for the model and CAPEX of each transformer.

Nominal discount rate (i’)	8 %
Expected inflation rate (f)	2 %
Interest rate (i)	2 %
Project lifetime	20 years

Size of the transformer station	**1250 kVA**	**630 kVA**	**250 kVA**
System fixed capital cost	120.000 €	71.924 €	37.000 €

6. RESULTS

For both stations the results have been calculated depending on the available power capacity of the distribution grid. The grid size limit set, both for the grid purchases as for the sellback will depend first on the availability of power of the connection point and second on the size of the transformer connecting the station to the grid. For example, if a 1250 kVA transformer is installed, then the grid limit can be of 1200 kW, considering a cos(φ) of 0,96. The simulations have been done for a 1200 kW, 600 kW and 240 kW limits in MV and a case of a 100 kW LV connection has also been considered.

After having the results for each grid limit, it has been seen that it is generally more cost-effective to have a bigger grid connection even if an MV line needs to be built to reach a point in the grid with 1,2 MW of available power. Therefore, the results will only be detailed for the bigger grid connection. All the other results can be observed in a table to compare the alternative grid connection sizes.

Then a sensitivity analysis, with a fixed grid limit of 1,2 MW, has been conducted for each station depending on the number of average charging sessions per day: 38, 77 (nominal, considered for all the simulations) and 154. This result is significant as not all the HPC stations will have a 'stable in time' level of 77 sessions per day in a year. Depending on the location and other factors, it will change so the analysis is done to see if with the same grid connection, it is also cost-effective. Then, it is important to state that all these simulations have been also carried out with a project lifetime of 20 years. Thus, the intention of this sensitivity analysis is not to show if the electrical supply of the stations will be cost-effective in the short-term due to the low use of the chargers there is now in early EV markets as Spain. This would be a misinterpretation of the results because the EV market is growing, in some countries faster than others, but in a 20 year horizon the charging sessions will tend to be stable due to the capacity of the station. If cars need to queue, more chargers will be built and a bigger grid connection too.

6.1. Briviesca station (Spain)

The results of the simulations depend on the grid size limit set and on the possibility to sell energy back to the grid or not. This is considered in the Spanish simulation because there is an important government incentive (MOVES 3)[6] for the installation of RE feeding a charging station that is received only in RE systems that do not sell energy to the grid [29]. The results also differ with the charging sessions per day considered and this is why as mentioned in the introduction of the chapter a sensitivity analysis is conducted.

Then, the reason why the storage is not chosen as part of the system is also analysed in the last subsection.

6.1.1. Possible sellback in Briviesca, Spain

Table 6.1 shows the electric supply systems that seem to be optimal depending on the grid limit. The most cost-effective system, with the lowest NPC, is with the biggest grid limit: 1,2 MW. In this case, the benefit of installing a grid connected PV plant instead of just having all the energy from the utility is of 766.133 €, which is considerable. Then, it

[6] 35-60 % incentive depending on the size of the enterprise and municipality.

can be observed that when the grid limit decreases, it is usually more cost-effective to build an MV line to the 1,2 MW connection point than installing the storage needed. However, in the case of having a grid capacity of 600 kW and if the MV line to be built has more than 13 km, it is better to install the 2000 kWp plant with 200 kWh of storage. In Figure 6.1 a graphical representation of the results can be observed.

Table 6.1: Most cost-effective systems depending on the grid limit in Briviesca, Spain.

Grid limit	**1,2 MW**	**600 kW**	**240 kW**	**100 kW**
Contracted power	400/700 kW	400/600 kW	240 kW	100 kW
Solar PV	2500 kWp	2000 kWp	2356 kWp	2662 kWp
Wind	-	-	-	2x250 kW
BESS	-	200 kWh	3 MWh	4 MWh
NPC	1.171.662 €	1.483.313 €	3.696.455 €	5.063.238 €
NPC only utility	1.937.795 €	Not possible	Not possible	Not possible
NPC benefit compared to utility	766.133 €	-	-	-
Min km of MV line* to be cost-effective	-	13	101	156

**MV line to the 1,2 MW connection point, considering a cost of 25.000 €/km*

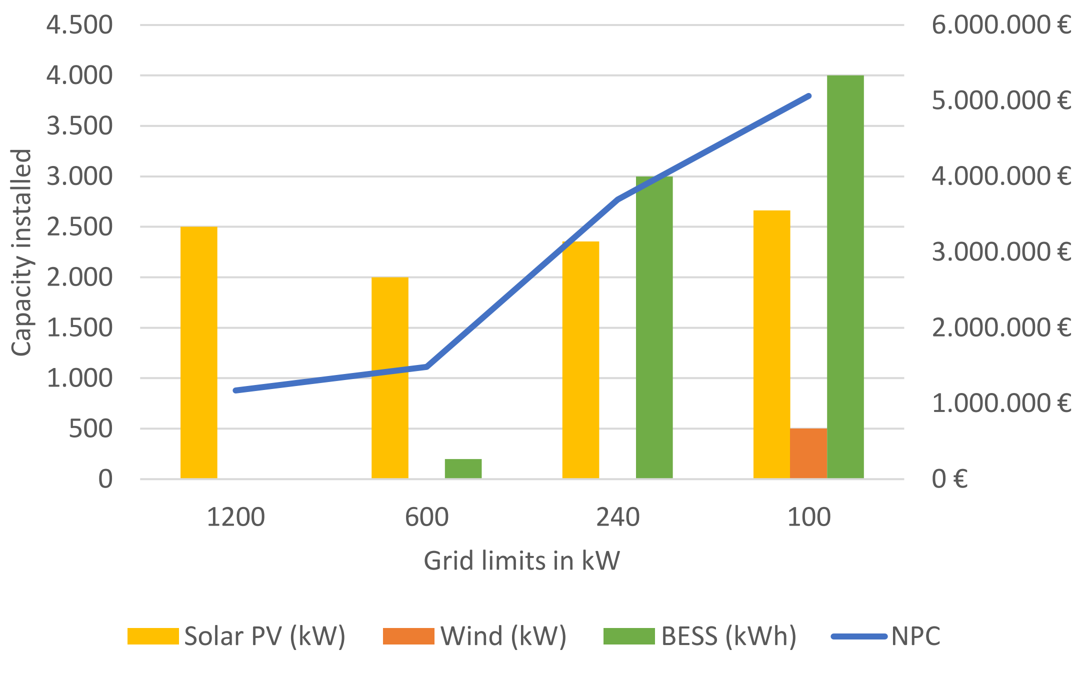

Figure 6.1: Electrical supply systems for the different grid limits in Briviesca, Spain

A detailed view of the most cost-effective system, the 1,2 MW grid limit with a 1250 kVA transformer installed and a 2500 kWp solar PV plant, can be seen in the following pages.

The most optimal solution for the 1200 kW grid connection with possibility to sell energy to the grid is a 2500 kWp solar PV plant. In Figure 6.2 the energy source of the chargers for this system can be observed. Two thirds of the energy used will come from the on-site PV solar plant, whereas the remaining energy will be purchased to the grid.

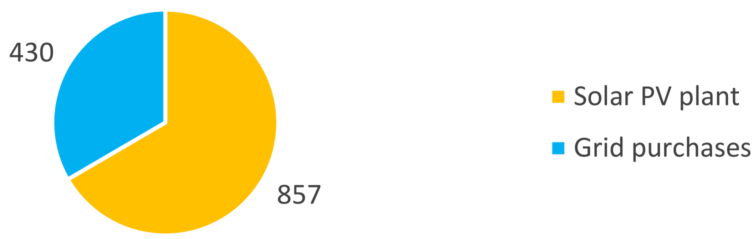

Figure 6.2: Energy source of the chargers for the 1,2 MW system in Briviesca, Spain

Figure 6.3 shows the monthly electric production. The irradiation curve is clearly seen, and it is interesting to point out that the utility purchases do not increase substantially in winter months. This is because the solar PV plant is oversized for the charging station and as it can be observed in Figure 6.4 even in low irradiance days during daylight there are no purchases from the grid. In the appendix B it can be seen that there is no month with grid purchases during central daylight hours. The oversizing is due to the profitability of selling energy to the grid. Therefore, it could be stated that this system can be described as a utility scale solar PV plant, with an integrated HPC station that profits of the 'free' solar energy as much as possible.

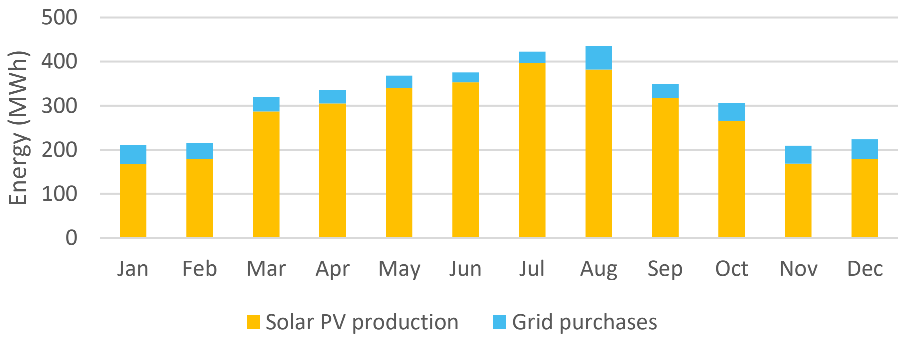

Figure 6.3: Monthly electric production for the 1,2 MW system in Briviesca, Spain

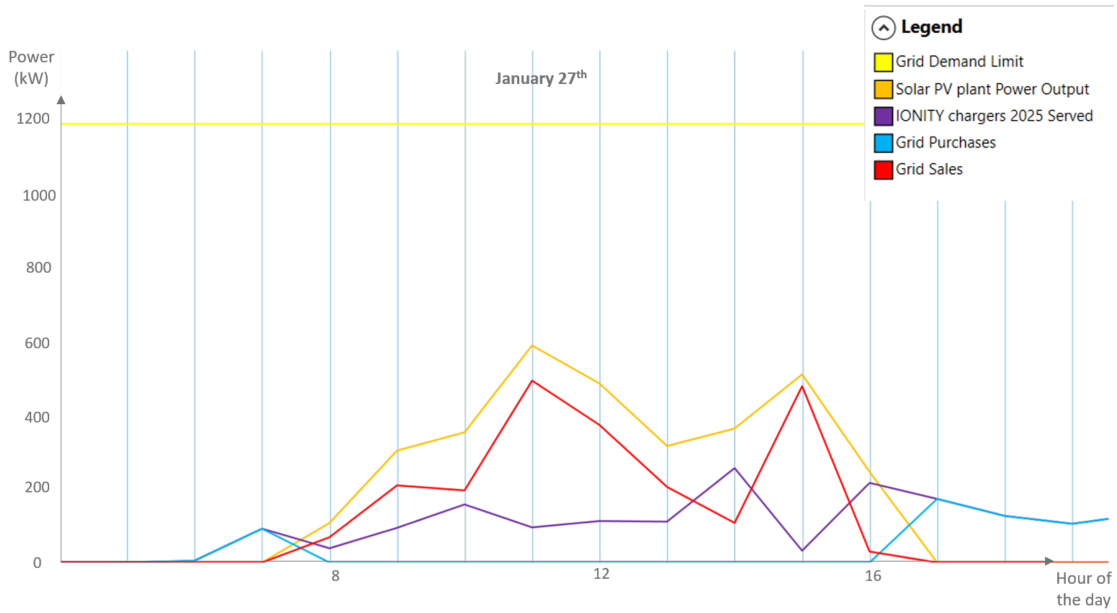

Figure 6.4: Hourly power graph of the different sources in a winter low PV production day for Briviesca, Spain.

The oversizing of the solar PV plant which was stated earlier can be very well observed in Figure 6.5 which shows the day with the highest consumption from the HPC station. Even in this case, grid sales are much higher than the energy delivered to the chargers. And in days when there are not a lot of cars charging during daytime, as seen in Figure 6.6, the grid sales are limited due to the 1,2 MW grid limit, 'wasting' some energy.

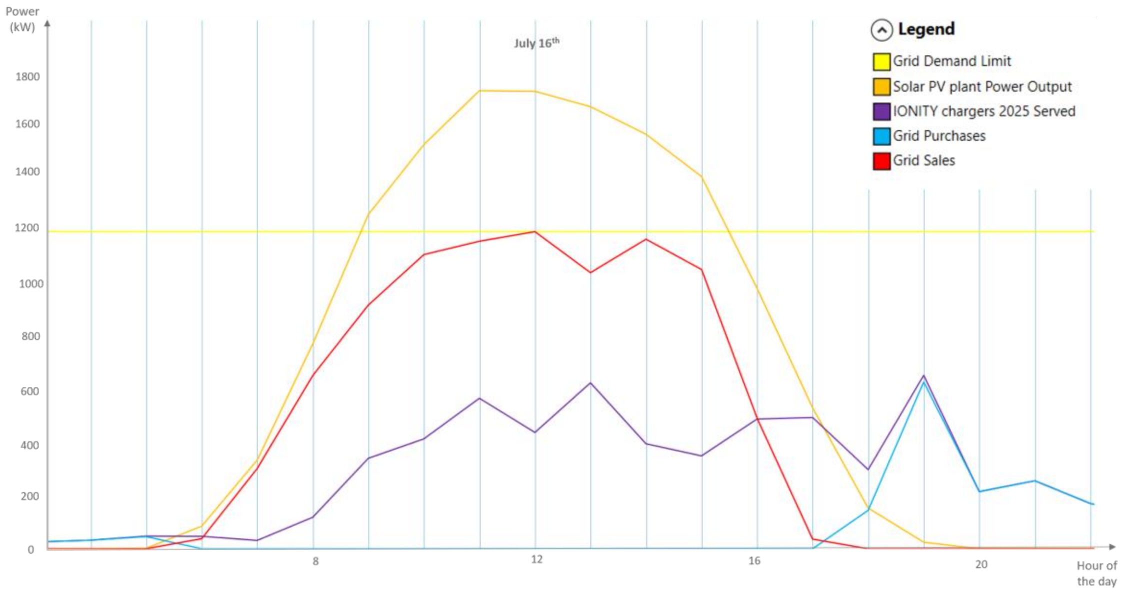

Figure 6.5: Hourly power graph of the different sources in a summer day with the highest consumption of the HPC station for Briviesca, Spain

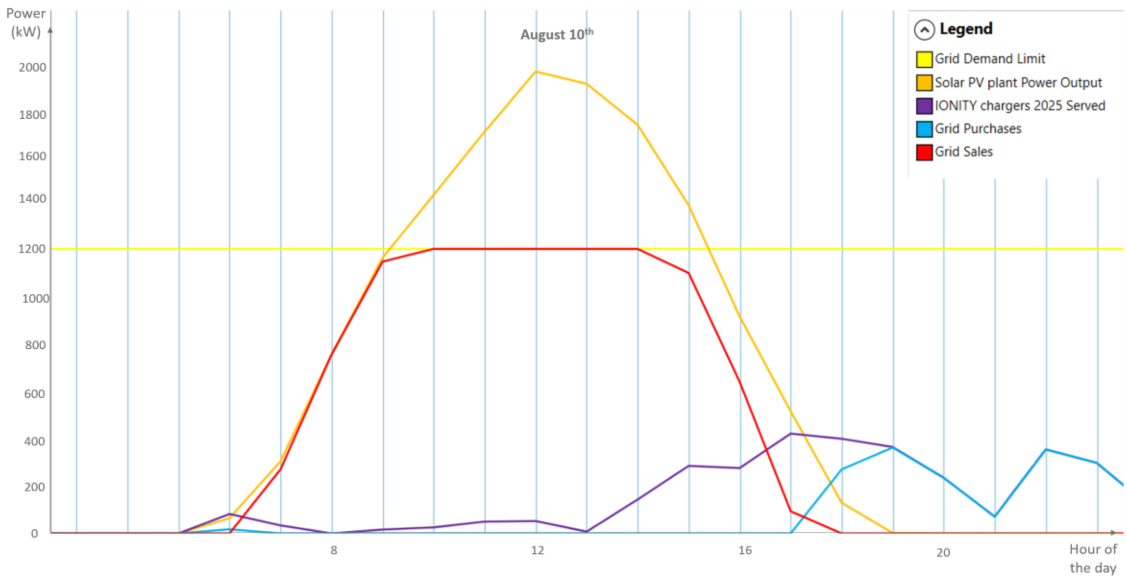

Figure 6.6: Hourly power graph of the different sources in a summer day with a low consumption of the HPC station during midday and thus high grid sales for Briviesca, Spain

In Figure 6.7, which shows the hourly energy produced and consumed during a year, the oversizing can also be very well noticed. It could be said that the grid limit of 1,2 MW is also oversized even though it is not the case. The reason why the IONITY consumption shown is much lower than the grid limit is the use of the hourly average charging power for the simulations, as it has been mentioned in section 5.2. If the maximum charging power was used, then the graph would show much higher peaks in the grid power. Moreover, as the time step for the Spanish simulation is 1 h, the differences of power on the 20 min mean charging sessions cannot be plotted. Then, Figure 6.8 shows that the grid sales could even be higher from March to October if the 1,2 MW grid limit would not exist.

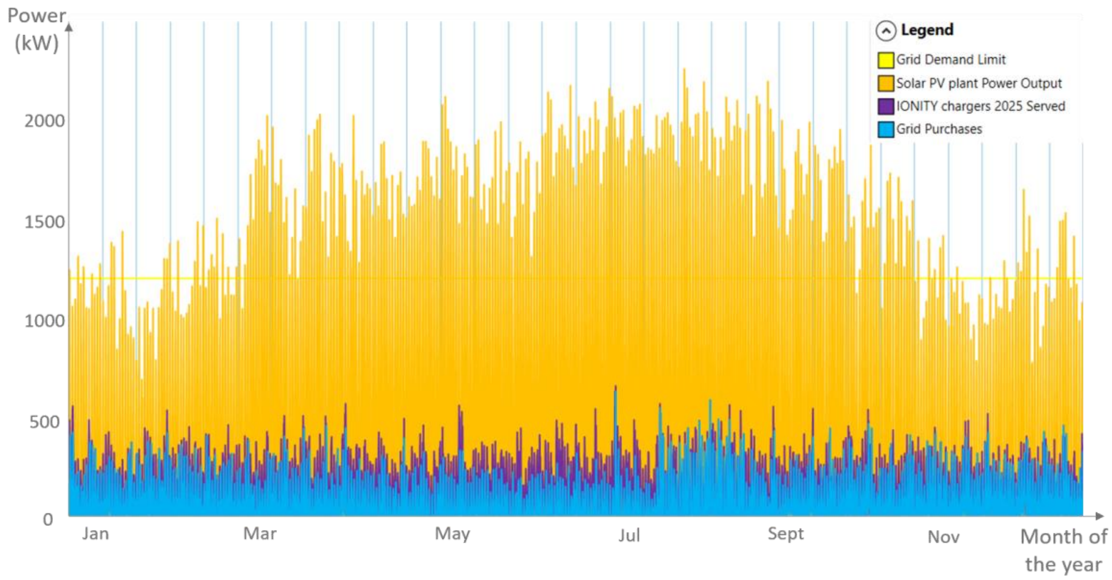

Figure 6.7: Hourly power graph of the different sources during the whole year for Briviesca, Spain.

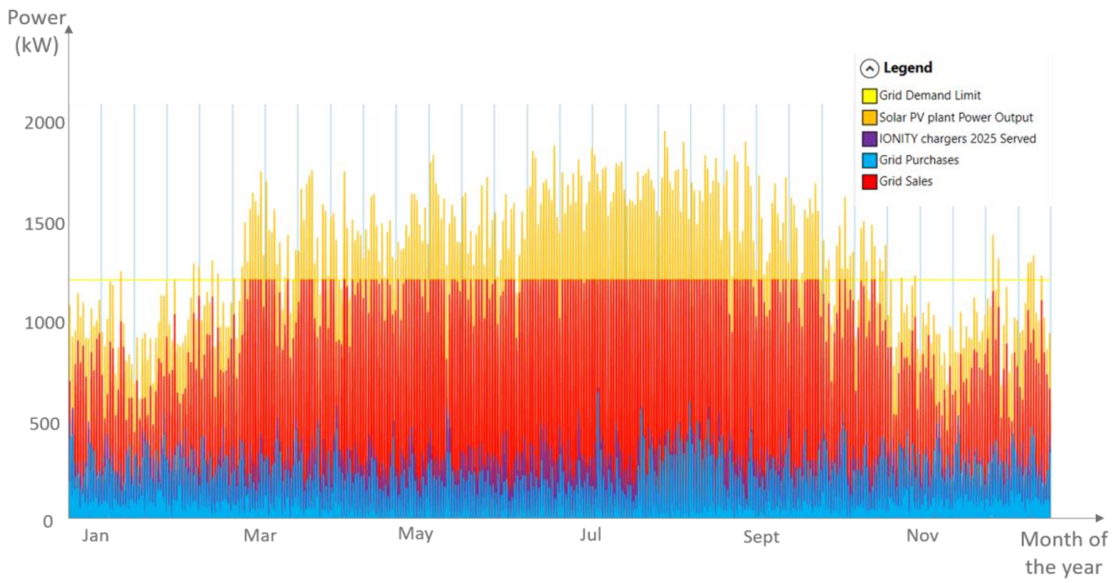

Figure 6.8: Hourly power graph of the different sources, including grid sales, during the whole year for Briviesca, Spain.

Regarding the economics, a summary can be seen in Table 6.2. It can be said that as the Internal Rate of Return (IRR) is greater than the interest rate (2 %) and the NPC is positive, the investment is profitable. The payback time is very good as it happens before the middle of the 20 years project lifetime. The Return on Investment (ROI) is similar to the top smart grid companies and higher than the top power companies [30].

Table 6.2: Economic metrics for the 1,2 MW system in Briviesca, Spain

Metric	Value
Internal rate of return (IRR)	11,5 %
Payback	7,83 years
Return on investment (ROI)	8,6 %

6.1.2. Sellback not possible in Briviesca, Spain

In this case, it is assumed to request the MOVES 3 plan, which gives an important incentive[6] for RE components that feed a charging station and does not allow selling energy to the grid. The most cost-effective system for each grid limit can be seen in Table 6.3. The system with the lowest NPC also presents the biggest grid connection, and it is 300.000 € higher than the one with possible sellback, because there are no revenues from grid sales. For this reason, even with the 40 % MOVES 3 incentives, the solar PV plant is much smaller. It could be said that for this system the solar PV plant is sized a bit bigger than the mean consumption because of the free energy available, whereas with possible sellback to the grid the PV plant is sized to sell energy to the grid and the HPC station profits of this free energy.

Regarding the other results for lower grid limits, the NPC increases due to the need of mainly storage and RE to compensate the lack of instantaneous power that the HPC station demands. However, it is interesting to see that for grid limits of 240 kW and 100 kW, it is more cost-effective not to sell energy and profit of the MOVES 3 plan than to sell it. Even though, as it has already been said, these cases are very rare to happen as it would be more cost-effective to build an MV line to the 1,2 MW connection point.

Table 6.3: Most cost-effective systems to meet the demand, when sellback is not possible, depending on the grid limit in Briviesca, Spain.

Grid limit	**1,2 MW**	**600 kW**	**240 kW**	**100 kW**
Contracted power	400/700 kW	400/600 kW	240 kW	100 kW
Solar PV	677 kWp	78 kWp	2541 kWp	2662 kWp
Wind	-	-	-	2x250 kW
BESS	-	100 kWh	3 MWh	4 MWh
NPC	1.473.144 €	1.800.850 €	2.913.878 €	3.456.421 €
NPC difference with possible sellback	301.482 €	317.537 €	- 782.577 €	- 1.606.817 €
Capital	355.219 €	150.473 €	1.941.699 €	2.558.952 €
Min km of MV line* to be cost-effective		14	58	80

**MV line to the 1,2 MW connection point, considering a cost of 25.000 €/km*

6.1.3. Sensitivity analysis for Briviesca, Spain

Table 6.4 shows for both cases, with and without sellback the result of the sensitivity analysis stated in the Chapter 6 introduction. The increase of the NPC is linear compared to the number of charging sessions per day, as it can be seen in Figure 6.9. However, the size of the solar PV plant not always, as it can be seen below.

On the one hand, in the case with possible sellback, the size of the solar PV plant does not increase linearly. This is because as already said in subsection 6.1.1. the most cost-effective system when combining a PV plant and a HPC station is a larger PV plant with an integrated HPC station. Thus, even if there are fewer cars charging the PV plant is still sized large due to the revenues from the grid sales. The little increase is due to the 'free' energy received when there are cars charging during sunlight, that of course rise according to the sessions per day.

On the other hand, in the case without possible sellback, the PV plant is sized according to the demand of the chargers and consequently grows linearly with the number of charging sessions per day.

Then, with Table 6.4 it can be stated that it is always better to integrate RE, even in the case without the possible sellback. Moreover, as there is the MOVES 3 incentive in this last case and the PV solar plant is not sized to sell energy, the initial investment for the most cost-effective system lowers to a 70 % compared to the case with possible sellback.

Table 6.4: Sensitivity analysis results considering a grid limit of 1,2 MW for Briviesca, Spain

Charging sessions/day		**38**	**77**	**154**
NPC only utility		1.162.107 €	1.937.795 €	3.507.415 €
Sellback possible	Contracted power	400/700 kW	400/700 kW	400/700 kW
	Solar PV	2300 kWp	2500 kWp	2900 kWp
	Wind	-	-	-
	BESS	-	-	-
	NPC	682.358 €	1.171.662 €	2.365.710 €
	NPC benefit compared to utility	479.749 €	766.133 €	1.141.705 €
	Initial capital	1.451.700 €	1.567.500 €	1.799.100 €
Sellback NOT possible MOVES 3 incentives considered	Contracted power	400/700 kW	400/700 kW	400/700 kW
	Solar PV	324 kWp	677 kWp	1328 kWp
	Wind	-	-	-
	BESS	-	-	-
	NPC	975.070 €	1.473.144 €	2.610.234 €
	NPC benefit compared to utility	187.038 €	464.651 €	897.181 €
	NPC difference with possible sellback	292.712 €	301.482 €	244.524 €
	Initial capital	232.412 €	355.219 €	581.391 €

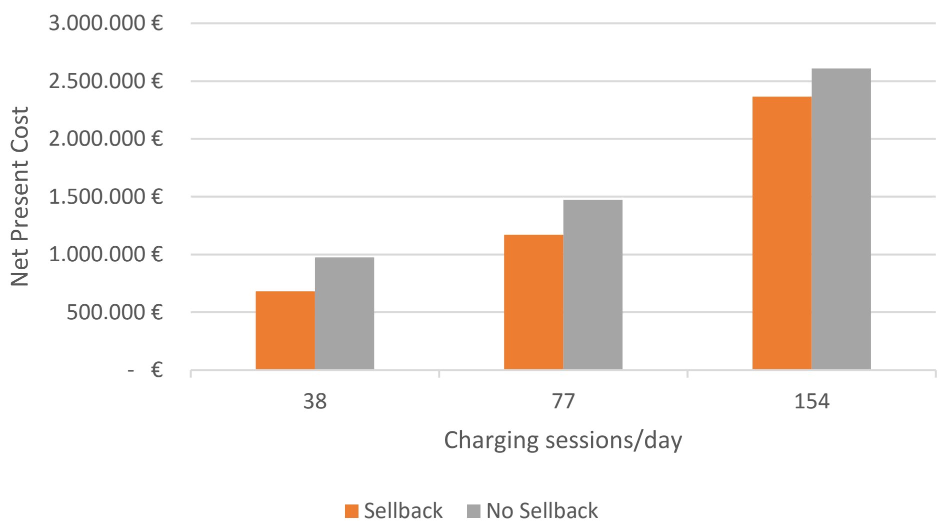

Figure 6.9: Variation of the NPC according to the charging sessions/day in Briviesca, Spain

6.1.4. Cost-effectiveness of battery storage in Briviesca, Spain

Battery storage is thought to be a good solution both to increase the power available and to store solar energy for later delivering it during the night. However, the simulations performed show that with the forecasted price of 495 €/kWh for 2025 is not cost-effective for Spain. If the costs lower to 120 €/kWh it could be cost-effective to integrate them to the system. In Figure 6.10 the usual use of a 340 kWh BESS in a system with a 1,2 MW grid limit is seen in green. It is nearly always charged during the first sunlight hours and discharged in the sunset so a couple of hours of grid purchases are saved. Even though, it is not considered a good option because 340 kWh serves 8 sessions of 40 kWh, being just a 10 % of all the daily sessions.

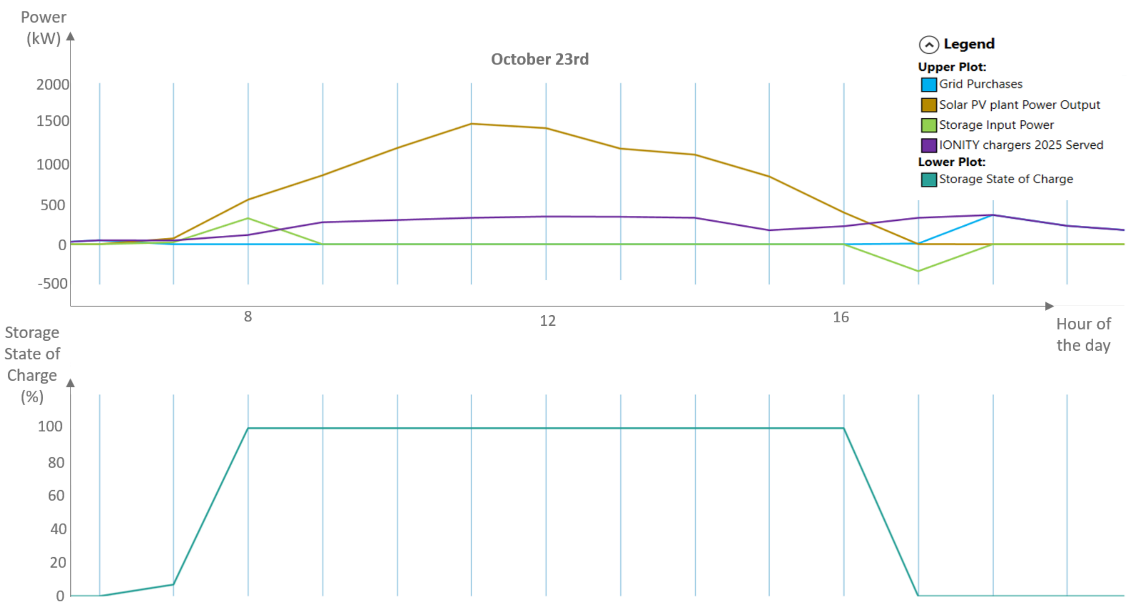

Figure 6.10: Usual use of a 340 kWh BESS for a 1,2 MW and 2500 kWp solar PV plant in Briviesca, Spain

6.2. Spekeröd station (Sweden)

Table 6.5 shows the electric supply systems that seem to be optimal depending on the grid limit. The most cost-effective system is with the biggest grid limit: 1,2 MW. In this case the cost of integrating a solar PV plant is very similar to having all the energy from the utility. Then, it can be observed that when the grid limit lowers, it is more cost-effective to build an MV line to the 1,2 MW connection point than installing the storage needed because the distribution MV lines have usually less than 20 km, therefore the results of the other cases do not make sense except if the place had a limited power and was isolated. However, in Sweden there does not seem to be this problem as the grid is solid and goes along the main roads where a station like this would be needed. In Figure 6.11 a graphical representation of the results can be observed.

Table 6.5: Electrical supply systems that seem to be optimal depending on the grid limit in Spekeröd, Sweden

Grid limit	1,2 MW	600 kW	240 kW	100 kW
Contracted power	600 kW	600 kW	240 kW	100 kW
Solar PV	281 kWp	350 kW	663 kW	228 kW
Wind		-	250 kW	6 MW
BESS	-	1,5 MWh	6,8 MWh	11 MWh
NPC	1.377.136 €	2.278.035 €	5.846.905 €	15.399.700 €
NPC only utility	1.387.389 €	Not possible	Not possible	Not possible
NPC benefit compared to utility	10.253 €	-	-	-
Min km of MV line* to be cost-effective		37	179	561

**MV line to the 1,2 MW connection point, considering a cost of 25.000 €/km*

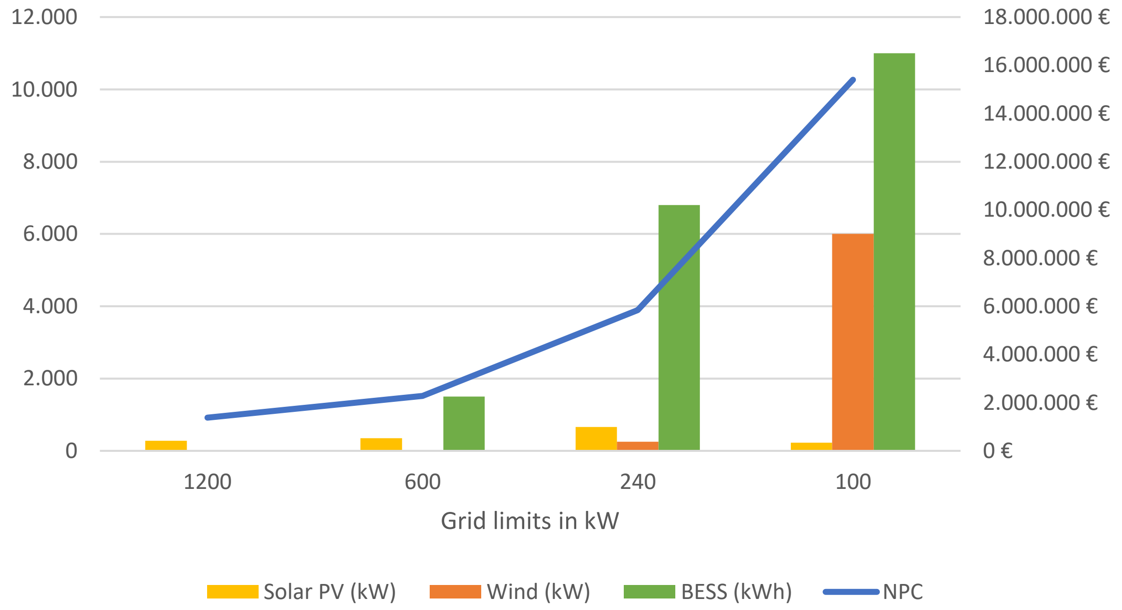

Figure 6.11: Electrical supply systems for the different grid limits in Spekeröd, Sweden

A detailed view of the most cost-effective system, the 1,2 MW grid limit with a 1250 kVA transformer installed, can be seen in the following paragraphs.

The solution that minimizes the Net Present Cost is a 1,2 MW MV connection with a 281 kW solar PV plant. This solution has a nearly equal cost than implementing a 100 kW wind turbine plus a 234 kW PV plant, with a 1,2 MW grid connection. However, the first option is detailed because it has a more feasible on-site implementation due to permitting procedures of wind turbines and distances required from households.

In Figure 6.12 the energy source of the chargers for this system can be observed. 81 % of the energy used will be purchased to the grid, whereas a 19 % will come from the on-site PV solar plant.

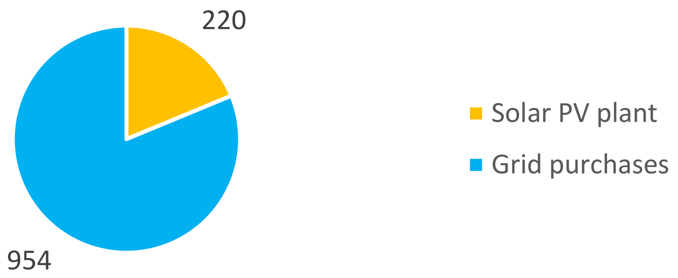

Figure 6.12: Energy source of the chargers for the 1,2 MW system in Spekeröd, Sweden

In Figure 6.13 the monthly electric production is shown. The irradiation curve is clearly seen and is very different from Spain. November, December, and January have a nearly zero PV production. In this case the grid purchases are considerably lower in the summer months, from March to September. However, as it can be seen in Figure 6.14 this decrease is not linear when it comes to the grid charges. This is because it depends on the hourly energy price of Nord Pool that was entered.

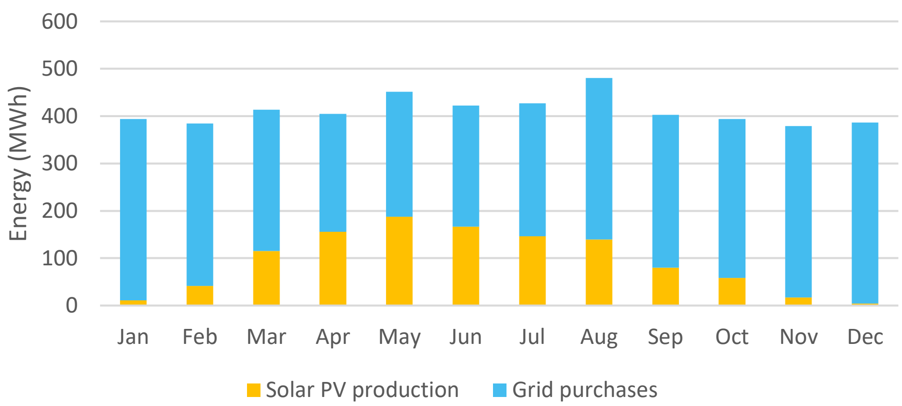

Figure 6.13: Monthly electric production for the 1,2 MW system in Spekeröd, Sweden

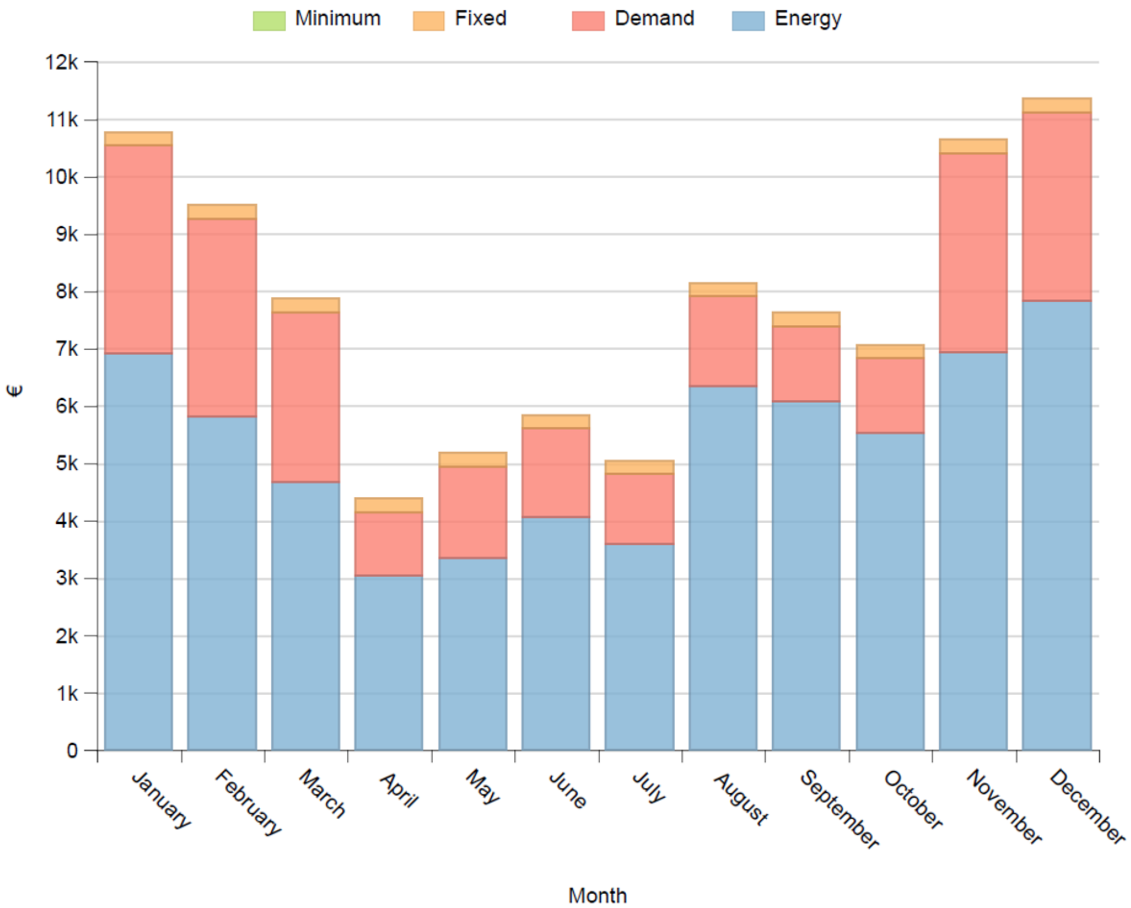

Figure 6.14: Monthly electrical bill breakdown for the 1,2 MW system in Spekeröd, Sweden

Figure 6.15 shows the difference between a cloudy and sunny day in spring. Whereas in the cloudy day the grid mainly meets the demand, in the sunny day there are some hours without grid purchases as the energy demanded by the chargers can be met by the solar PV plant.

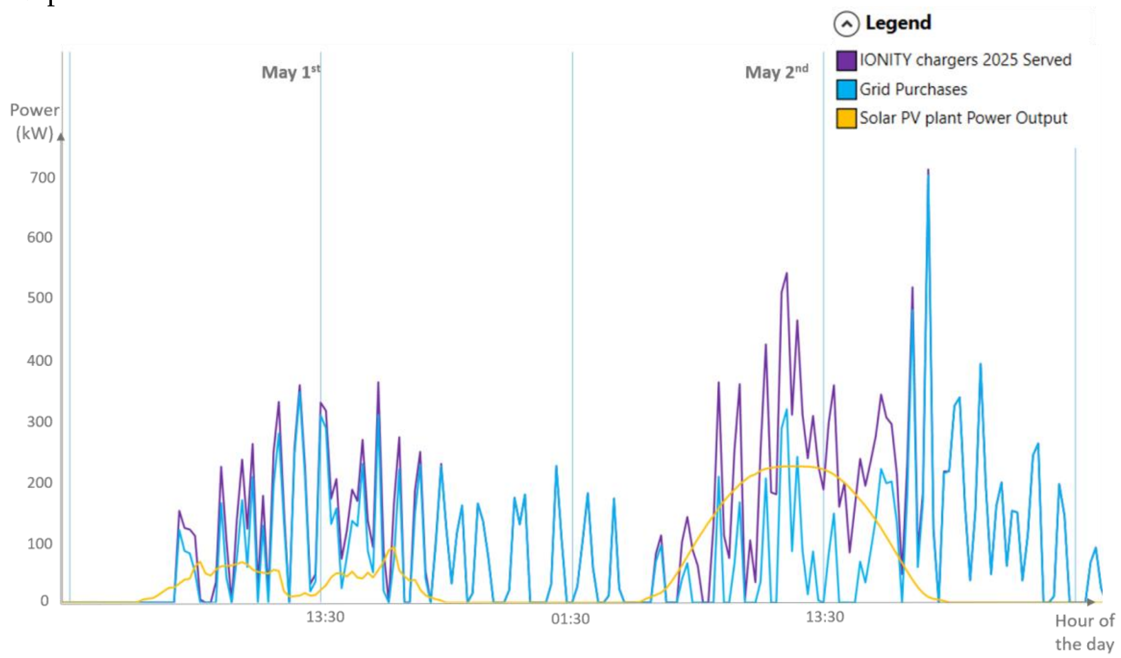

Figure 6.15: Hourly power graph of the different sources in a cloudy and sunny spring days for Spekeröd, Sweden

In Figure 6.16 the case of winter days without irradiance can be seen. All the demand is met by the grid, which is the reason why in the capture the purple curve is not seen, as it is behind the blue one of the grid purchases.

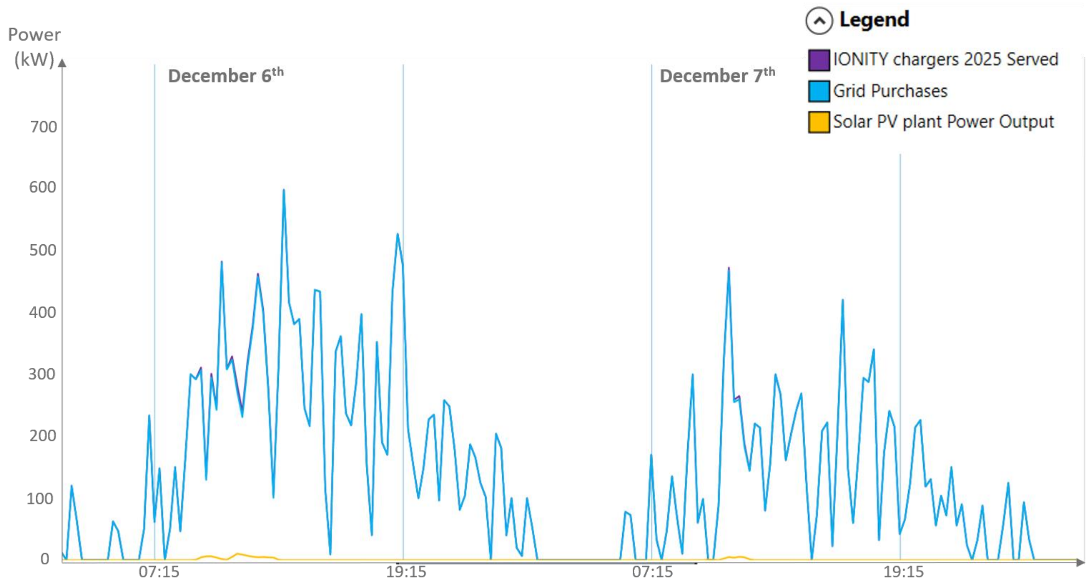

Figure 6.16: Hourly power graph of the different sources in winter days with nearly no irradiance for Spekeröd, Sweden

Figure 6.17 shows the hourly energy produced and consumed during a year. In yellow the solar PV production can be seen, which plays a main role from March to October; in blue the grid purchases can be observed, with a mainly constant shape and finally in purple the IONITY chargers forecasted demand is seen. Again, the reason why the IONITY consumption shown is much lower than the grid limit is the use of the average charging power for the simulations. If the maximum power was used then the graph would be much different.

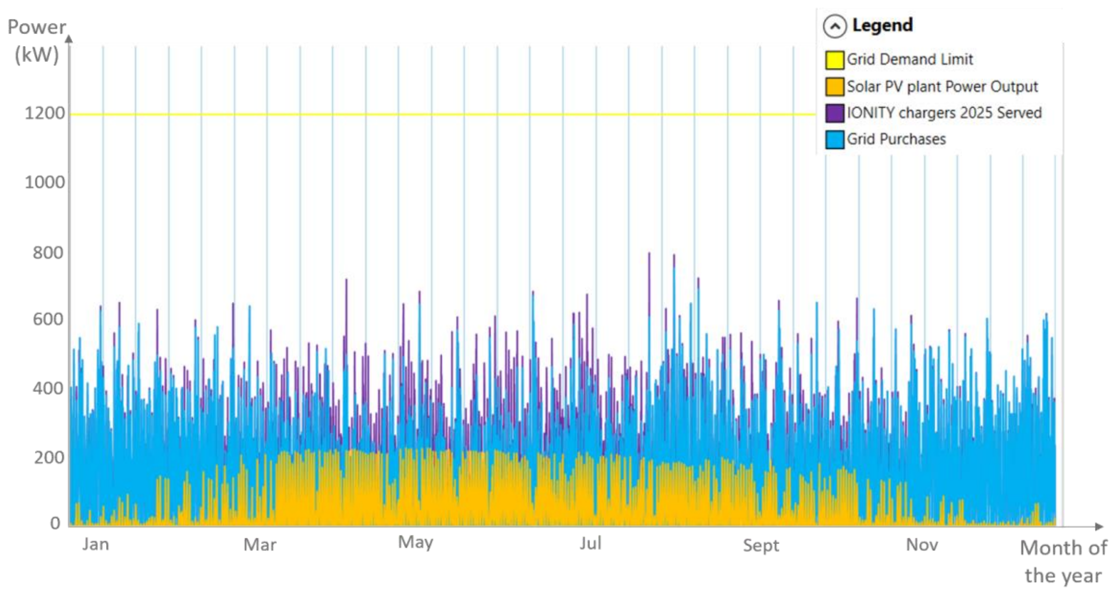

Figure 6.17: Hourly power graph of the different sources during the whole year for Spekeröd, Sweden

Regarding the economics, a summary can be seen in Table 6.6. It can be said that as the Internal Rate of Return (IRR) is greater than the interest rate (2 %) and the NPC is positive, the investment is profitable. The payback is acceptable being after the middle of the 20 years project lifetime. The Return on Investment (ROI) is low, but similar to the top power companies [30].

Table 6.6: Economic metrics for the 1,2 MW system in Spekeröd, Sweden

Metric	Value
Internal rate of return (IRR)	6,6 %
Payback	11,44 years
Return on investment (ROI)	4,5 %

6.2.1. Sensitivity analysis for Spekeröd, Sweden

The result of the sensitivity analysis stated in the Chapter 6 introduction can be seen in Table 6.7 for the station of Spekeröd, Sweden. In this case as it can be observed in Figure 6.18, the NPC grows linearly with the number of charging sessions per day, as it happened in the station in Spain. Contrastingly, the solar PV plant does not grow linearly. This is due to the nearly equal price it has compared to the utility.

Table 6.7: Sensitivity analysis results considering a grid limit of 1,2 MW for Spekeröd, Sweden

Charging sessions/day	38	77	154
Contracted power*	500 kW	600 kW	800 kW
Solar PV	43,8 kWp	281 kWp	335 kWp
Wind	-	***	***
BESS	-	-	-
NPC	772.492 €	1.377.136 €	2.434.184 €
NPC only utility	774.308,38 €	1.387.389 €	2.466.726 €
NPC benefit compared to utility	1.816 €	10.253 €	32.542 €

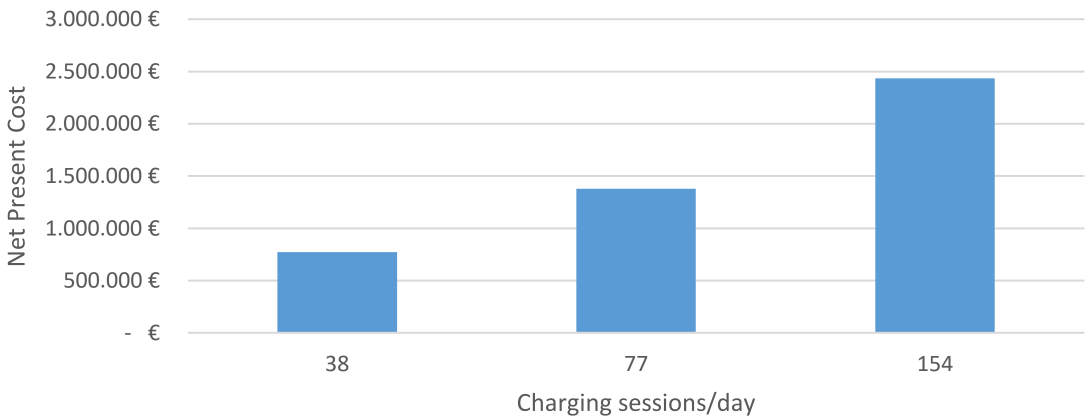

Figure 6.18: Variation of the NPC according to the charging sessions/day in Spekeröd, Sweden

6.2.2. Cost-effectiveness of battery storage in Spekeröd, Sweden

The battery storage does not seem to be a cost-effective component to include in the system. Even though if price drops to 100 €/kWh then it is economically viable to consider it. In Sweden as there is nearly no sunlight during winter months, the BESS is charged in low-rate hours and discharged in the high rate ones as it can be seen with a 340 kWh example in green for the 1,2 MW grid limit in Figure 6.19.

Figure 6.19: Usual use of a 340 kWh BESS during winter for Spekeröd, Sweden

7. SUGGESTED IMPLEMENTATION

For each location chosen, an implementation is proposed to see how it would fit in the reality and if there are space limits.

7.1. Briviesca (Spain)

There are two IONITY stations being built on each side of the AP-1 highway, in the State owned service areas. However, in this project the solar implementation is suggested for the northern station, where the MV connection point was given by the local DSO, Iberdrola Distribución Eléctrica. Northeast of the service area there is a green field of 22.160 m^2 which is suitable for installing the panels. Even though a building limit of 50 m from the exterior white line of the highway will need to be considered, so not all the surface is suitable for installing the panels. Then, on the other side of the corridor there is another green field of 16.185 m^2, therefore there is no problem with the space in this location.

As it has been shown in subsection 6.1.1, for a planned 1,2 MW grid connection with possible sellback, the best solution seems to be a 2500 kWp solar PV plant. The space this plant will occupy (A) can be determined from the output peak power (P)

$$A(m^2) = \frac{P(W)}{I\left(\frac{W}{m^2}\right)\cdot\eta} \tag{2}$$

where, I is the solar irradiance for a surface perpendicular to the Sun's rays (at sea level on a clear day is about 1000 W/m2, this value will be taken) and η is the conversion efficiency, an 18 % will be fixed for the calculations, the same value used for the simulations [22].

The result of this calculation is **13.888 m^2** needed for the solar PV panels installation. In the attached drawing in Appendix A it can be seen that an area of 16.767 m^2 is drawn to give space for the separation of the arrays. In Figure 7.1 part of the green field the solar PV plant would occupy can be seen.

Figure 7.1: Photo of part of the green field nearby the Briviesca Norte service area [Unai Baldús, February 2021]

Finally, a housing for the inverters and a new Low Voltage Distribution Board (LVDB) is suggested near the transformer station. The connection with the southern station will be done through the cabling planned to connect both of them as the power will only come from one side.

7.2. Spekeröd (Sweden)

The IONITY Spekeröd station is currently in operation. A canopy of 23,6 x 12 m is suggested to cover the whole charging area adding 1 m on each side except on the closest one to the service station where the little 'island' that is built will be covered too. That means that there is a surface of 283,2 m^2 that can be covered by PV panels. The height of the canopy will be of 4.5 m, the same of a gas station, so vans and trucks can also fit. However, considering the nearby flat green areas that are in the service station plot, there is an extra of 1876 m^2, making a total of 2159 m^2 that could be covered by solar panels.

As it has been shown in section 6.2, for the existing 1,2 MW grid connection, the solution for integrating renewable energy that seems to be the best is a 281 kWp solar PV plant. The space this plant will occupy can be calculated using equation (2).

The result of this calculation is **1561 m^2** needed for the solar PV panels installation. In Table 7.1 it can be seen that the panels area distributed into two parts: 283 m^2 on the canopy and 1278 m^2 on the green field. In the attached drawing in Appendix A it can be observed that an area of 1876 m^2 is drawn to give space for the separation of the arrays.

Table 7.1: Surface and output power of the two areas covered by solar PV panels

Area covered	Surface (m^2)	Output Power (kWp)
Charging station	283	50
Nearby green field	1278	231
Charging station + nearby green field	**1561**	**281**

Finally, a housing for the inverters and a new Low Voltage Distribution Board (LVDB) is proposed near the current transformer station. In the attached drawing all these elements can be seen.

In Figure 7.2 the field where the PV panels would be installed can be seen and in Figure 7.3 the charging area that will be covered by the canopy. If the canopy is installed the 3 lightning posts will need to be replaced by integrated lightning under the roof.

Figure 7.2: Green field next to the IONITY station where the PV panels could be installed [Albert Goday, May 2021]


Figure 7.3: Charging area that could be covered by a canopy with PV panels on it [Albert Goday, May 2021]

8. DISCUSSION

This chapter will analyse and discuss the results from the previous chapter and compare the cases of Spain and Sweden. It will also discuss how the results of the survey have been considered in the study and what is the users' opinion about it. In the following sections a discussion of the certainty of the results for both cases regarding common aspects such as the charging profile, the grid power limit and others, can be read.

8.1. Charging profile discussion

An important consideration for both cases is that the charging profile forecasted is for the period 2025-2045. The number of charging sessions per day is forecasted considering the available chargers and their occupation based on the EV market share of the mentioned horizon. On the other hand, the EV population is based on the available roll out plans for new EVs of the OEMs for the coming years. Then it is uncertain to predict how will the battery capacities be in 2035, if all the cars will have an 800 V architecture, allowing charging powers of >200 kW or if there will be a mix of technologies. Another important point which is more based in the number of charging stations needed and their location, is the mean range that EVs will have in 20 years. If the mean is >600 km, then HPC stations along highways will hardly never be used as it will be cheaper to charge at the destination of the trip. It could happen the case that these stations are mainly needed around cities to provide charging to people that will not be able to have the infrastructure at the parking place. For example, with the growth of shared, mainly electric, mobility options, also known as Mobility as a Service (MaaS), charging will be a crucial point. Then some Mobility Service Providers (MSPs) might choose the HPC stations as good way for their users to have the vehicles charged wherever it is possible, with a shorter time and without the need of planning a charging time or charging depots for their fleet.
To sum up, the above paragraph is to justify that the profile is based on the possible market of 2025 and that this can be very different from the one of 2040, which has not been predicted in this report. Moreover, it will depend on country to country as it already differs now and this has also been out of the scope as it has been considered the same profile for both cases.

8.2. Grid limit discussion

When having a lower grid limit, it is nearly always more cost-effective to build an MV line to the 1,2 MW capacity point because in the long-term the NPC will be lower. For this reason, it is very important to consider that even if in these years the use of charging points is low, this is due to the fact that the market is still in the early adopter phase. However, because of the willingness of governments and the stricter emissions regulations the probability of having the automotive market electrified in 2040 is very high. Considering this assumption, the infrastructure needs to be prepared for this horizon and it is therefore more cost-effective to plan a bigger grid connection than to have a smaller one. This is mainly the case when having the possibility of installing a solar PV plant. With a bigger grid connection, more revenues from selling energy to the grid will be allowed and then, even if a PV plant is not built, the electrical installation, the switching and transformer stations, will have to be upgraded at some point, costing more money and having less probability of getting the desired capacity in the connection point in the future.

8.3. Other general discussions

It must be said that the system has been studied as it was the same part that made the initial investment and then operated the station. However, this proposed system has a high initial capital and might not be in the core business of a CPO, which is not always an energy company. Thus, a good business case could be that a specialised enterprise installs and then operates the solar PV plant and then with a partnership with the CPO, this last receives solar energy in a much lower price than buying it from the grid.

Another limitation is that in both cases studied there are adjacent lands which make the implementation possible. If there were no adjacent lands it is important to consider the available space in the parking lot where the station is installed that will usually allow a minimum solar PV plant of 100 kWp. This will also be more cost-effective than not having it, as it will bring some revenues while lowering a bit the energy bill.

8.4. Spanish results discussion

The results show that for a charging profile of 77 sessions per day on average, forecasted for the period 2025-2045 the most cost-effective solution regarding the electrical supply is a 1,2 MW MV connection to the distribution grid together with a 2500 kWp solar PV plant.

Considering the real case that the demand will be growing, from the sensitivity analysis it is seen that the NPC varies linearly according to the charging sessions per day. This is a good result because as it has been said the advantage of the solar PV technology is that it is scalable. Hence, if the CPO makes the initial investment, it appears to be better to size the plant according to the demand of the chargers. However, if an independent company, whose core business is selling energy, does the initial investment, they should probably size it to the maximum available size to augment their revenues.

Then, if a company does not have a such big initial capital, the results suggest a good solution could be requesting the MOVES 3 plan, which has an important incentive for RE installations connected to the charging stations. A requirement of this grant plan is that no energy is sold to the grid [29], thus taking out of the equation third party companies whose business is to sell the energy back. In this case the solar PV plant, that the simulations indicate is the most cost-effective RE technology to integrate, will be sized according to the demand of the chargers and this increases linearly with the charging sessions per day.

Regarding the possibility of installing wind turbines, in the location studied in Spain it is not cost-effective and there is no reason why this component could be a good source of power for the chargers. The wind resource is much harder to predict than the solar one and does not have a ‘standard’ curve as the irradiation one. Moreover, wind speeds are lower for this site than in Sweden while the solar resource is higher, so the cost for wind energy cannot compete with solar PV. Then it is not correlated with the use of charging stations while the sunlight has a better approach to it. Finally, from a permitting perspective it is much more difficult to get the authorization and people living nearby could be against them.

8.5. Swedish results discussion

The simulations suggest that 3 solutions seem to have the similar lowest NPC. The first is a 1,2 MW MV grid connection with an integrated 281 kWp solar PV plant. The second is only supplying the chargers by the utility with the 1,2 MW connection and the third consists of integrating a 100 kW wind turbine in the mentioned grid connection. As it has already been discussed for Spain, this last solution is discarded due to the difficulty of predicting the resource and also because of the longer permitting procedure. Then, the main difference of integrating on-site RE or not, excluding the initial capital, which is higher, is the marketing advantage, that will bring more customers to the station than to a competitor one, as it has been seen in the survey results. The parity of the Net Present Cost between a system with or without solar PV panels can be explained with Figure 6.14, which shows the monthly electric bill breakdown, with a much lower cost between April and July. These savings during the 20 years period seem to be equal to the initial capital and O&M for the solar PV panels.

Considering the real case that the demand will be growing, the sensitivity analysis indicates that the NPC varies linearly according to the charging sessions per day. As discussed for the Spanish case, this is an advantage due to the scalability of solar PV technology. A difference from the Spanish results is that as in Sweden the revenues from selling energy to the grid are low, for the moment there does not seem to be a big market interested in investing in utility scale solar PV plants. Hence, from a business perspective, in Sweden it makes more sense that the initial investment is made by the CPO and that this part receives the 'free energy' from the sun afterwards.

8.6. Comparison of the Swedish and Spanish results

The results of both cases are very different mainly because of the variation on the irradiance from southern to northern Europe. The results indicate that in Spain the most cost-effective way of profiting of solar energy for a HPC station is to build a 2500 kWp plant. The reason for building such a large installation is not only the revenues given by the sale of energy but the possibility of having the peak power covered during all hours of daylight. With this, no storage is needed, which as it has been seen it is a more expensive solution according to the forecasted Li-Ion BESS prices per kWh. In the analysis of no possible sellback, the results suggest that a PV plant of 677 kWp is the most cost-effective option, strengthening the argument that the installation of the PV plant seems to be the best option to reduce the total cost of the electrical supply. In Sweden, where sellback could be considered as irrelevant because of the low revenue, the optimized PV plant is of 281 kWp, due to lower irradiance.

In Figure 8.1 a general comparison for both countries with the same 1,2 MW grid limit regarding the NPC and the economic rates can be seen. The case of Spain is with possible sellback of energy.

An interesting economical comparison is not only seen with the NPC but also with the Levelized Cost of Energy (LCOE). This value is calculated as follows in Equation (3). It divides the annualized cost of producing electricity by the total electric load served.

$$LCOE = \frac{C_{ann,tot}}{E_{served}} \tag{3}$$

In Figure 8.2 the different costs can be seen with the option that might be the most cost-effective compared to the supply of the grid in both cases.

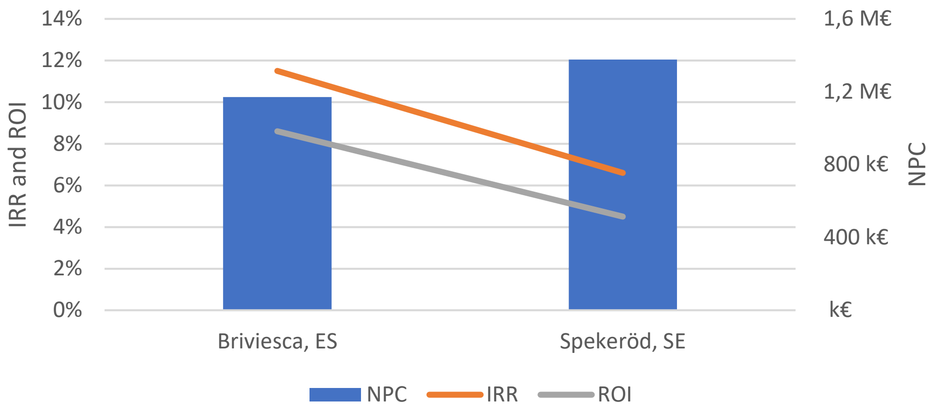

Figure 8.1: Economic comparison of the systems proposed for the Spanish and Swedish stations.

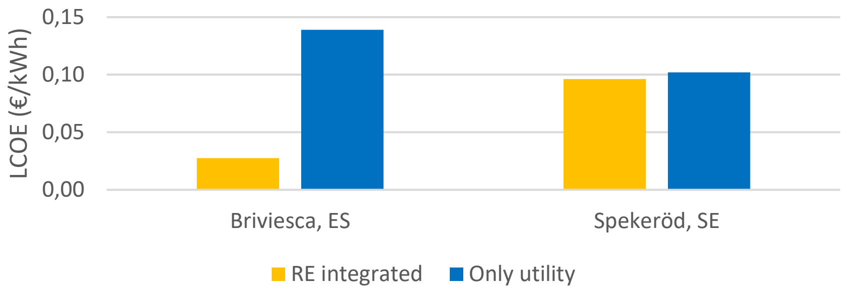

Figure 8.2: Comparison of the LCOE in both stations depending on the integration of renewable energy or not.

8.7. Survey results discussion

The questions regarding the use of fast (50 kW) and HPC (>50 kW) stations suggest that 65 % and 53 % of users only make use of them during long-distance travels. These results support the hypothesis, which this Thesis does not study but is based on, that HPC stations should be located along the major corridors. Then, as it has been stated in section 5.2 of the EV charger model, the results of the hour when people charge are similar, except the peak at midday, to the Fastned published profile, making the results of the survey trustworthy. The mean of the SoC of arrival of the users who have used a HPC station is utilized for the mean charging time. While EVDataBase gives the duration for a charge from 10 to 80 %, as the mean of the survey is 23 % SoC, a charging session from the 25 % to the 80 % is considered. This is a crucial aspect that could change in the horizon studied due to the progressive disappearance of the range anxiety concept. The average fast charging power results of the survey are not considered for the modelling as it is constantly increasing and the EV population in the period studied will differ considerably from the current one.

It is interesting to see how the use of renewable energy is the 4th aspect more preferred for users when searching for a HPC station, before the services available or the canopy covering the chargers. Regarding this aspect, 70 % of the drivers polled say the canopy would positively impact their decision on where to fast charge. Finally, a 91 % of the drivers consulted affirm that they would prefer charging in a RE powered HPC station if they had the opportunity to do it. Therefore, these results validate the viability of this study not only in the technical part but also in the social one, crucial to achieve the forecasted demand.

9. CONCLUSIONS

The purpose of the current study was to determine the cost-effectiveness of integrating renewable energy and battery energy storage in a High Power Charging (HPC) station for Electric Vehicles (EVs). Two IONITY stations in Spain and Sweden have been studied and compared. A survey was conducted to more than 290 EV users of Europe to see their opinion regarding the use of renewable energy for HPC stations. To do the analysis, the wind and solar resources of each location were entered as well as the forecasted demand for charging of 77 sessions per day on average. The costs of each component have been estimated for 2025 and the detailed grid tariffs of both countries have been set. Then, using HOMER Energy software, the systems with the lowest Net Present Cost (NPC) were determined for different grid limits. Finally, a sensitivity analysis was made for different charging sessions per day.

This study has shown that for both cases, a grid connection of 1,2 MW is the most suitable grid limit for the forecasted demand. In Briviesca, Spain integrating a 2500 kWp solar Photovoltaic (PV) plant is the most cost-effective solution if the sale of energy to the grid is possible; if not, a 677 kWp solar PV plant seems to be the best option. For southern Sweden, the cost of integrating a 281 kWp solar PV plant makes no significant difference to installing a wind turbine or to feed the chargers only with the utility. Nevertheless, solar PV technology is chosen due to environmental and marketing purposes.
In Spain solar PV without HPC is cost effective, but by combining them a lot is saved by letting them share grid connection. In Sweden, the solar PV is probably not profitable on its own, but when sharing the grid connection with the HPC it becomes cost neutral.

The second major finding was that storage is not cost-effective as long as the grid limit is sufficient to absorb the demand. If not, building a Medium Voltage (MV) line to the bigger capacity connection point is a much more cost-effective alternative. Exceptions are the stations built in markets where the share of EVs is low. Then, it makes sense not to have a big grid connection but to increase it with storage due to the low number of charging sessions per day. However, as the market is growing fast there is the risk of not recovering the investment in the battery because a bigger grid connection will need to be built anyway.

Multiple sensitivity analysis depending on the number of charging sessions per day revealed that the NPC increases rather linearly with the demand to be met, which suggests that there is no clear threshold in the costs, and it will be almost as cost effective to build a smaller charging station as a bigger one. As the proposed technology, solar PV, is also scalable, it perfectly fits this growing market. Thus, it is possible to build smaller charging stations with solar PV integrated that grow with the market. However, the grid connection should be oversized to be prepared for the future increase of demand.

The survey launched to EV users has shown that more than 90 % of them would prefer charging in a renewable energy powered HPC station if they had the opportunity to do it. This finding is crucial to justify the viability of the installation and strongly supports the technical and economical results.

This study should help to improve predictions on how to build the charging station of the future, where with a mature market, the energy bought to the grid will be the main operational cost of the CPO and it can be lowered by integrating a solar PV plant.

9.1. Limitations

The major limitation of this study is the uncertainty of the EV charging characteristics of the 2030 market. An EV population, considering the known plans of the OEMs, with their charging powers and durations was considered but a lot can change in the following years. Using the component prices projected for 2025 by IRENA, is another limitation, as they are forecasted to drop in the following 20 years. Thus, if part of the investment was done in 2035, the installation costs for all the components, especially Li-Ion batteries, would be much lower, changing the NPC and subsequently the most cost-effective system.

9.2. Implications for future practice

The insights gained from this study may be of assistance to CPOs and energy companies that have plans for future roll out of HPC and renewable energy plants respectively, both in rapidly growing markets. For all planned HPC stations, particularly in Spain, a feasibility study of installing PV should be done either by the CPO or an external company. Even if in the coming years the difference of supplying the chargers from the grid or from the PV plant could be negligible, once the market will be mature and a significant number of charging sessions per day will be achieved, the difference will be immense. In the meantime, important revenues from selling energy to the grid can be made from the plant and both installations can share the same MV connection, which is an important part of the initial investment. If CPOs and energy companies reach an agreement or even if a CPO considers that it could be part of their business, optimal systems will be seen. In the case of southern Sweden, solar PV panels can be installed on the canopy of the same charging station and of nearby buildings. Even though, a utility scale plant of more than 500 kWp does not seem to be profitable in the medium-term.

9.3. Future work

A natural progression of this work is to detail the implementation and to analyse if for a new station it is more cost-effective to install chargers without the AC-DC conversion, so the PV panels can be directly connected to a DC bus and then only a DC-DC converter would be needed in each charger. These chargers are already available at the market, only the integration with solar PV needs to be studied.

In this project it has only been investigated if battery energy storage is cost-effective for the electrical supply of the chargers, but it has not been considered if this battery can simultaneously serve other purposes, like for example peak shaving for the grid, and therefore become cost-effective. If the debate is to be moved forward, alternative to Li-Ion storage need to be investigated as large storage with lower CAPEX could be key to reduce even more the grid costs during nights and peak hours, especially in Sweden.

Finally, further work needs to be done to establish whether this solution is also cost-effective for other European locations, in accordance with the growing networks that operate in all the continent.

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battery:prev~next=10~200|range-slider-eff:prev~next=100~300|range-slider-fastcharge:prev~next=0~1500|paging:currentPage=0|paging:number=9 (accessed Apr. 23, 2021).

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APPENDIXES

APPENDIX A: DRAWINGS OF THE PROPOSED IMPLEMENTATIONS FOR BRIVIESCA, SPAIN AND SPEKERÖD, SWEDEN

APPENDIX B: HOMER GRID REPORTS OF THE MORE COST-EFFECTIVE SYSTEMS FOR BOTH CASES

LOCATION

Autopista del Norte, AP-1, km 36
09240 Briviesca, Burgos (Spain)

DENOMINATION

PLANNED IMPLEMENTATION FOR A 2500 kWp SOLAR PV PLANT

DOCUMENT

PROPOSED SIZING FOR A SOLAR PV PLANT ON THE GREEN FIELD NORTH OF THE SERVICE AREA.
THIS PLANT WILL BE INTEGRATED TO THE ELECTRICAL SUPPLY OF THE IONITY HPC STATION ADDING INVERTERS AND A NEW LVDB.

NOT SCALABLE

DATE
May 2021

AUTHOR
Albert Goday Sagarra

CHALMERS University of Technology

LOCATION

Rastplats Spekeröd 302

444 93 Spekeröd (Sweden)

DENOMINATION

PLANNED IMPLEMENTATION FOR A 281 kWp SOLAR PV PLANT

DOCUMENT

PROPOSED SIZING FOR A CANOPY COVERING THE CHARGING AREA WITH SOLAR PV PANELS ON IT AND A SOLAR PV PLANT ON THE FLAT FIELD.
THIS PLANT WILL BE INTEGRATED TO THE ELECTRICAL SUPPLY OF THE IONITY HPC STATION ADDING INVERTERS AND A NEW LVDB.

NOT SCALABLE

DATE

May 2021

AUTHOR

Albert Goday Sagarra

CHALMERS UNIVERSITY OF TECHNOLOGY

CHALMERS University of Technology

CREADO CON UNA VERSION PARA ESTUDIANTES DE AUTODESK
CREADO CON UNA VERSIÓN PARA ESTUDIANTES DE AUTODESK
CREADO CON UNA VERSION PARA ESTUDIANTES DE AUTODESK

HOMER Grid Report

Table of Contents

Site Information

Location	AP-1, 09240 Briviesca, Burgos, Spain
Latitude	42 degrees 31,78 minutes N
Longitude	3 degrees 19,87 minutes W
Time zone	Europe/Madrid

Average Electric Energy Consumption:

Daily	Monthly	Annual
10.100,5 kWh/day	307,2 MWh/month	3.686,7 MWh

Annual Peak Electric Demand:

16 de julio / 656,33 kW

Figure 1: Load Profile for the Day on Which the Largest Demand Occurs (16 de julio)

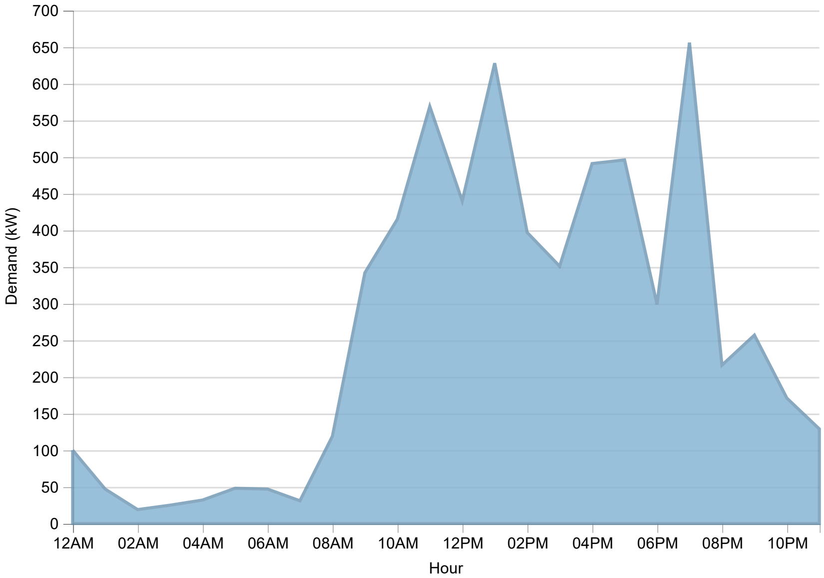
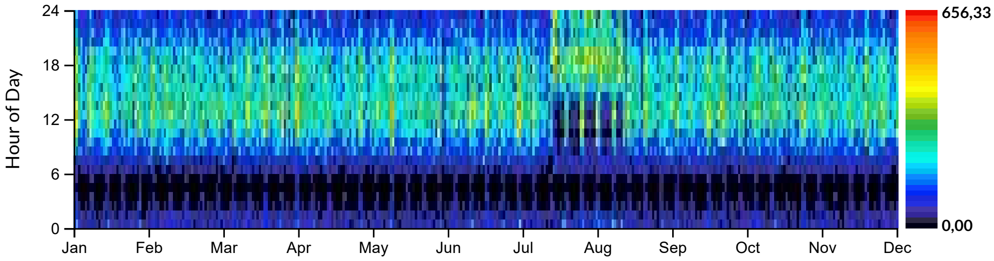


Figure 2: Heat Map, showing Energy Consumption Patterns

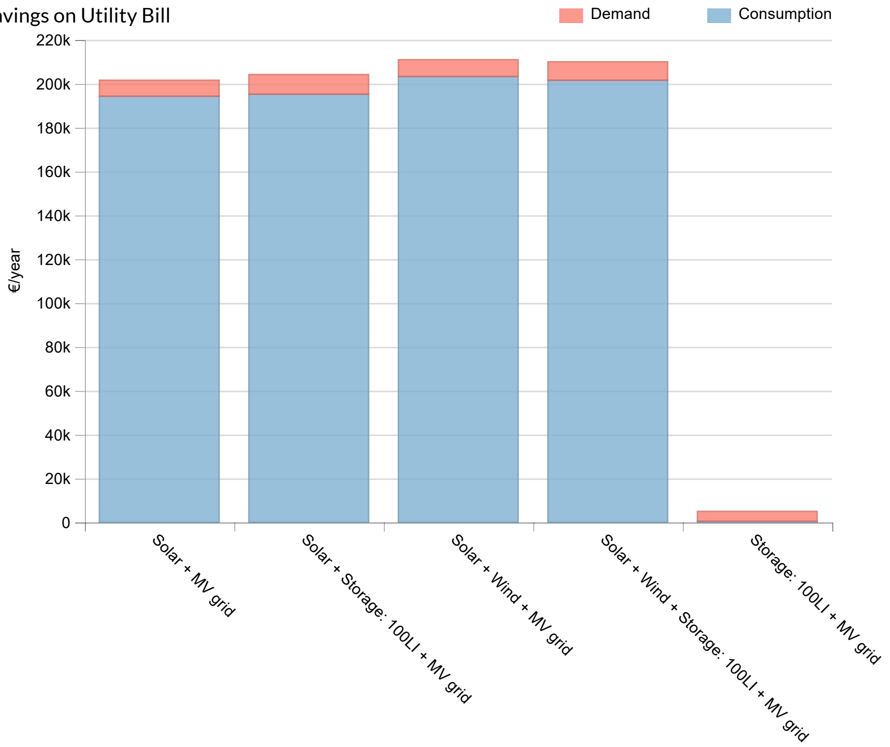


Overview of Optimized System Installation Options

This section presents a summary and comparison of some possible systems. The following sections give details on each system.

The lowest net present cost system architecture is:	Solar + MV grid
Your annual savings can be:	201.530 €
System capital cost:	1.567.500 €
Over the project lifetime of 20 years, your savings can be:	4.030.591 €
Your IRR can be:	12%
Your payback time can be:	7,8 years

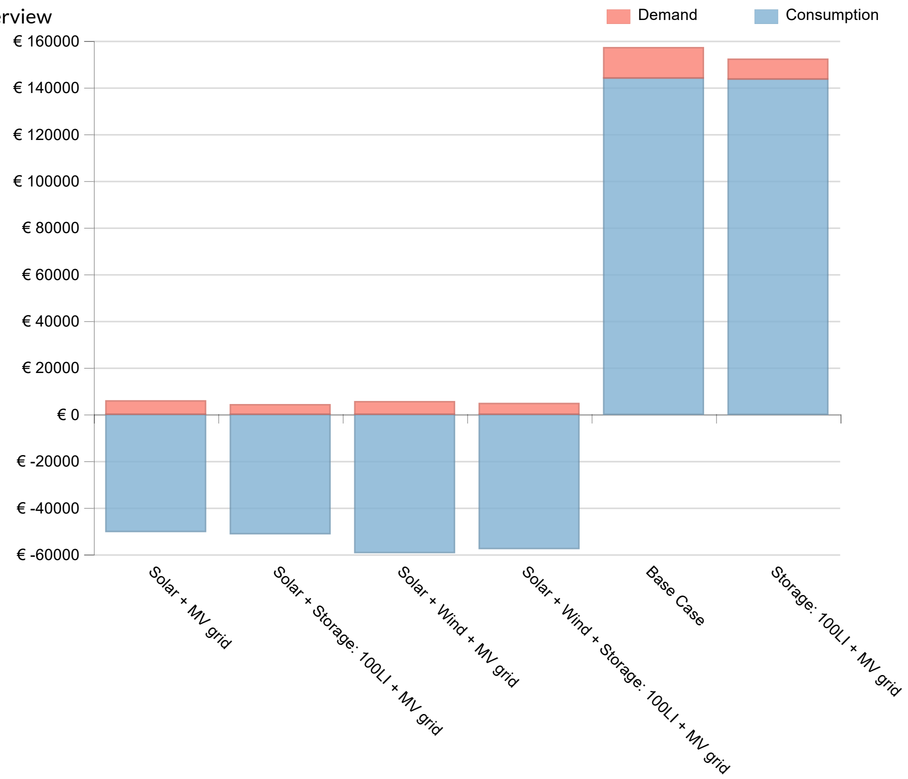
Figure 1: Projected Annual Savings on Utility Bill



	Base Case	Solar + MV grid	Solar + Storage: 100LI + MV grid	Solar + Wind + MV grid	Solar + Wind + Storage: 100LI + MV grid	Storage: 100LI + MV grid
Costs and Savings						
CAPEX	120.000 €	1.567.500 €	1.623.341 €	1.815.500 €	2.061.205 €	189.194 €
OPEX	156.973 €	-€34.182	-€34.000	-€37.348	-€27.077	154.053 €
Annual Total Savings (€)	0 €	191.156 €	190.973 €	194.322 €	184.050 €	2.920 €

	Base Case	Solar + MV grid	Solar + Storage: 100LI + MV grid	Solar + Wind + MV grid	Solar + Wind + Storage: 100LI + MV grid	Storage: 100LI + MV grid
Annual Utility Bill Savings (€)	0 €	201.530 €	204.130 €	210.896 €	209.942 €	4.936 €
Annual Demand Charges (€/yr)	12.953 €/yr	5.674 €/yr	4.022 €/yr	5.326 €/yr	4.561 €/yr	8.458 €/yr
Annual Energy Charges (€/yr)	144.020 €/yr	-€50.230/yr	-€51.178/yr	-€59.248/yr	-€57.530/yr	143.579 €/yr
Economic Metrics						
Discounted payback time (yrs)		10,8	11,5	13,2	18,2	
Simple payback time (yrs)		7,8	8,1	9,0	10,9	
LCOE (€/kWh)	0,139 €/kWh	0,027 €/kWh	0,029 €/kWh	0,031 €/kWh	0,041 €/kWh	0,142 €/kWh
IRR %		11,54%	10,98%	9,49%	7,01%	
Net Present Cost (€)	1.937.795 €	1.171.662 €	1.229.612 €	1.382.996 €	1.747.648 €	1.973.174 €
Environmental Impact						
CO_2 Emissions* (metric ton/yr)	759,8 t/yr	271,5 t/yr	254,9 t/yr	248,1 t/yr	221,4 t/yr	761,9 t/yr
Annual Fuel Consumption (L/yr)	n/a	n/a	n/a	n/a	n/a	n/a

Figure 2: Utility Bill Overview



Demand Charge Reduction and Calculation Introduction

HOMER Grid is a tool that can help a developer or site owner outline different options for reducing a site's electricity bill. It compares the costs and savings for installing different combinations of batteries, solar panels, and generators. HOMER Grid uses a powerful optimization to find the system that will maximize your savings.

A bill from an electric utility can be comprised of a few different types of charges. The energy charge is for the quantity of energy in kilowatt-hours (kWh) you used in total for the month. The demand charge is for the highest peak power draw in kilowatts (kW) or megawatts (MW) for the month. Finally, the fixed charge is a charge that is the same every month and is not affected by your consumption or peak demand.

HOMER Grid integrates with Genability's utility rate database, ensuring the most accurate and up-to- date results possible. HOMER Grid is the only demand charge reduction and optimization tool that considers generators as a method for peak shaving, following in HOMER's technology agnostic tradition.

The Grid tool provides an estimate. You can help ensure the accuracy of your results by checking that the baseline electricity costs listed in the report (energy and demand charges) match your actual electricity bills.

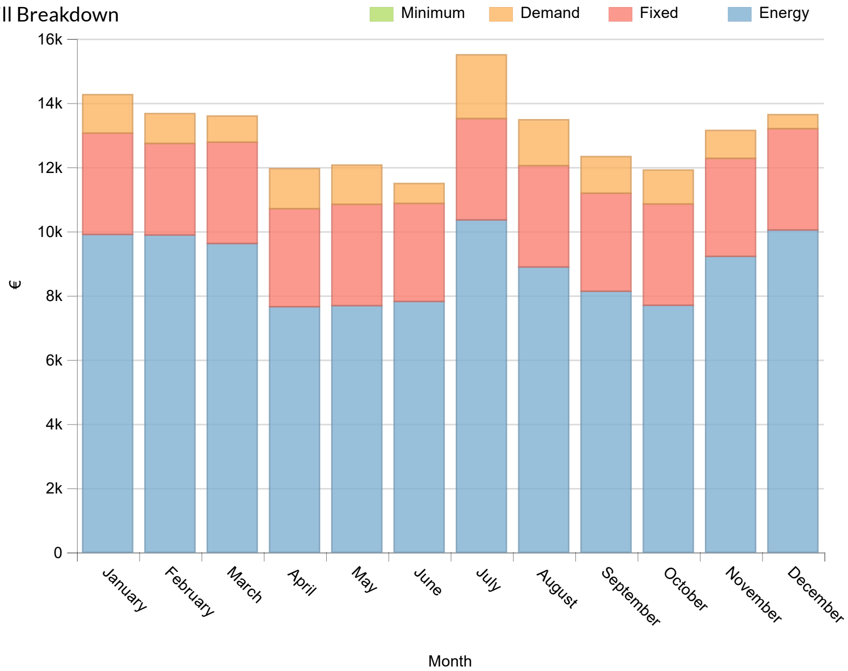
Your feedback is valuable to us. Please contact HOMER Energy with your feedback about what you'd like to see in this report and what feature requests you may have.

Base System Electric Bill

Tariff: 6.1TD_400kW NT

	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	9.899 €	9.882 €	9.617 €	7.647 €	7.681 €	7.812 €	10.353 €	8.885 €	8.129 €	7.693 €	9.216 €	10.038 €
	102.158 kWh	93.929 kWh	101.854 kWh	101.344 kWh	102.032 kWh	93.118 kWh	103.169 kWh	108.638 kWh	97.379 kWh	102.896 kWh	96.868 kWh	98.866 kWh
	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh
Demand Charges and Peak Demand	1.199 €	930 €	814 €	1.248 €	1.223 €	619 €	1.987 €	1.429 €	1.141 €	1.057 €	869 €	437 €
	555 kW	533 kW	505 kW	566 kW	558 kW	483 kW	656 kW	584 kW	552 kW	536 kW	516 kW	456 kW
Fixed charges (€)	3.157 €	2.851 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €
Monthly Total	14.255 €	13.664 €	13.588 €	11.950 €	12.060 €	11.486 €	15.496 €	13.471 €	12.326 €	11.907 €	13.140 €	13.632 €
Annual Total	156.973 €											

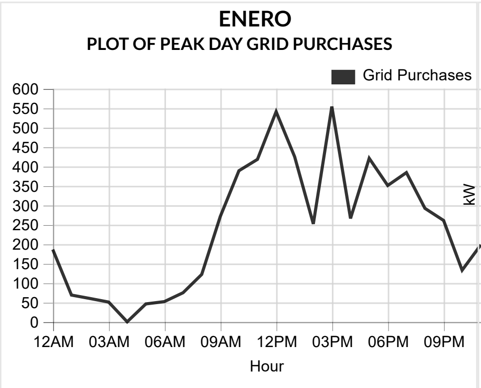
Figure 1: Monthly Electrical Bill Breakdown

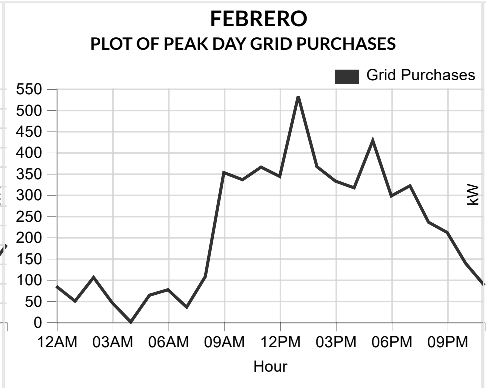


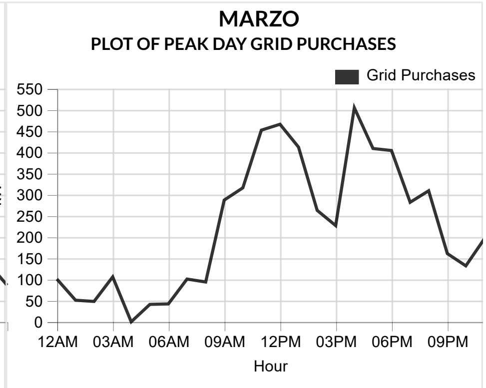
Carbon Dioxide Emissions

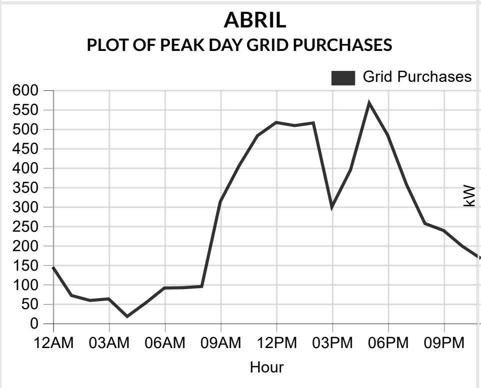
	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	65 t	59 t	64 t	64 t	64 t	59 t	65 t	69 t	62 t	65 t	61 t	62 t
Annual Total (metric tons)	760 t/yr											

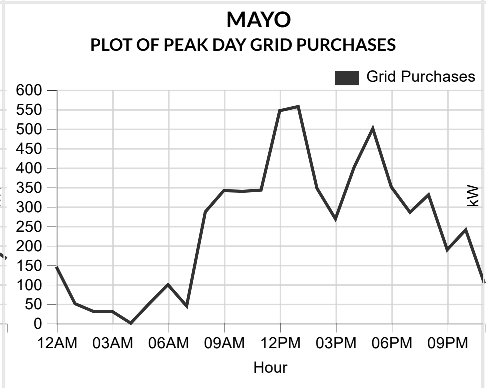
* emissions are based on an assumption of your grid's generation sources.

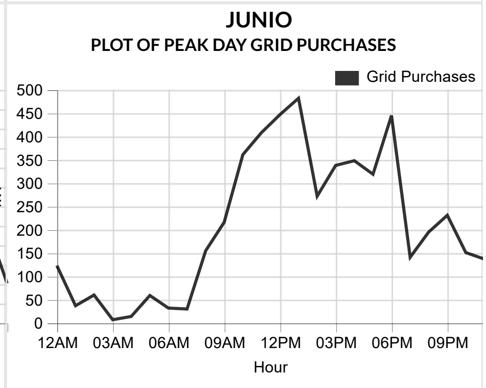


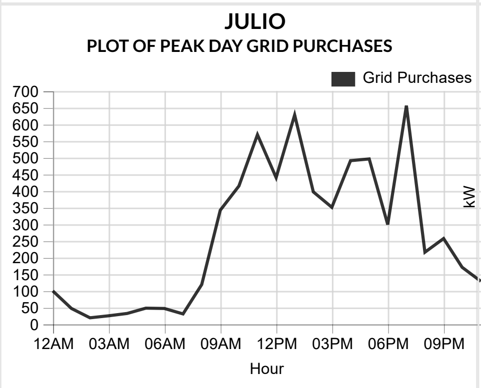


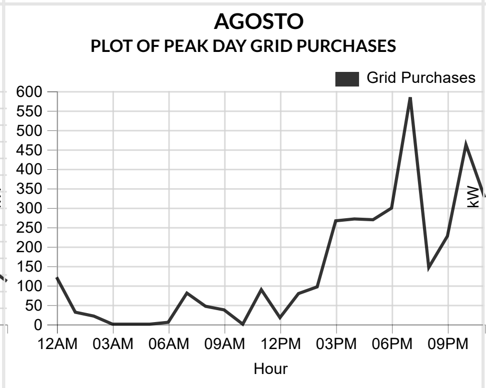


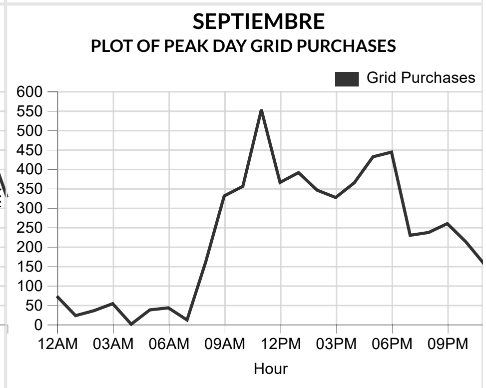






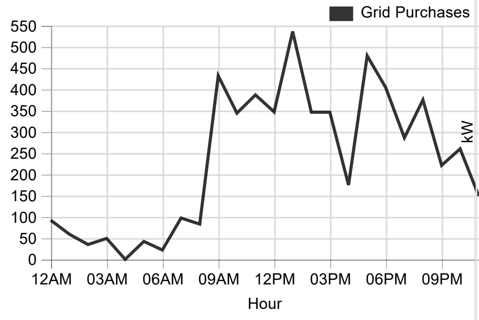






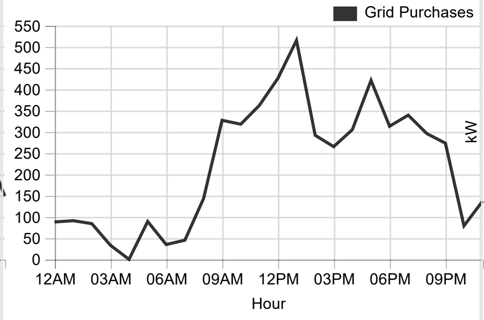
OCTUBRE

PLOT OF PEAK DAY GRID PURCHASES



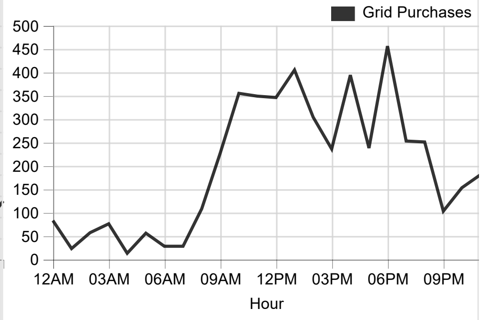
NOVIEMBRE

PLOT OF PEAK DAY GRID PURCHASES



DICIEMBRE

PLOT OF PEAK DAY GRID PURCHASES



System Details

System #1: Solar + MV grid

Savings Overview: Between System #1 (Solar + MV grid) and Base Case

Average annual energy bill savings:	201.529,53 €
CAPEX	1.567.500,00 €
Payback time (simple/discounted):	7,8/10,8 years
Internal Rate of Return (IRR)	11,54%
Project lifetime savings over 20 years:	4.030.591 €

Installation Recommendation: System #1

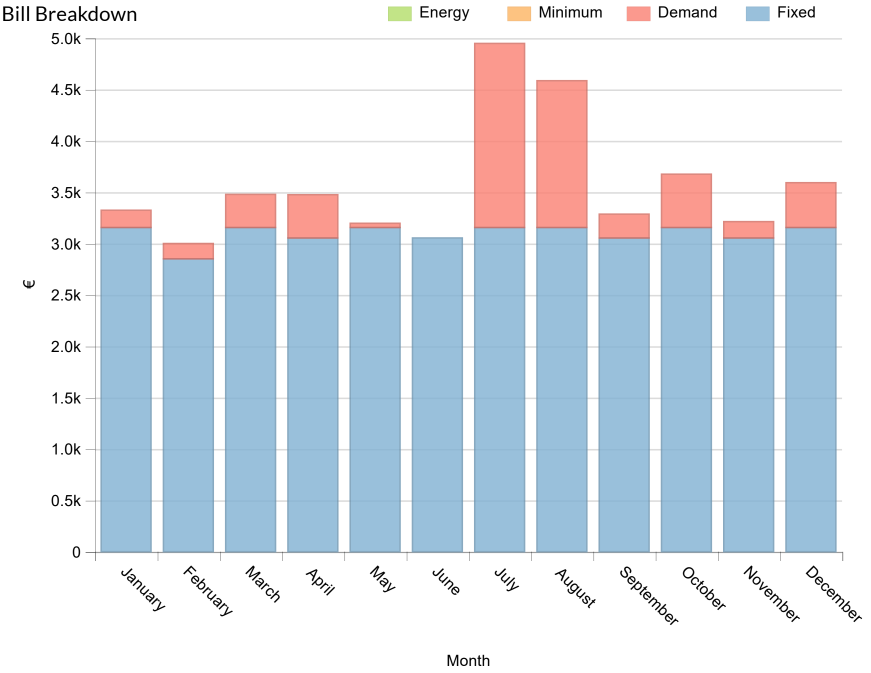
Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Solar PV plant	0,58 €/watt	2,5E+03 kW	1.447.500 €	16.750 €/yr

Electrical Bill (Predicted): System #1

Tariff: 6.1TD_400kW NT

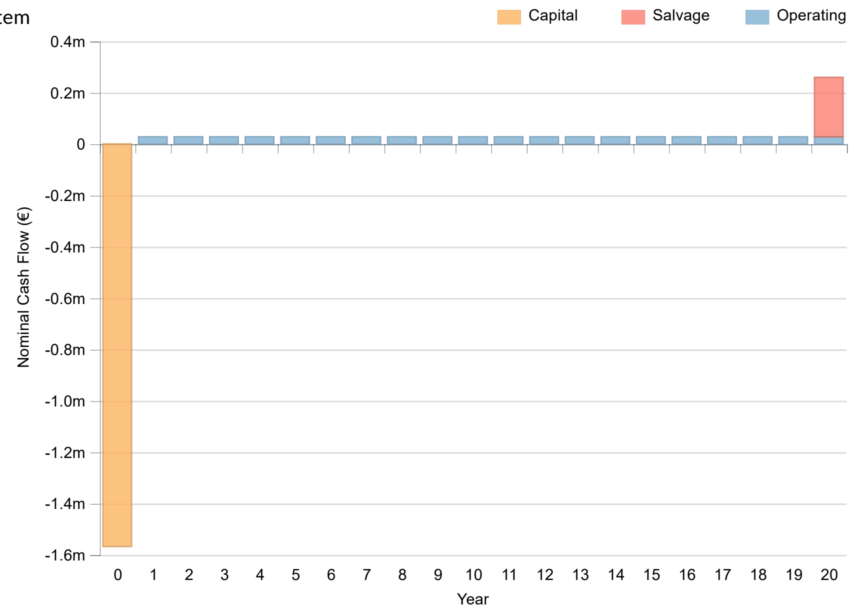
	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	-€1.008	-€2.572	-€7.903	-€9.270	-€10.899	-€12.110	-€12.974	-€9.993	-€9.846	-€6.979	-€2.012	-€1.830
	43.809 kWh	35.865 kWh	32.731 kWh	30.395 kWh	27.855 kWh	22.536 kWh	26.362 kWh	53.878 kWh	31.254 kWh	39.939 kWh	40.582 kWh	44.438 kWh
	108.502 kWh	121.309 kWh	213.936 kWh	231.323 kWh	261.116 kWh	273.074 kWh	301.361 kWh	292.924 kWh	243.066 kWh	200.859 kWh	111.968 kWh	124.987 kWh
Demand Charges and Peak Demand	169 €	149 €	322 €	421 €	42 €	0 €	1.793 €	1.429 €	233 €	520 €	159 €	437 €
	422 kW	421 kW	442 kW	456 kW	405 kW	289 kW	631 kW	584 kW	431 kW	467 kW	421 kW	456 kW
Fixed charges (€)	3.157 €	2.851 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €
Monthly Total	2.318 €	428 €	-€4.424	-€5.794	-€7.701	-€9.055	-€8.024	-€5.408	-€6.559	-€3.303	1.202 €	1.763 €
Annual Total	-€44.556											

Figure 1: Monthly Electrical Bill Breakdown



Cash Flow Summary: System #1

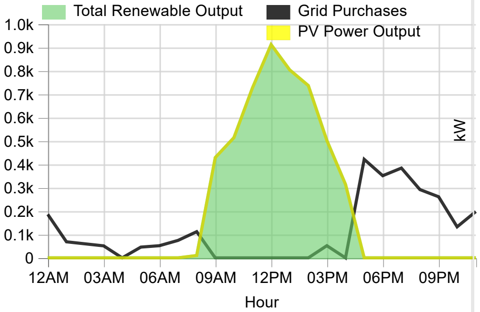
Figure 2: Cash Flow for System



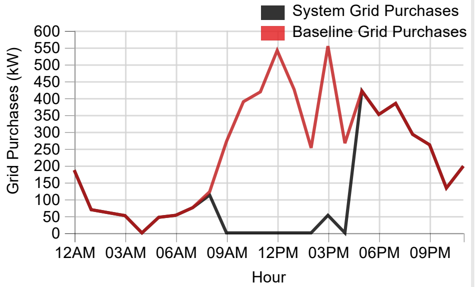
Performance Summary: System #1

ENERO

PLOT OF PEAK DAY PV, AND GRID PURCHASES

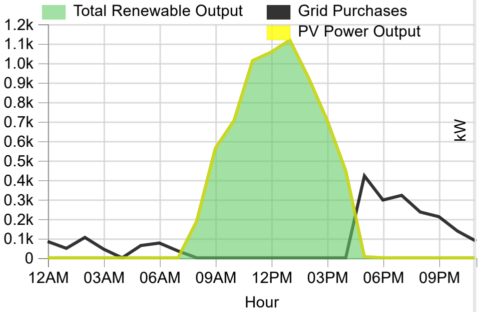


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

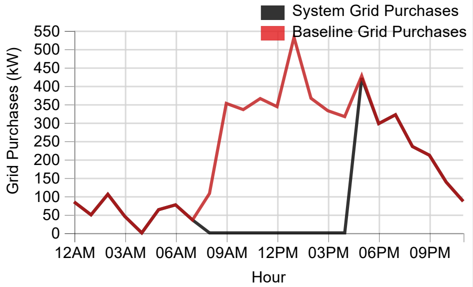


FEBRERO

PLOT OF PEAK DAY PV, AND GRID PURCHASES

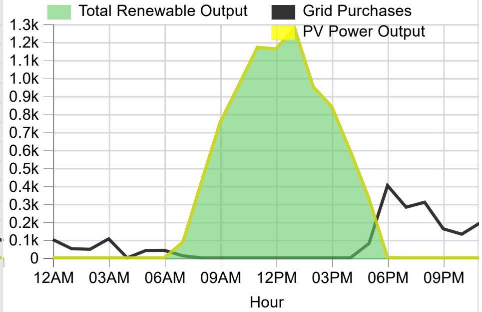


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

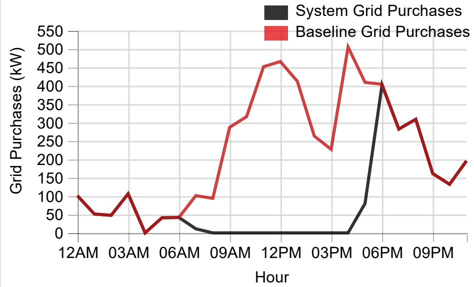


MARZO

PLOT OF PEAK DAY PV, AND GRID PURCHASES

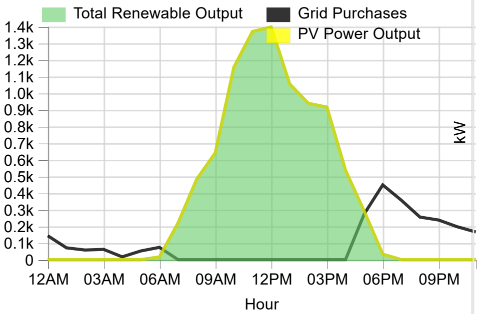


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

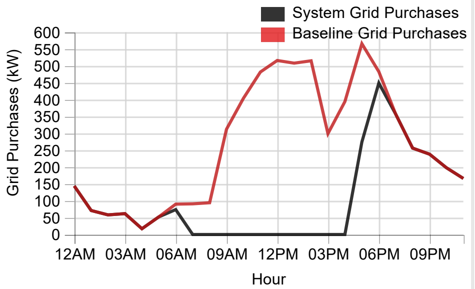


ABRIL

PLOT OF PEAK DAY PV, AND GRID PURCHASES

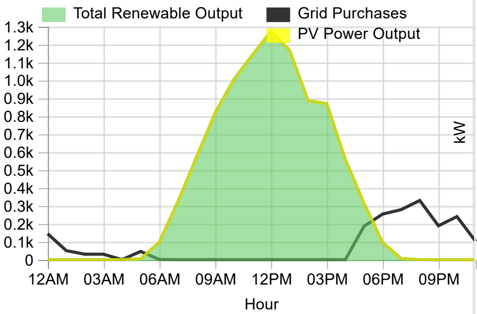


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

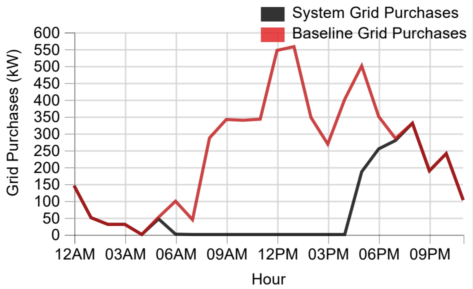


MAYO

PLOT OF PEAK DAY PV, AND GRID PURCHASES

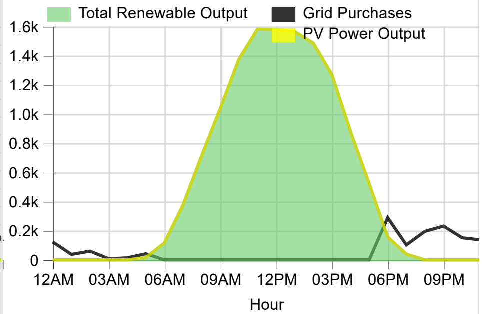


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

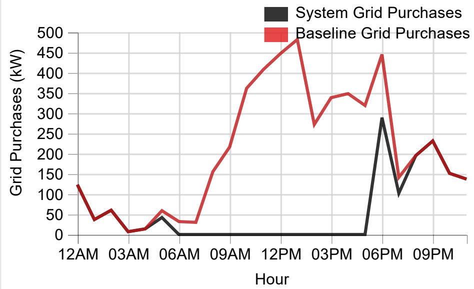


JUNIO

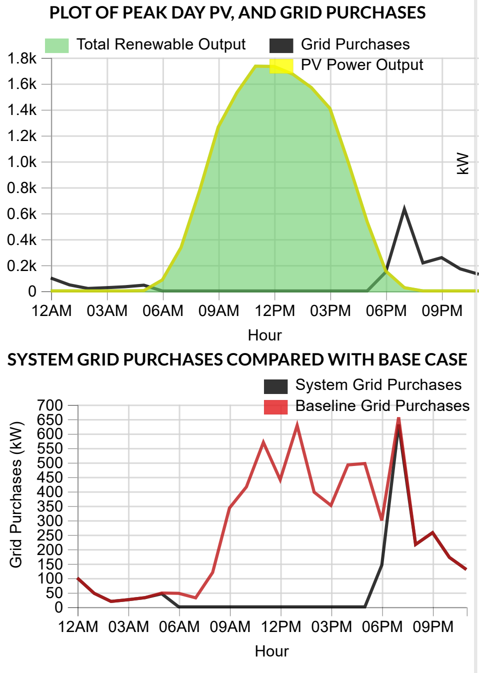
PLOT OF PEAK DAY PV, AND GRID PURCHASES



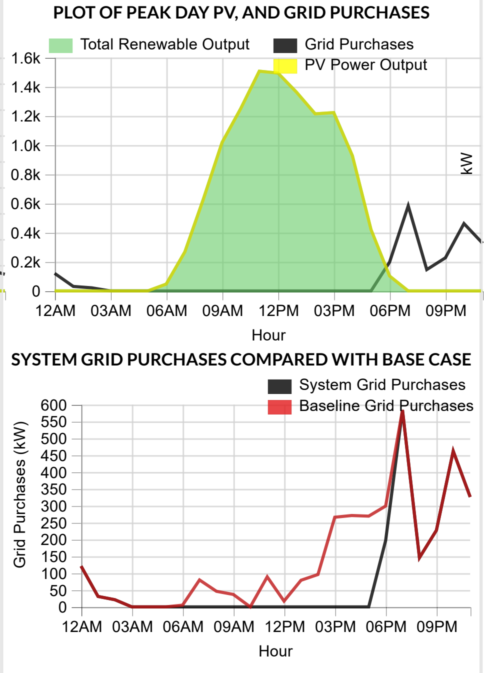
SYSTEM GRID PURCHASES COMPARED WITH BASE CASE



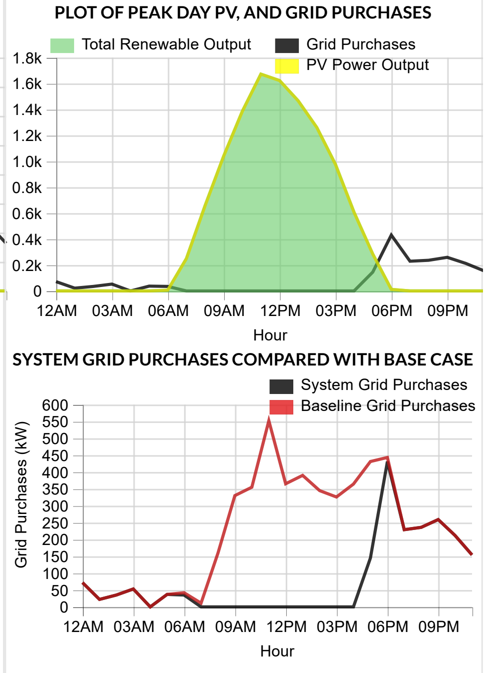
JULIO



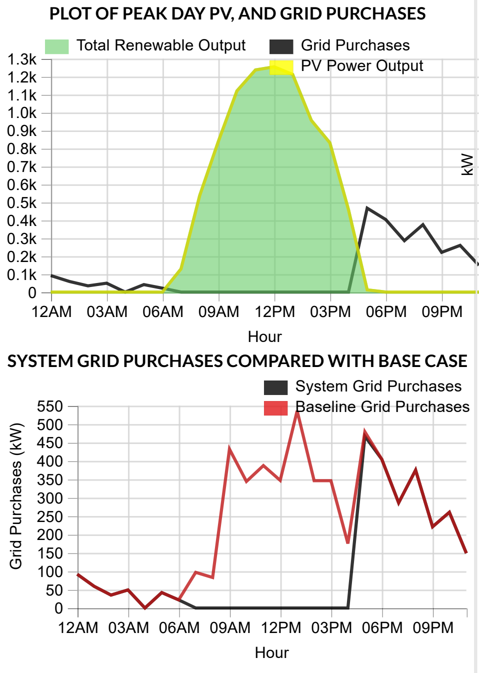
AGOSTO



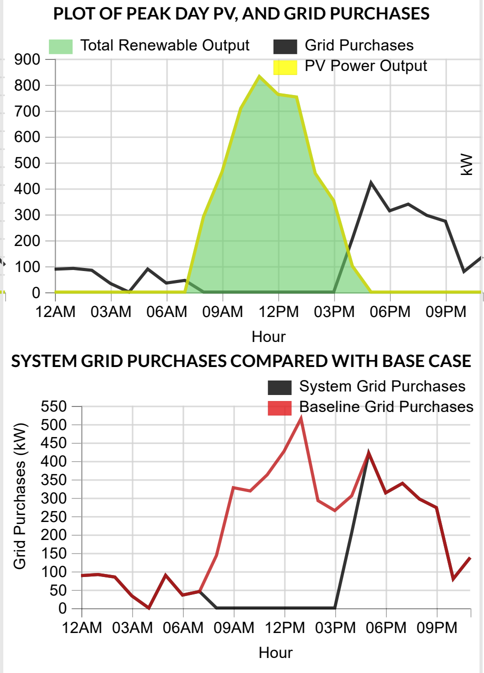
SEPTIEMBRE



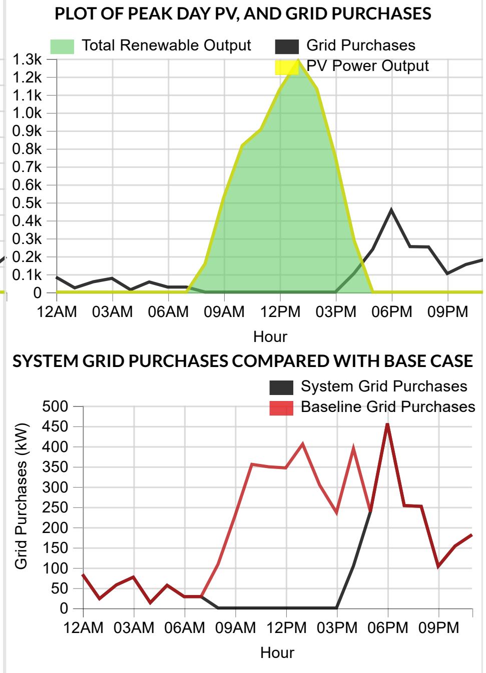
OCTUBRE



NOVIEMBRE



DICIEMBRE



Monthly Carbon Dioxide Emissions: System #1

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	28 t	23 t	21 t	19 t	18 t	14 t	17 t	34 t	20 t	25 t	26 t	28 t
Annual Total (metric tons)	272 t/yr											

* emissions are based on an assumption of your grid's generation sources.

System #2: Solar + Storage: 100LI + MV grid

Savings Overview: Between System #2 (Solar + Storage: 100LI + MV grid) and Base Case

Average annual energy bill savings:	204.129,61 €
CAPEX	1.623.341,00 €
Payback time (simple/discounted):	8,1/11,5 years
Internal Rate of Return (IRR)	10,98%
Project lifetime savings over 20 years:	4.082.592 €

Installation Recommendation: System #2

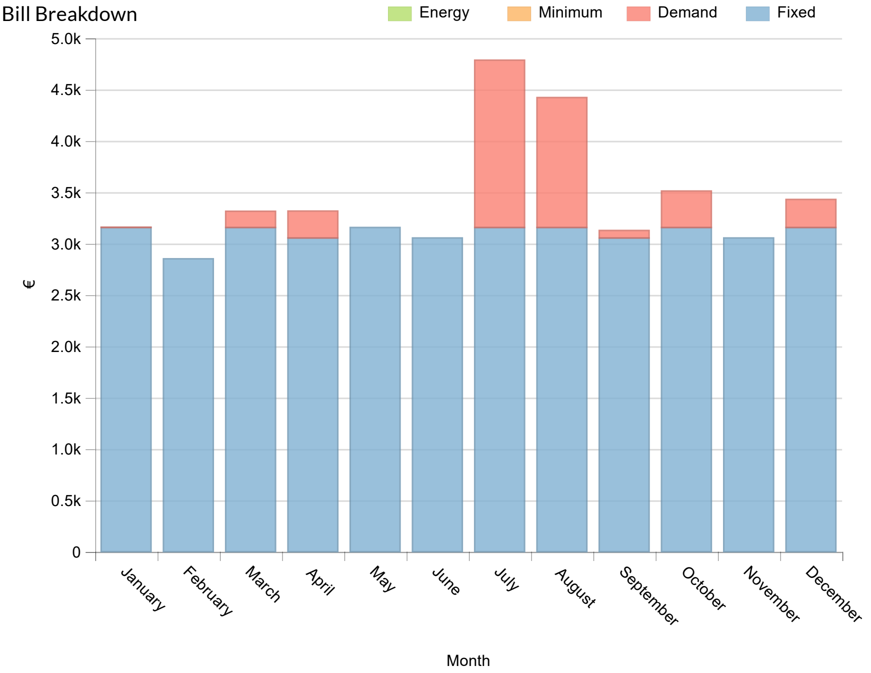
Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Solar PV plant	0,58 €/watt	2,5E+03 kW	1.447.500 €	16.750 €/yr
Generic 100kWh Li-Ion	49.500,00 €/ea.	1 ea.	49.500 €	827 €/yr

Electrical Bill (Predicted): System #2

Tariff: 6.1TD_400kW NT

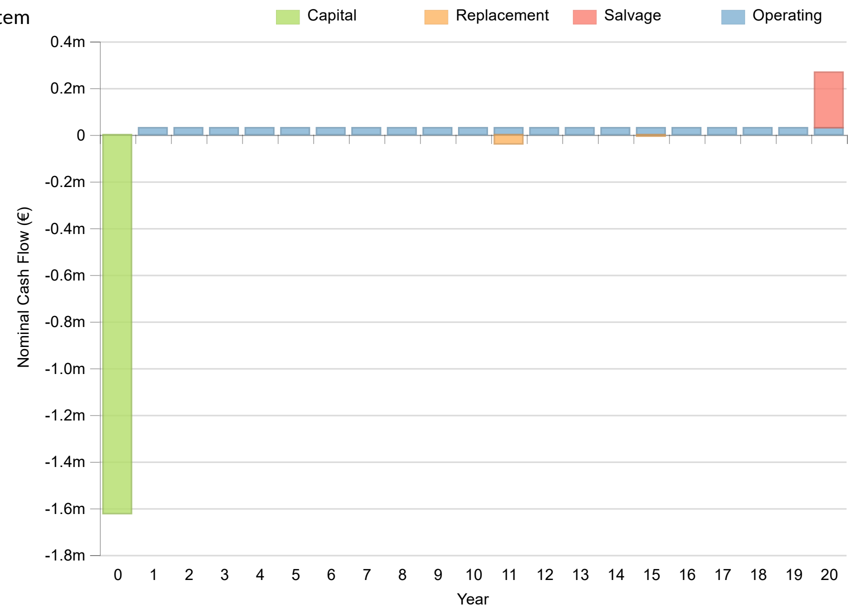
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Energy Charges, Consumption, and Sales	-€1.121	-€2.675	-€8.000	-€9.312	-€10.938	-€12.162	-€13.080	-€10.072	-€9.910	-€7.024	-€2.101	-€1.948
	41.556 kWh	33.855 kWh	30.475 kWh	28.232 kWh	25.618 kWh	20.422 kWh	24.136 kWh	51.643 kWh	29.091 kWh	37.725 kWh	38.419 kWh	42.185 kWh
	105.728 kWh	118.834 kWh	211.256 kWh	228.704 kWh	258.361 kWh	270.448 kWh	298.644 kWh	290.528 kWh	240.545 kWh	198.203 kWh	109.305 kWh	122.213 kWh
Demand Charges and Peak Demand	3 €	0 €	158 €	263 €	0 €	0 €	1.629 €	1.266 €	74 €	356 €	0 €	273 €
	401 kW	400 kW	420 kW	435 kW	384 kW	268 kW	610 kW	563 kW	410 kW	446 kW	400 kW	435 kW
Fixed charges (€)	3.157 €	2.851 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €
Monthly Total	2.039 €	176 €	-€4.685	-€5.995	-€7.782	-€9.107	-€8.295	-€5.650	-€6.781	-€3.512	954 €	1.481 €
Annual Total	-€47.156											

Figure 1: Monthly Electrical Bill Breakdown



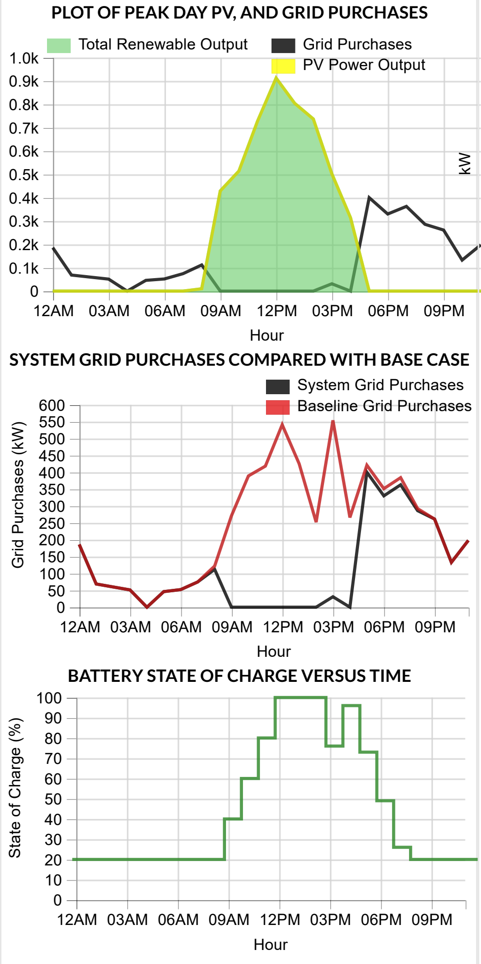
Cash Flow Summary: System #2

Figure 2: Cash Flow for System

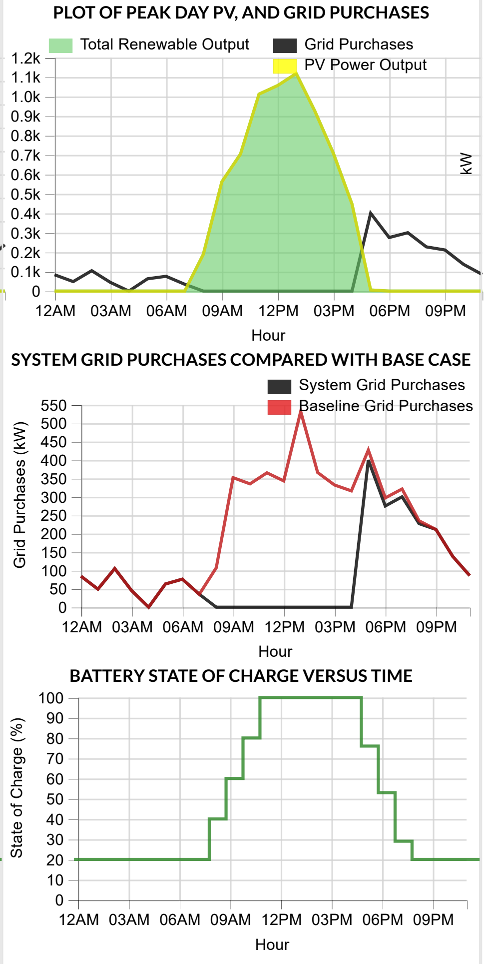


Performance Summary: System #2

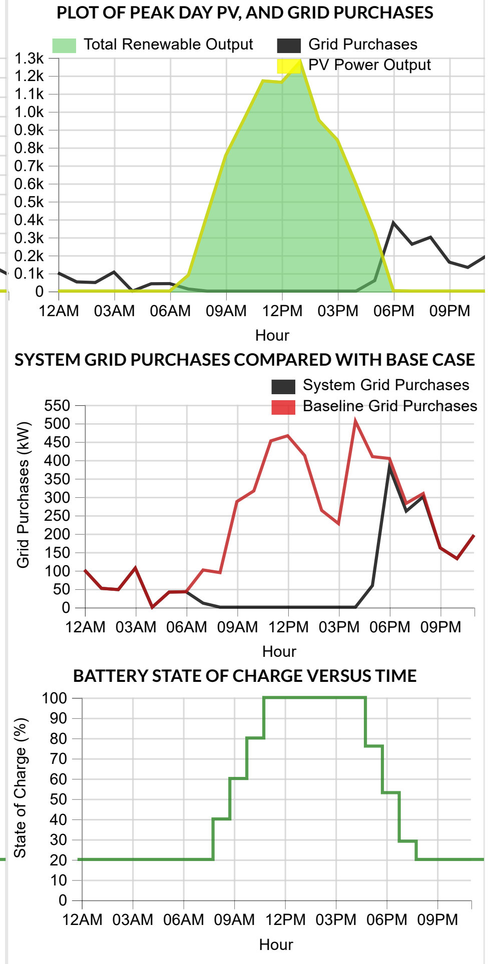
ENERO



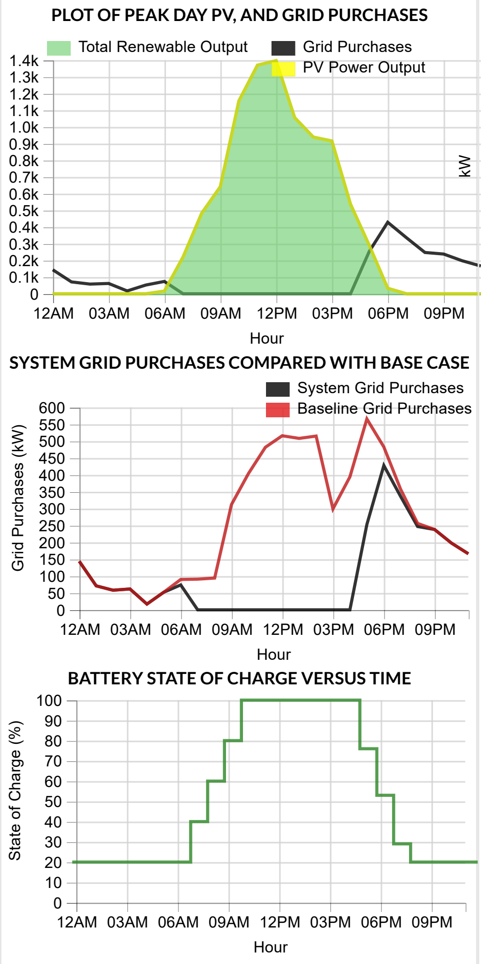
FEBRERO



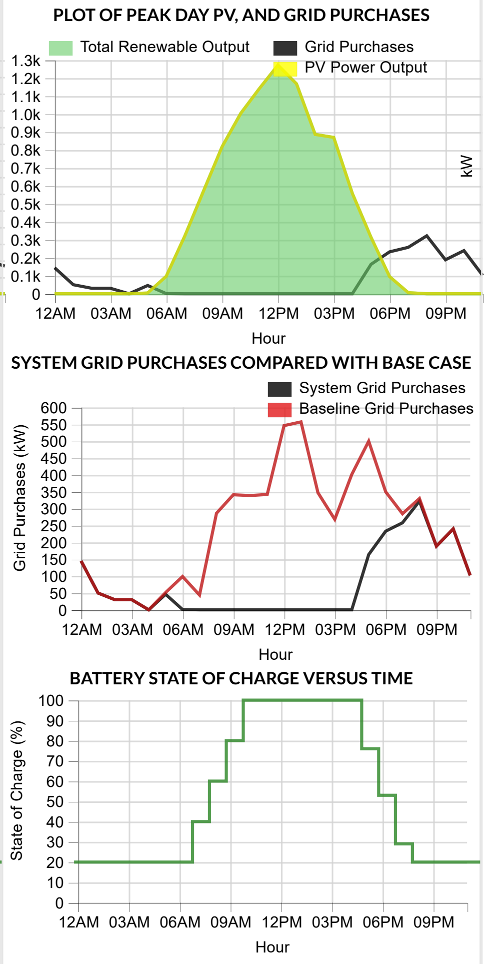
MARZO



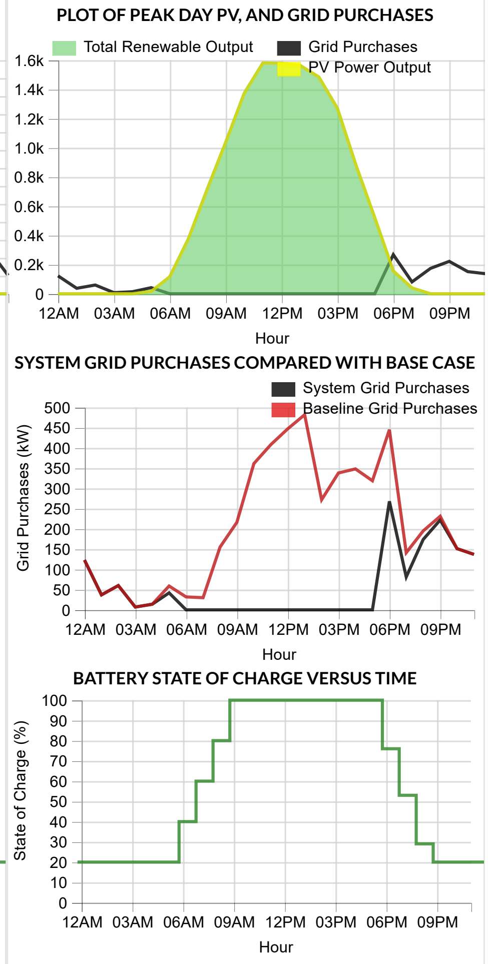
ABRIL



MAYO

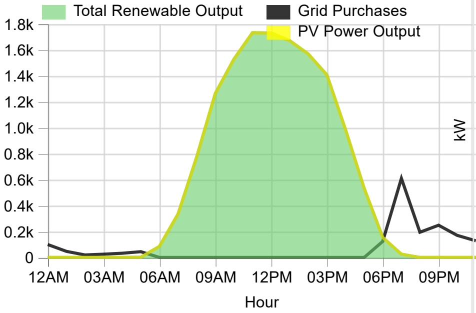


JUNIO

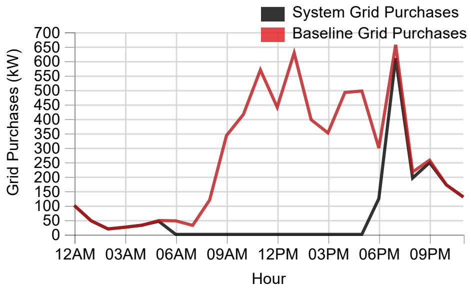


JULIO

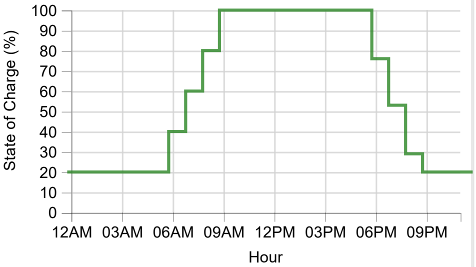
PLOT OF PEAK DAY PV, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

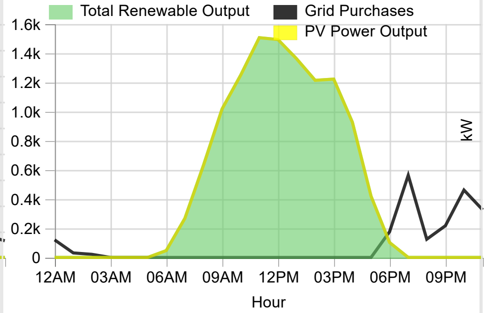


BATTERY STATE OF CHARGE VERSUS TIME

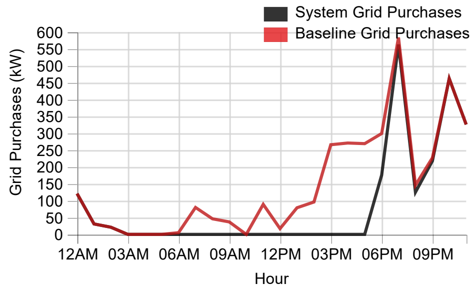


AGOSTO

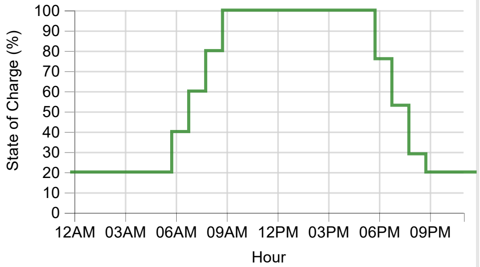
PLOT OF PEAK DAY PV, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

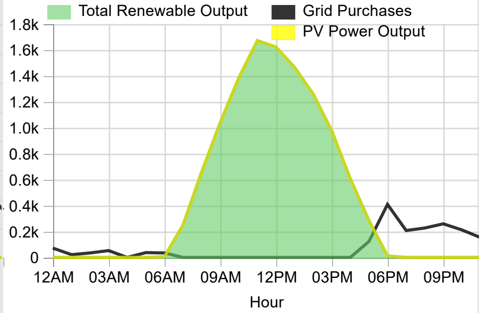


BATTERY STATE OF CHARGE VERSUS TIME

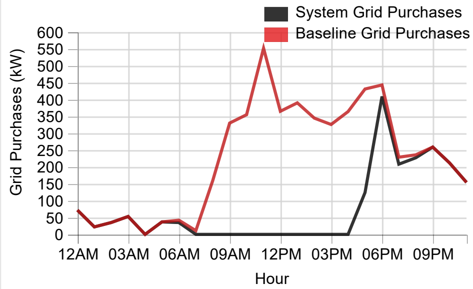


SEPTIEMBRE

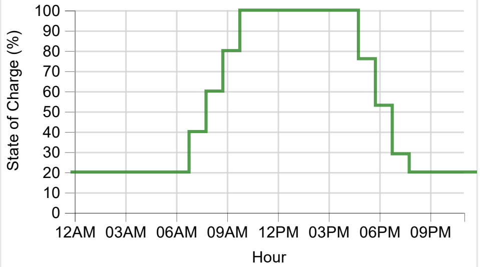
PLOT OF PEAK DAY PV, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

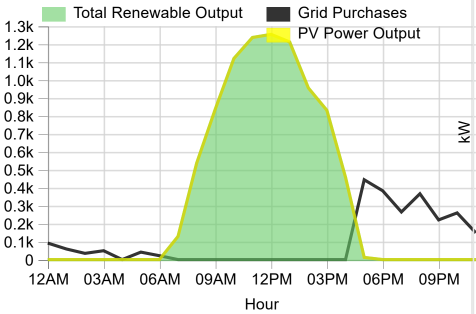


BATTERY STATE OF CHARGE VERSUS TIME

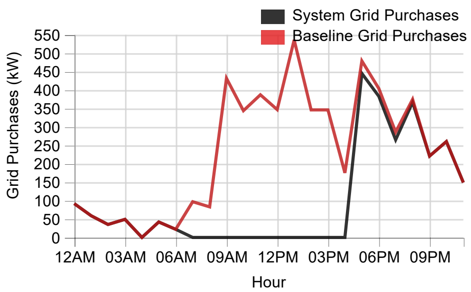


OCTUBRE

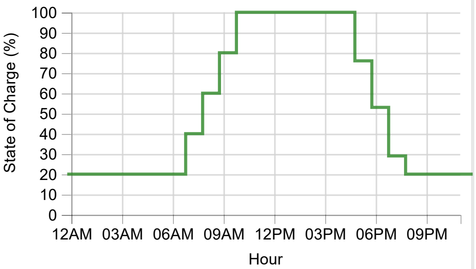
PLOT OF PEAK DAY PV, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

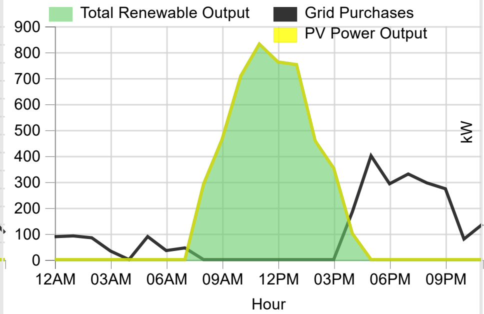


BATTERY STATE OF CHARGE VERSUS TIME

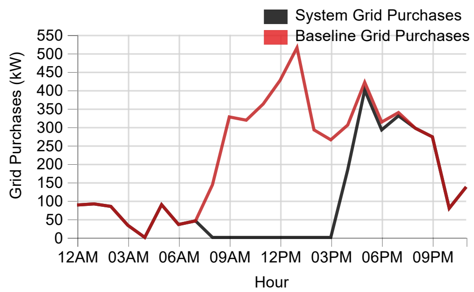


NOVIEMBRE

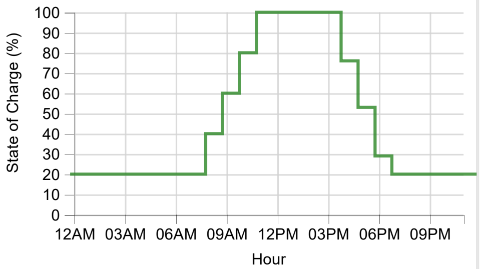
PLOT OF PEAK DAY PV, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

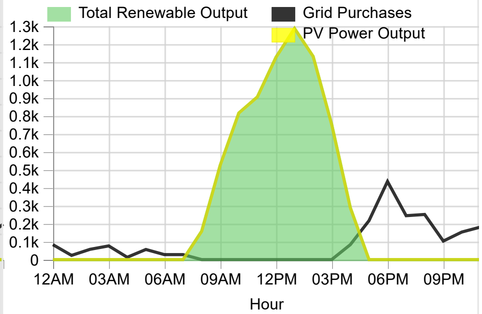


BATTERY STATE OF CHARGE VERSUS TIME

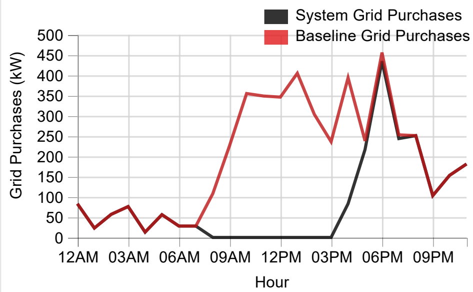


DICIEMBRE

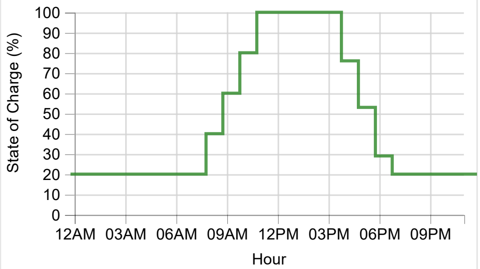
PLOT OF PEAK DAY PV, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE



BATTERY STATE OF CHARGE VERSUS TIME



Monthly Carbon Dioxide Emissions: System #2

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	26 t	21 t	19 t	18 t	16 t	13 t	15 t	33 t	18 t	24 t	24 t	27 t
Annual Total (metric tons)	255 t/yr											

* emissions are based on an assumption of your grid's generation sources.

System #3: Solar + Wind + MV grid

Savings Overview: Between System #3 (Solar + Wind + MV grid) and Base Case

Average annual energy bill savings:	210.895,72 €
CAPEX	1.815.500,00 €
Payback time (simple/discounted):	9,0/13,2 years
Internal Rate of Return (IRR)	9,49%
Project lifetime savings over 20 years:	4.217.914 €

Installation Recommendation: System #3

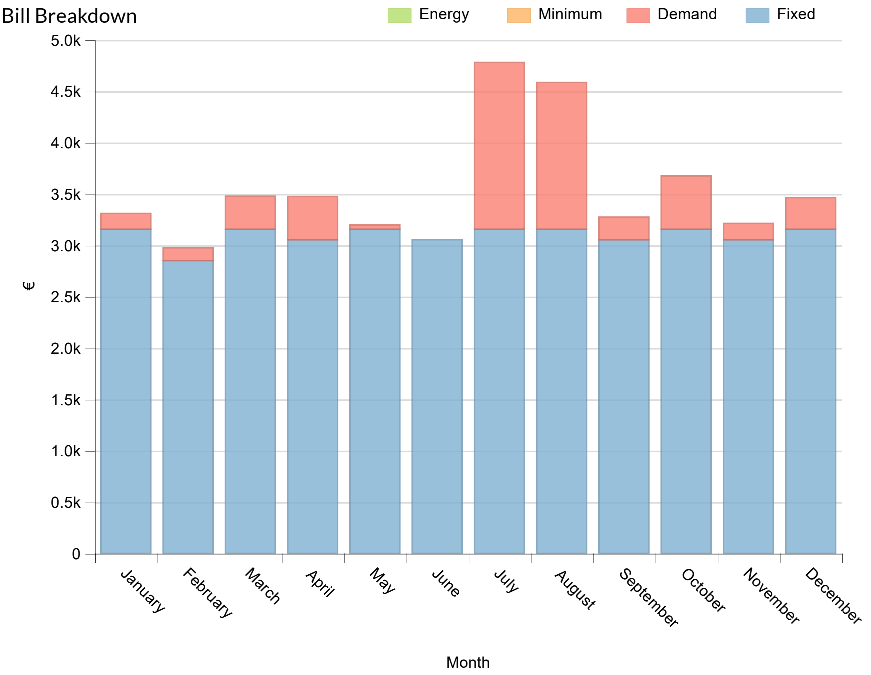
Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Solar PV plant	0,58 €/watt	2,5E+03 kW	1.447.500 €	16.750 €/yr
Wind turbine [250kW]	248.000,00 €/ea	1 ea	248.000 €	6.200 €/yr

Electrical Bill (Predicted): System #3

Tariff: 6.1TD_400kW NT

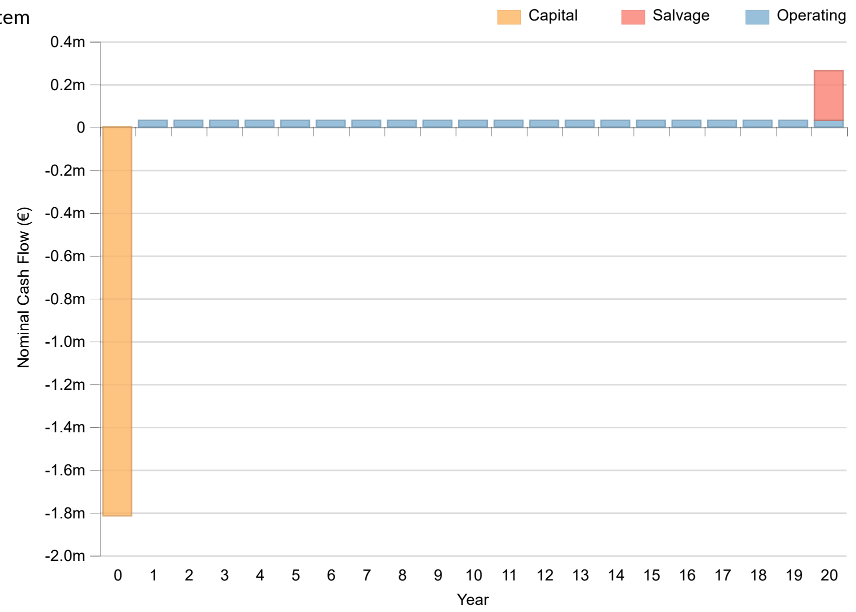
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Energy Charges, Consumption, and Sales	-€1.613	-€3.204	-€8.766	-€9.761	-€11.649	-€12.758	-€13.140	-€10.103	-€10.011	-€7.267	-€3.370	-€4.772
	40.042 kWh	33.502 kWh	29.434 kWh	28.902 kWh	26.328 kWh	20.996 kWh	25.742 kWh	53.421 kWh	30.697 kWh	38.258 kWh	34.865 kWh	30.451 kWh
	116.162 kWh	128.760 kWh	225.296 kWh	238.716 kWh	273.617 kWh	283.312 kWh	303.439 kWh	294.275 kWh	245.425 kWh	204.199 kWh	128.165 kWh	156.691 kWh
Demand Charges and Peak Demand	154 €	125 €	322 €	421 €	42 €	0 €	1.625 €	1.429 €	220 €	520 €	159 €	308 €
	420 kW	418 kW	442 kW	456 kW	405 kW	289 kW	610 kW	584 kW	429 kW	467 kW	421 kW	440 kW
Fixed charges (€)	3.157 €	2.851 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €
Monthly Total	1.698 €	-€229	-€5.287	-€6.285	-€8.451	-€9.703	-€8.359	-€5.517	-€6.736	-€3.591	-€156	-€1.307
Annual Total	-€53.922											

Figure 1: Monthly Electrical Bill Breakdown



Cash Flow Summary: System #3

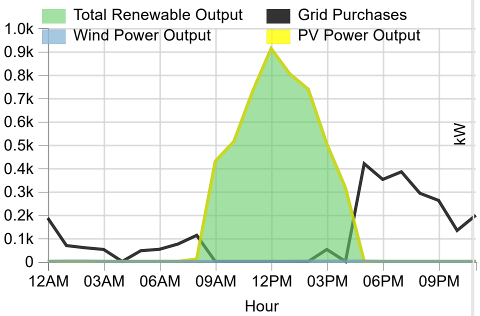
Figure 2: Cash Flow for System



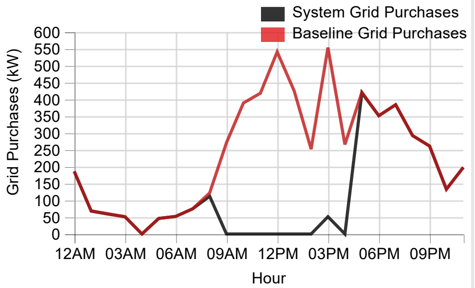
Performance Summary: System #3

ENERO

PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES

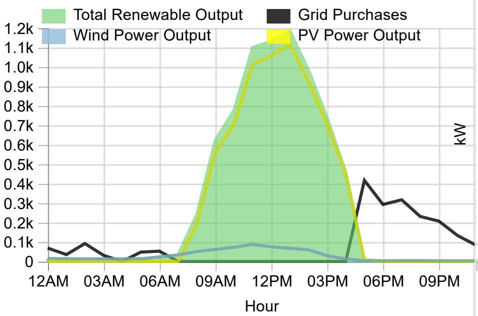


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

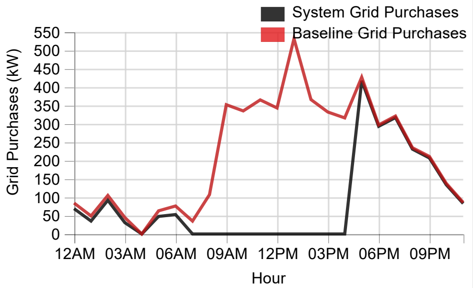


FEBRERO

PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES

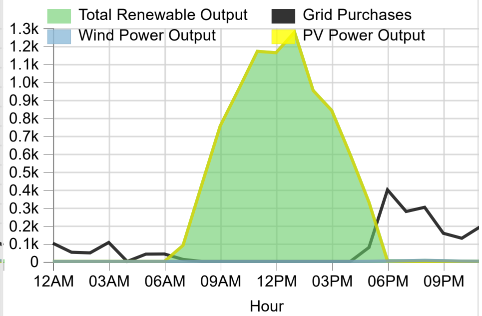


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

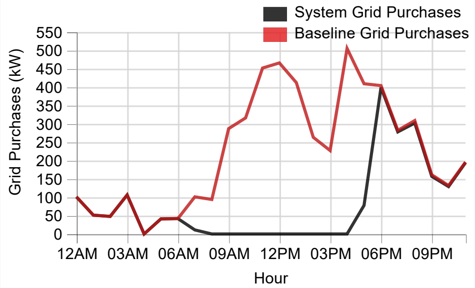


MARZO

PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES

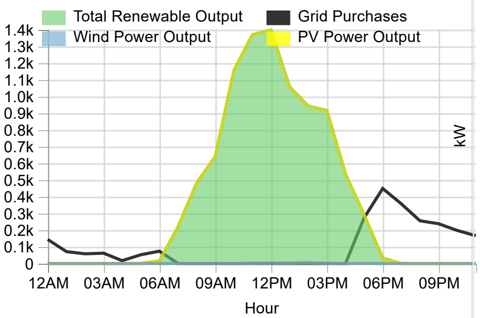


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

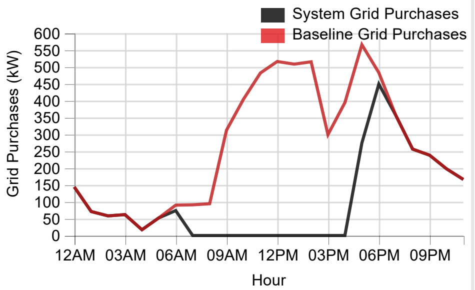


ABRIL

PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES

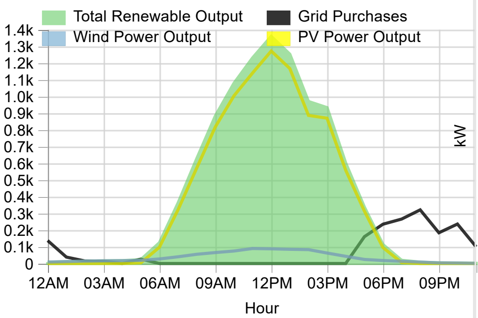


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

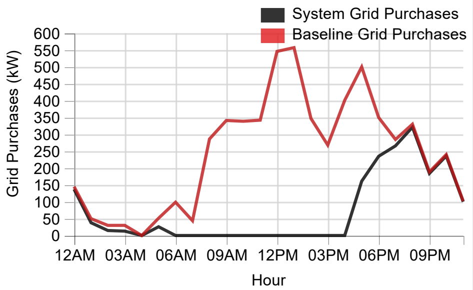


MAYO

PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES

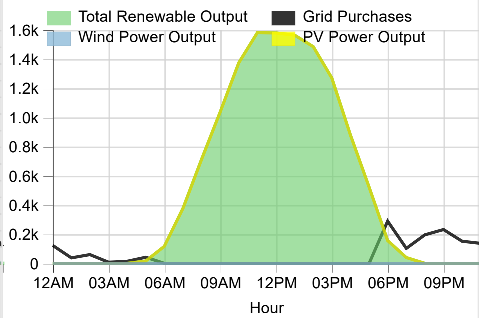


SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

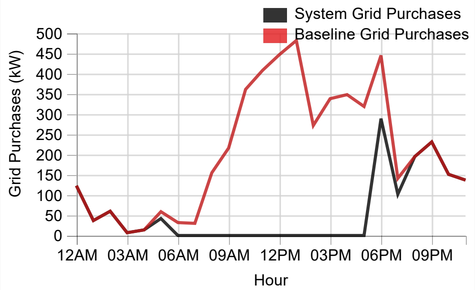


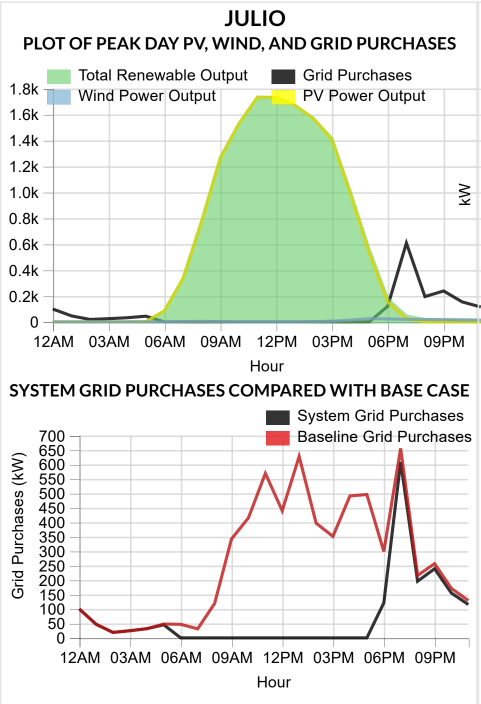
JUNIO

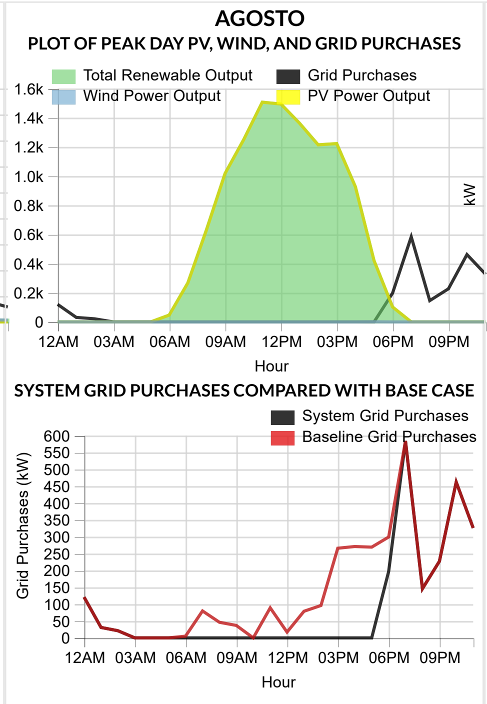
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES

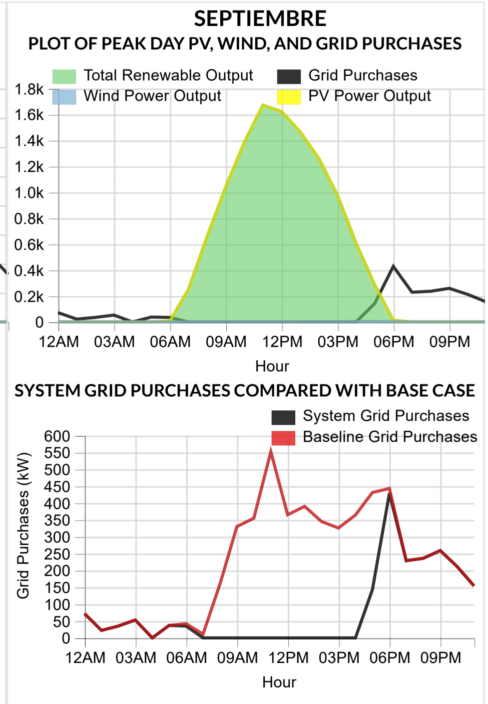


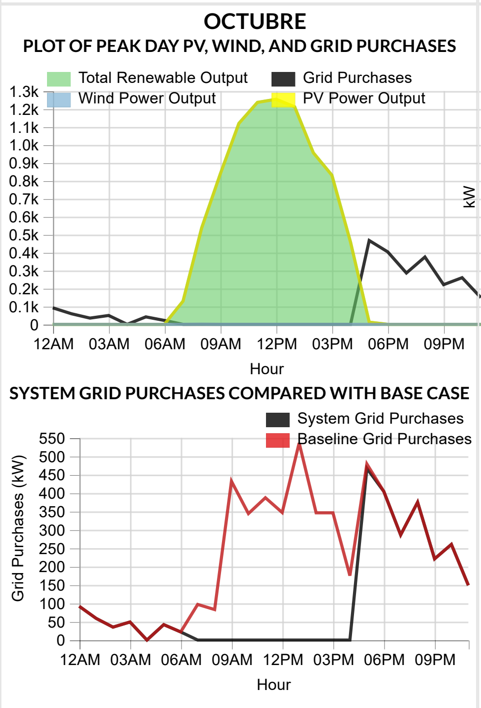
SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

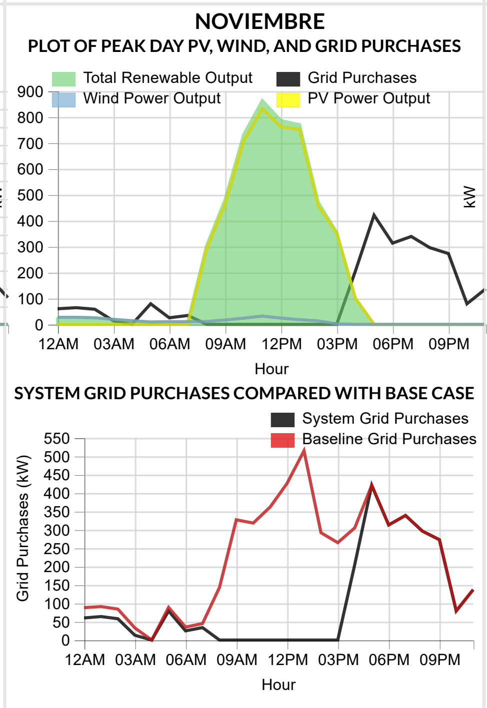


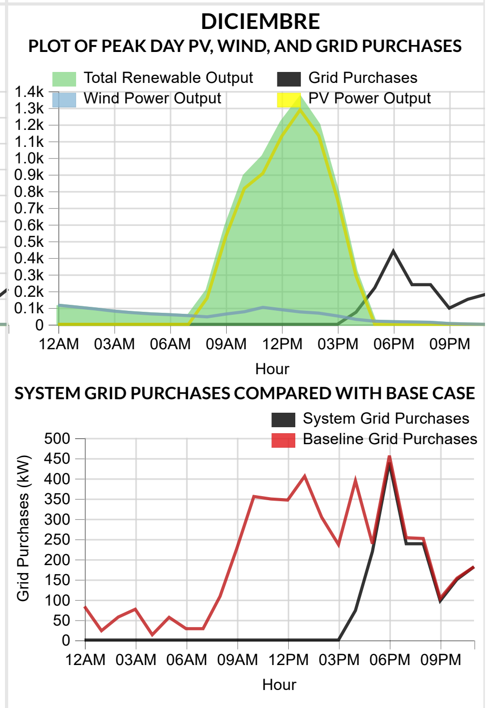












Monthly Carbon Dioxide Emissions: System #3

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	25 t	21 t	19 t	18 t	17 t	13 t	16 t	34 t	19 t	24 t	22 t	19 t
Annual Total (metric tons)	248 t/yr											

* emissions are based on an assumption of your grid's generation sources.

System #4: Solar + Wind + Storage: 100LI + MV grid

Savings Overview: Between System #4 (Solar + Wind + Storage: 100LI + MV grid) and Base Case

Average annual energy bill savings:	209.941,52 €
CAPEX	2.061.205,00 €
Payback time (simple/discounted):	10,9/18,2 years
Internal Rate of Return (IRR)	7,01%
Project lifetime savings over 20 years:	4.198.830 €

Installation Recommendation: System #4

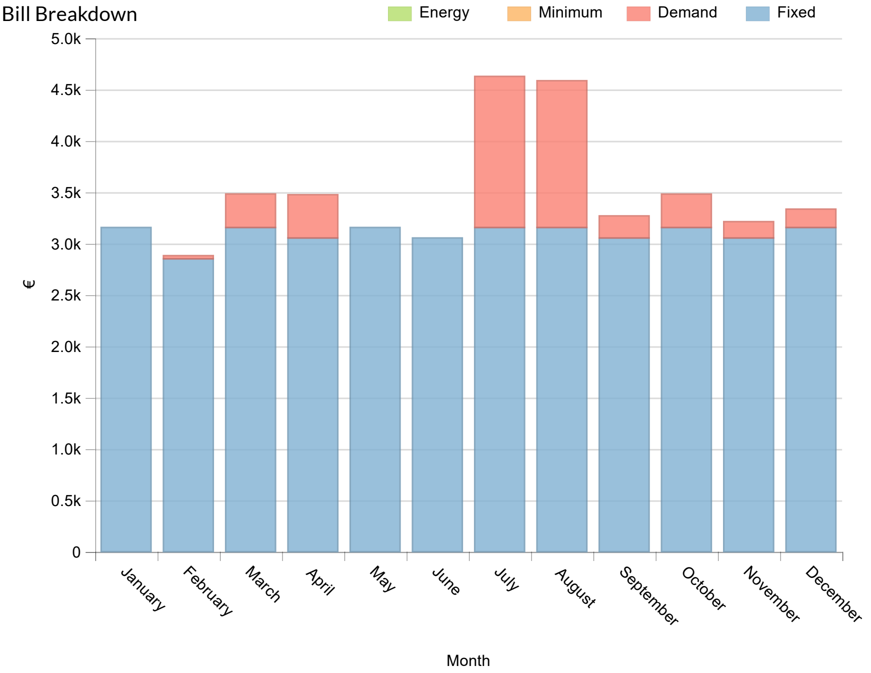
Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Solar PV plant	0,58 €/watt	2,3E+03 kW	1.331.700 €	15.410 €/yr
Wind turbine [250kW]	248.000,00 €/ea	2 ea	496.000 €	12.400 €/yr
Generic 100kWh Li-Ion	49.500,00 €/ea.	1 ea.	49.500 €	827 €/yr

Electrical Bill (Predicted): System #4

Tariff: 6.1TD_400kW NT

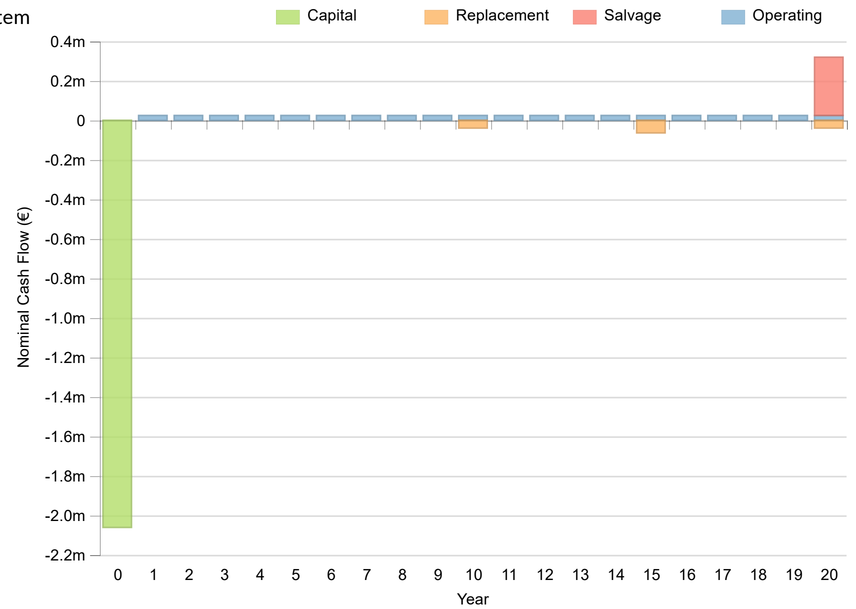
	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	-€1.657	-€3.122	-€8.646	-€9.203	-€11.342	-€12.314	-€12.440	-€9.465	-€9.213	-€6.615	-€3.997	-€6.681
	35.471 kWh	30.341 kWh	26.286 kWh	26.468 kWh	23.147 kWh	18.569 kWh	23.133 kWh	51.109 kWh	28.204 kWh	35.036 kWh	29.837 kWh	22.745 kWh
	109.103 kWh	120.550 kWh	216.683 kWh	223.210 kWh	261.933 kWh	270.312 kWh	284.196 kWh	277.269 kWh	225.403 kWh	185.889 kWh	130.896 kWh	179.551 kWh
Demand Charges and Peak Demand	0 €	32 €	326 €	421 €	0 €	0 €	1.472 €	1.429 €	216 €	326 €	159 €	180 €
	397 kW	405 kW	442 kW	456 kW	340 kW	234 kW	590 kW	584 kW	429 kW	442 kW	421 kW	423 kW
Fixed charges (€)	3.157 €	2.851 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €
Monthly Total	1.499 €	-€239	-€5.163	-€5.727	-€8.185	-€9.260	-€7.811	-€4.879	-€5.943	-€3.133	-€783	-€3.345
Annual Total	-€52.968											

Figure 1: Monthly Electrical Bill Breakdown



Cash Flow Summary: System #4

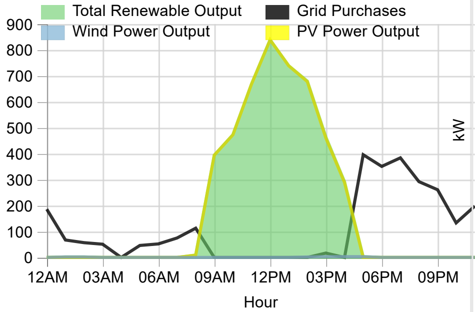
Figure 2: Cash Flow for System



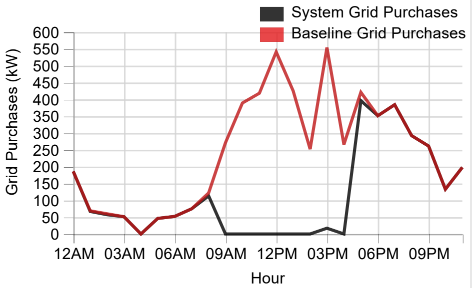
Performance Summary: System #4

ENERO

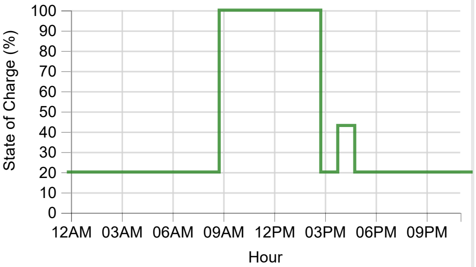
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

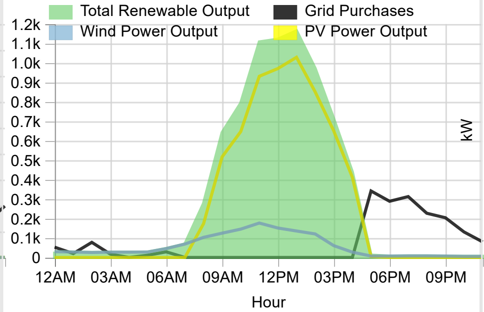


BATTERY STATE OF CHARGE VERSUS TIME

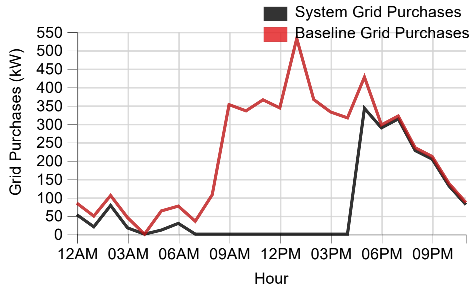


FEBRERO

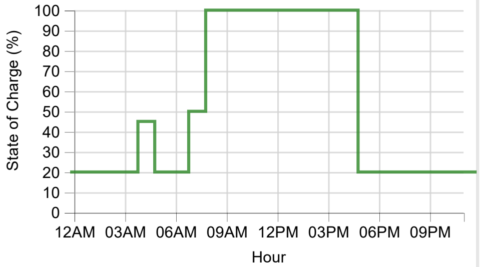
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

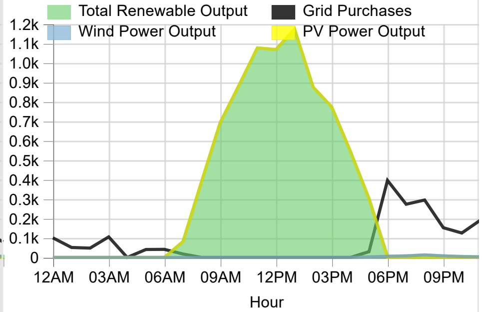


BATTERY STATE OF CHARGE VERSUS TIME

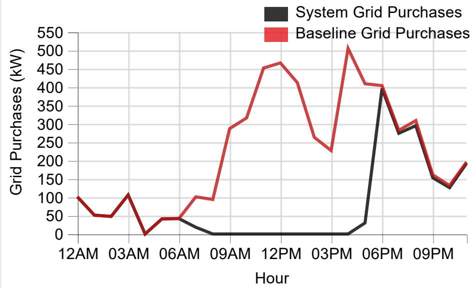


MARZO

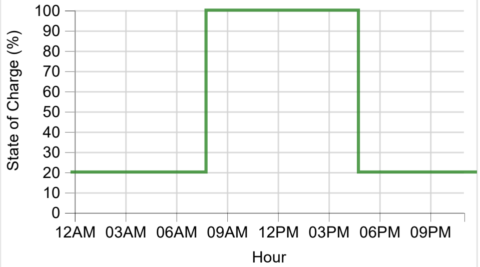
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

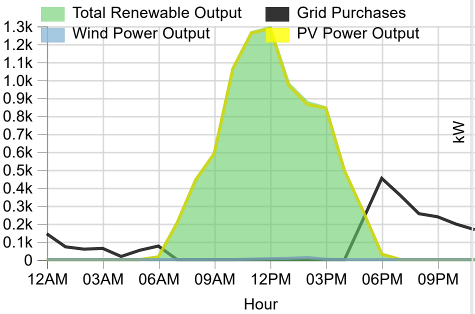


BATTERY STATE OF CHARGE VERSUS TIME

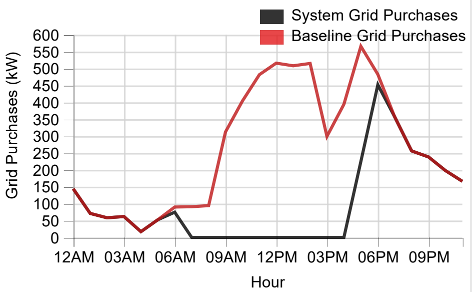


ABRIL

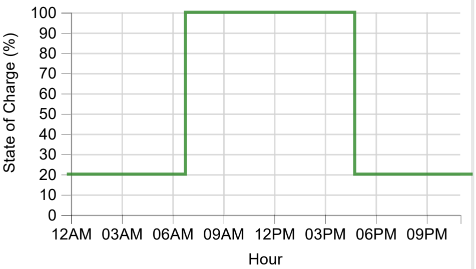
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

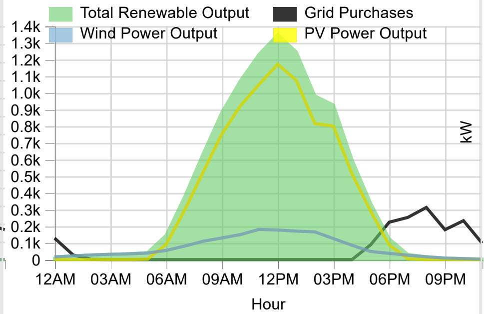


BATTERY STATE OF CHARGE VERSUS TIME

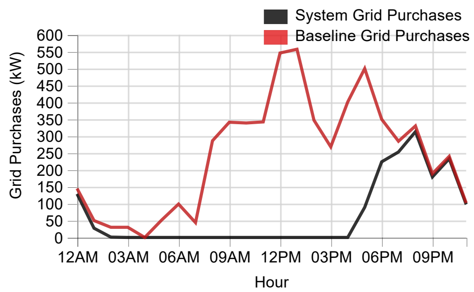


MAYO

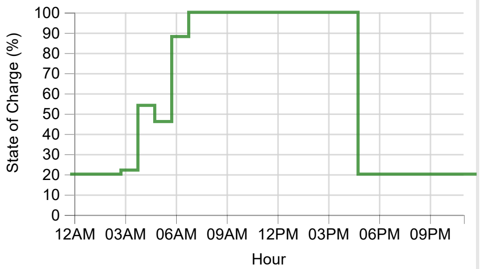
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

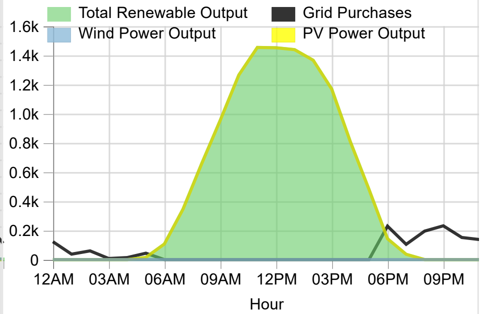


BATTERY STATE OF CHARGE VERSUS TIME

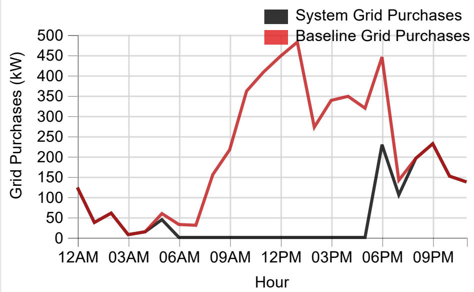


JUNIO

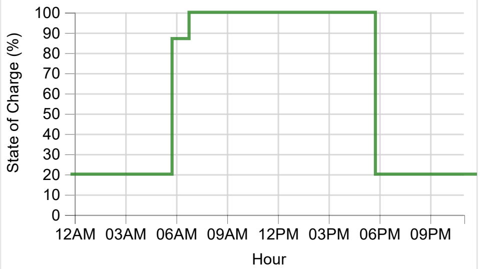
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

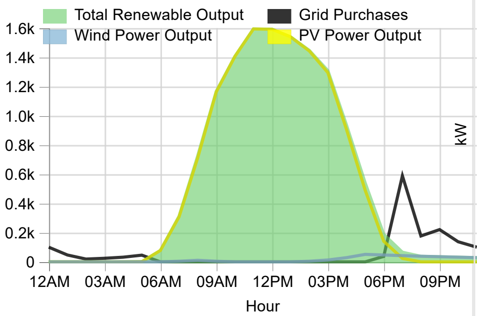


BATTERY STATE OF CHARGE VERSUS TIME

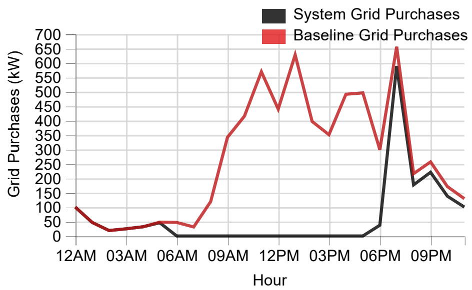


JULIO

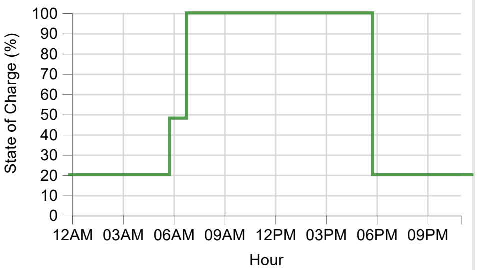
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

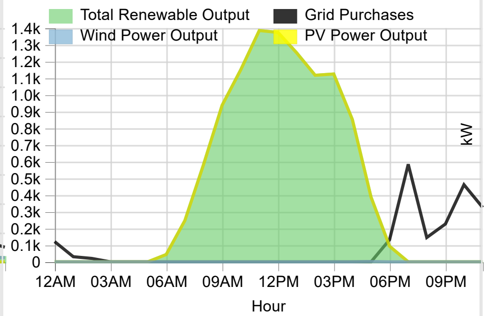


BATTERY STATE OF CHARGE VERSUS TIME

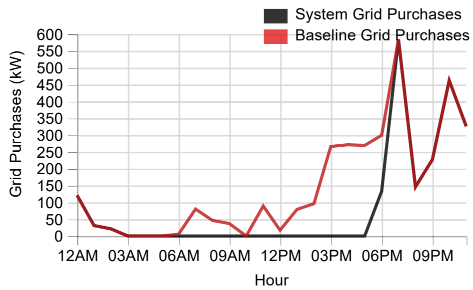


AGOSTO

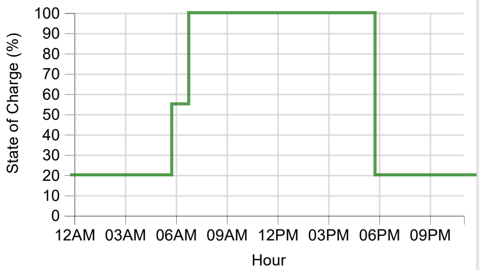
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

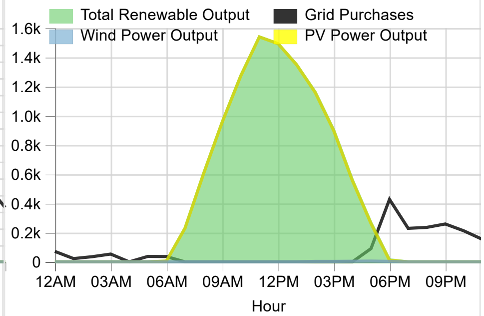


BATTERY STATE OF CHARGE VERSUS TIME

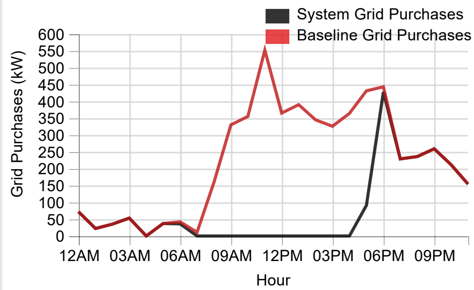


SEPTIEMBRE

PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE



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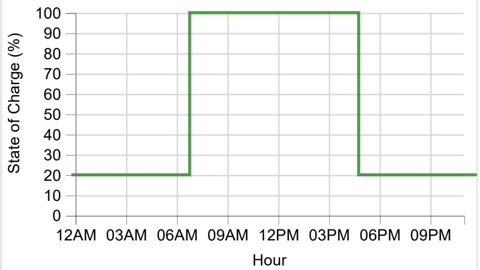
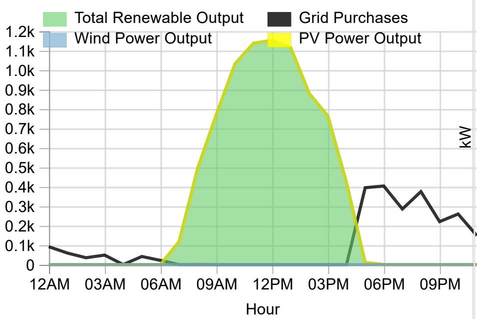


OCTUBRE

PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



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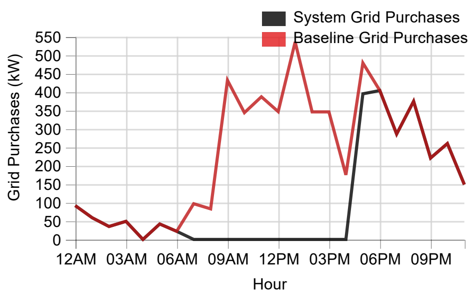

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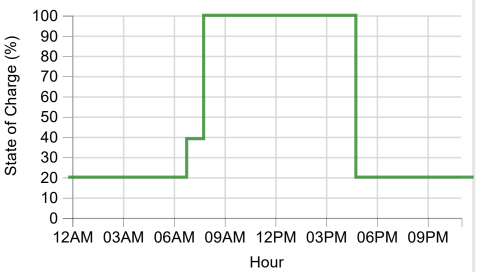

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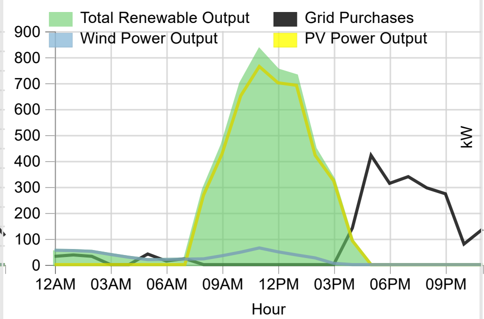
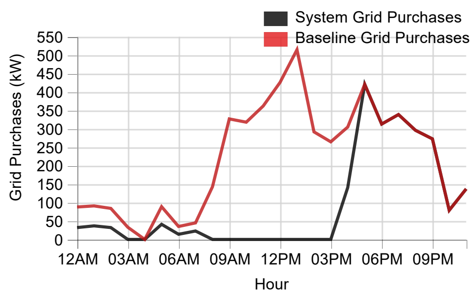
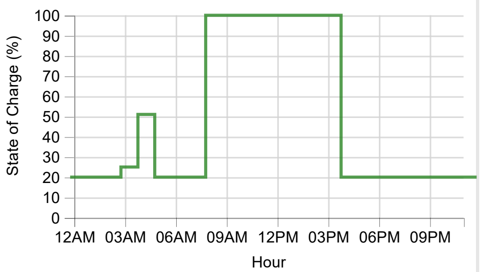
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

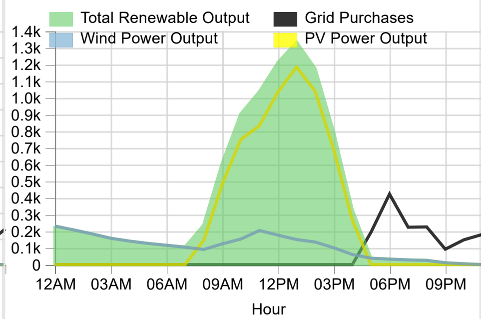


BATTERY STATE OF CHARGE VERSUS TIME

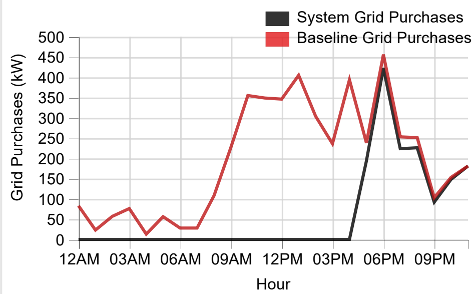


DICIEMBRE

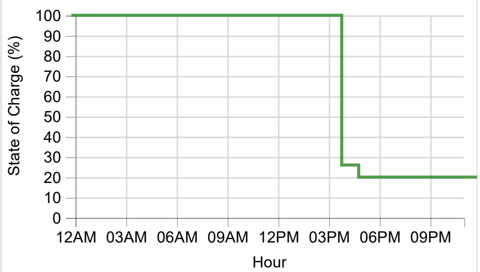
PLOT OF PEAK DAY PV, WIND, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE



BATTERY STATE OF CHARGE VERSUS TIME



Monthly Carbon Dioxide Emissions: System #4

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	22 t	19 t	17 t	17 t	15 t	12 t	15 t	32 t	18 t	22 t	19 t	14 t
Annual Total (metric tons)	221 t/yr											

* emissions are based on an assumption of your grid's generation sources.

System #5: Storage: 100LI + MV grid

Savings Overview: Between System #5 (Storage: 100LI + MV grid) and Base Case

Average annual energy bill savings:	4.935,80 €
CAPEX	189.193,80 €
Payback time (simple/discounted):	n/a
Internal Rate of Return (IRR)	n/a
Project lifetime savings over 20 years:	98.716 €

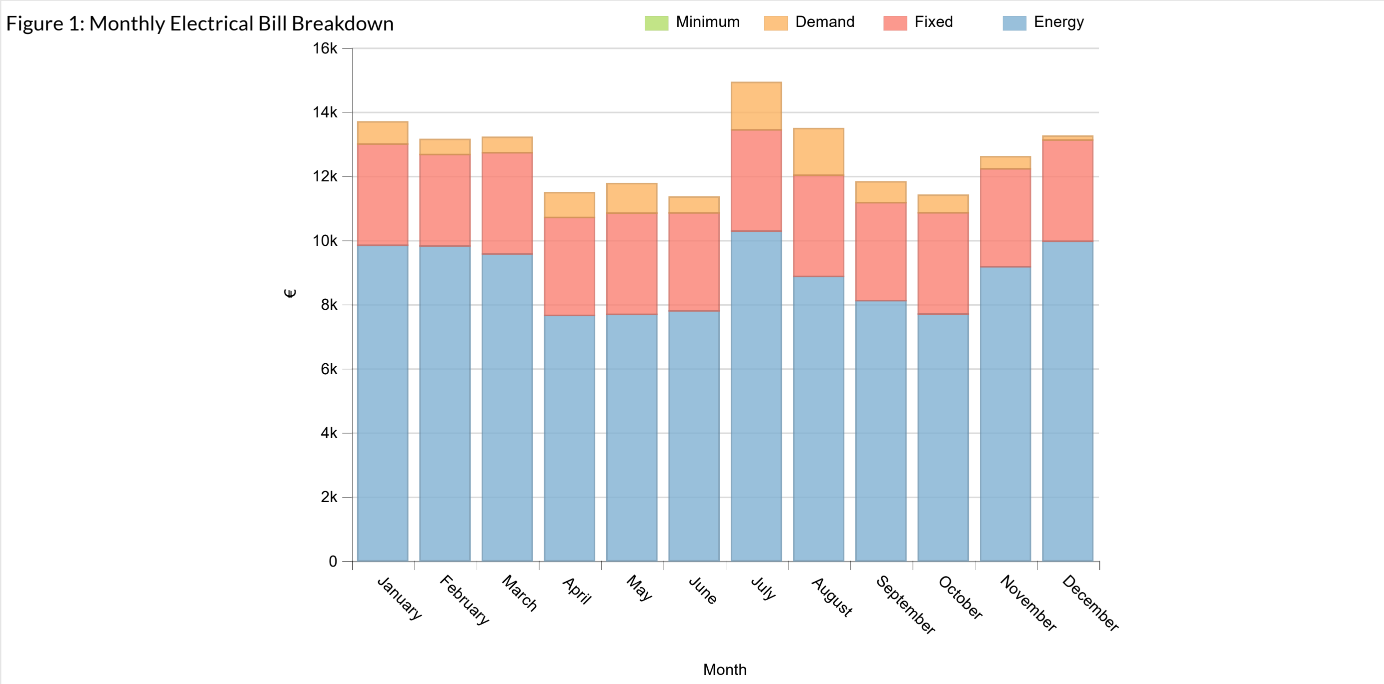
Installation Recommendation: System #5

Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Generic 100kWh Li-Ion	49.500,00 €/ea.	1 ea.	49.500 €	827 €/yr

Electrical Bill (Predicted): System #5

Tariff: 6.1TD_400kW NT

	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	9.836 €	9.815 €	9.565 €	7.649 €	7.682 €	7.791 €	10.278 €	8.864 €	8.110 €	7.694 €	9.167 €	9.962 €
	102.485 kWh	94.261 kWh	102.248 kWh	101.366 kWh	102.049 kWh	93.471 kWh	103.543 kWh	108.988 kWh	97.757 kWh	102.913 kWh	97.247 kWh	99.208 kWh
	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh
Demand Charges and Peak Demand	690 €	471 €	481 €	773 €	920 €	495 €	1.478 €	1.453 €	649 €	549 €	376 €	121 €
	489 kW	467 kW	462 kW	503 kW	519 kW	466 kW	591 kW	588 kW	487 kW	471 kW	450 kW	416 kW
Fixed charges (€)	3.157 €	2.851 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €	3.157 €	3.055 €	3.157 €	3.055 €	3.157 €
Monthly Total	13.683 €	13.137 €	13.203 €	11.477 €	11.759 €	11.341 €	14.913 €	13.474 €	11.814 €	11.399 €	12.598 €	13.239 €
Annual Total	152.038 €											

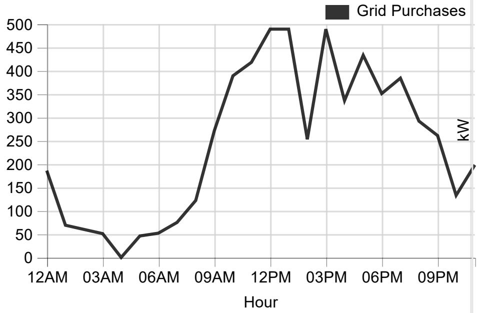


Cash Flow Summary: System #5

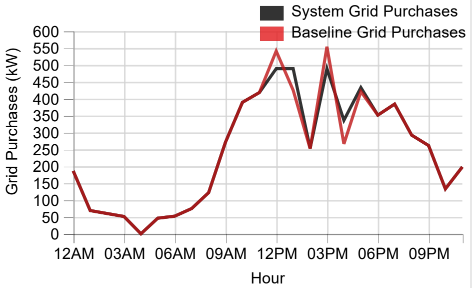
Performance Summary: System #5

ENERO

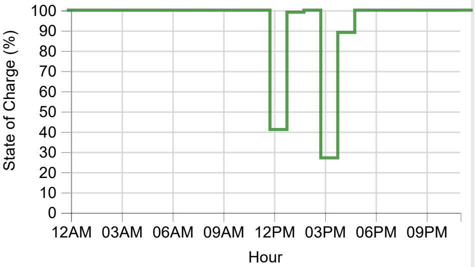
PLOT OF PEAK DAY GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE



BATTERY STATE OF CHARGE VERSUS TIME



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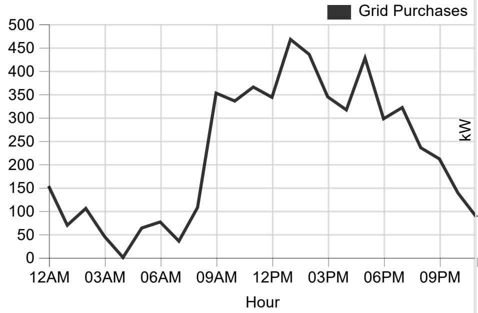
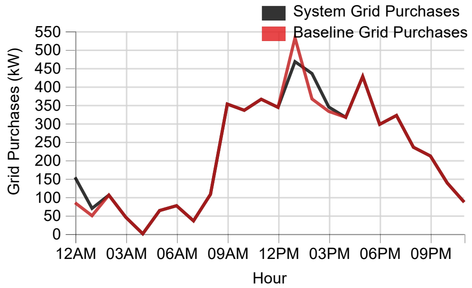
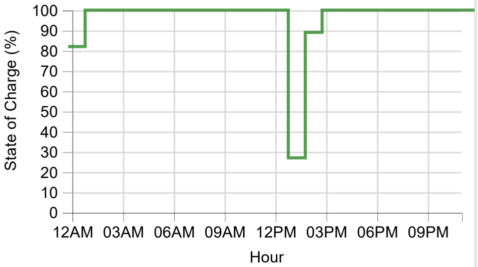
PLOT OF PEAK DAY GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

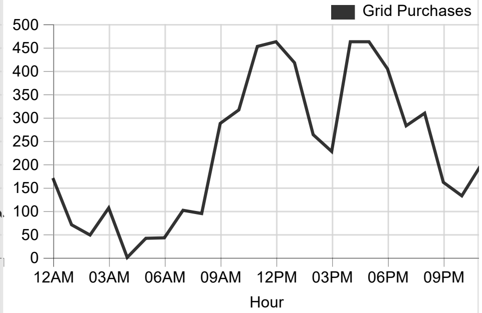


BATTERY STATE OF CHARGE VERSUS TIME

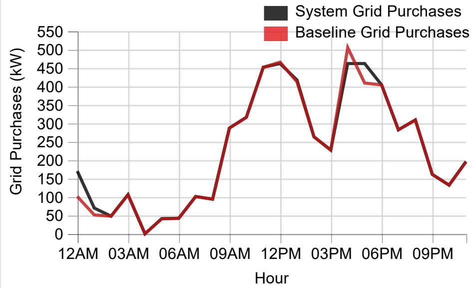


MARZO

PLOT OF PEAK DAY GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE



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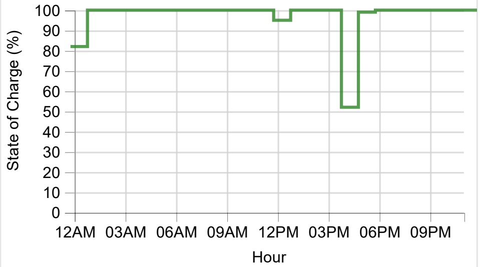

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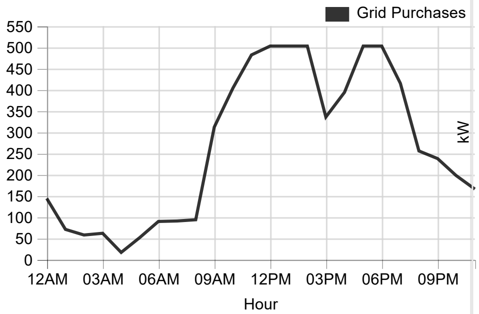
PLOT OF PEAK DAY GRID PURCHASES



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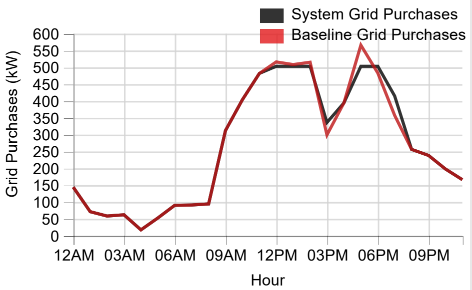

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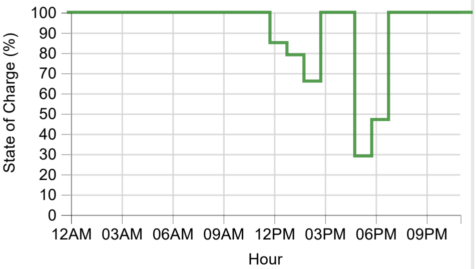

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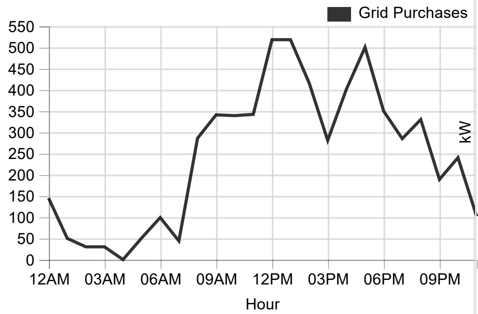

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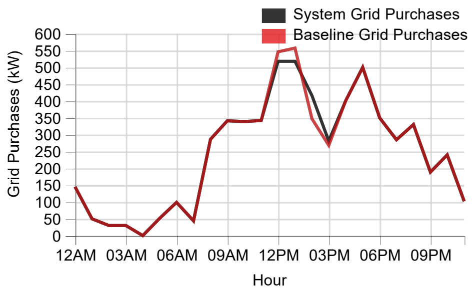

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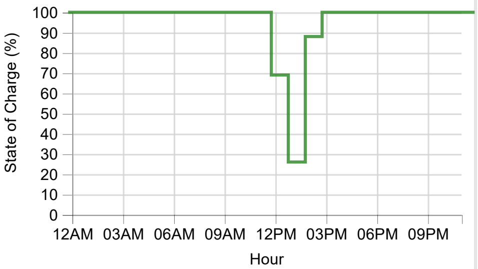
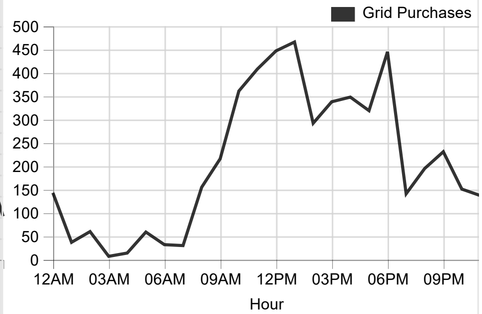


JUNIO

PLOT OF PEAK DAY GRID PURCHASES



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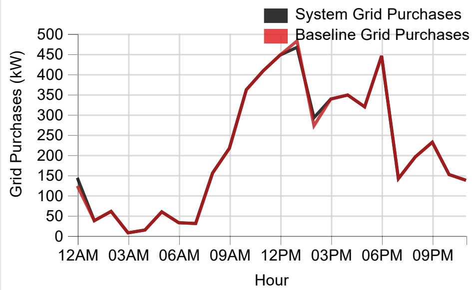

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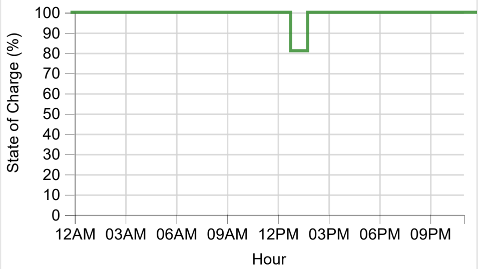

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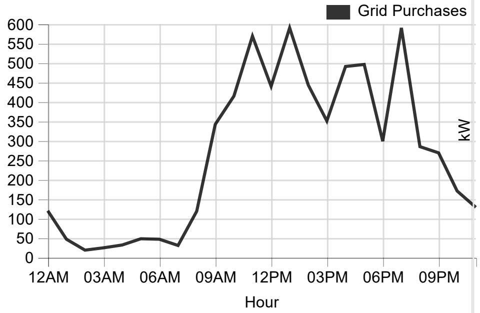

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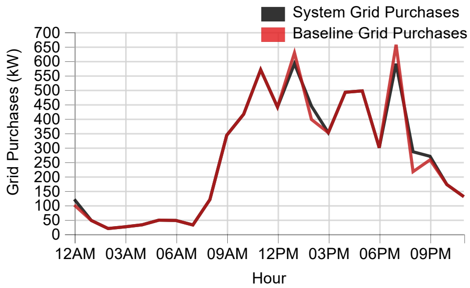

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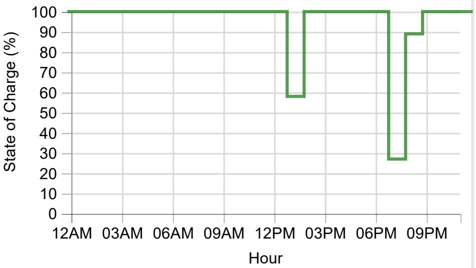

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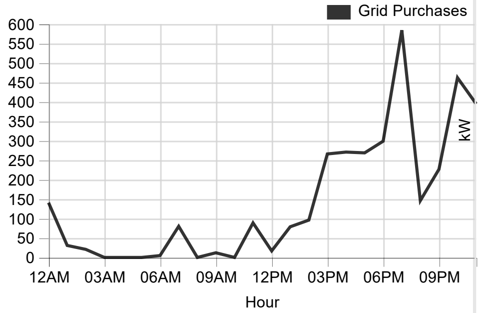

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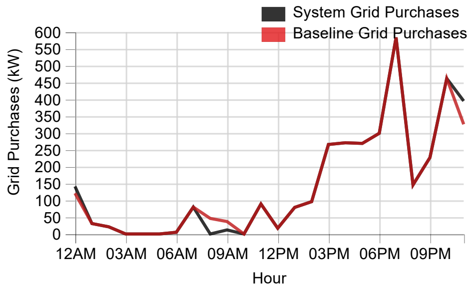

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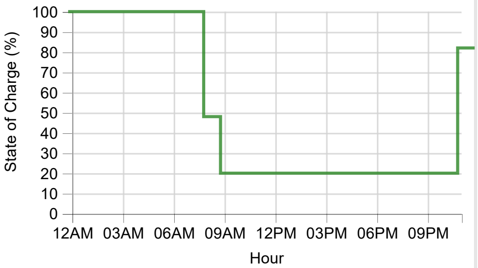

SEPTIEMBRE

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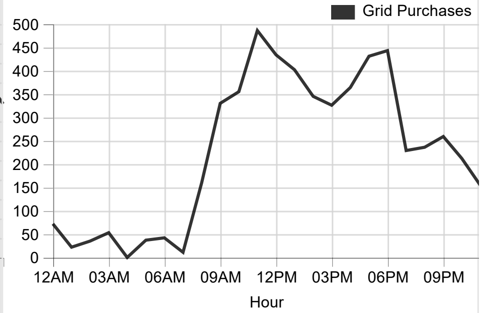

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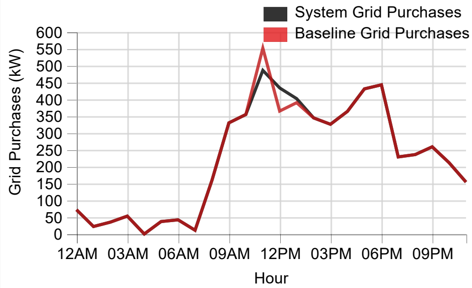

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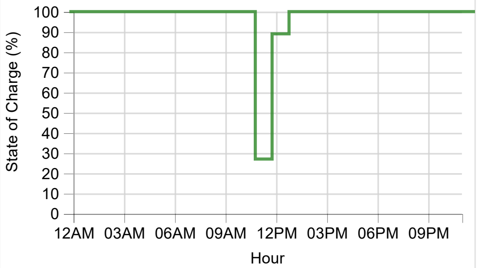

OCTUBRE

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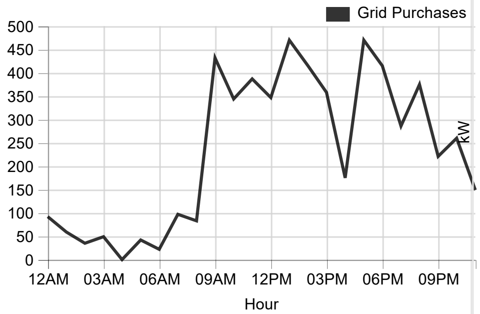

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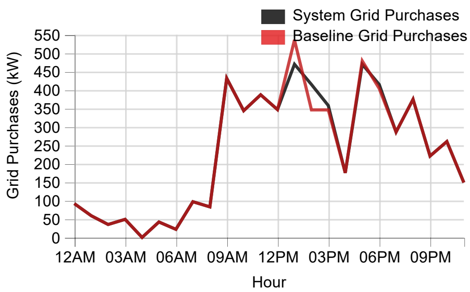

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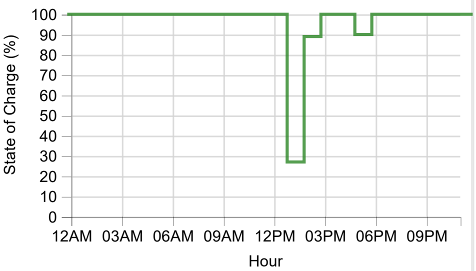

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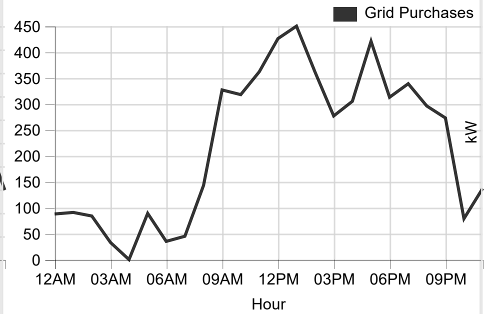

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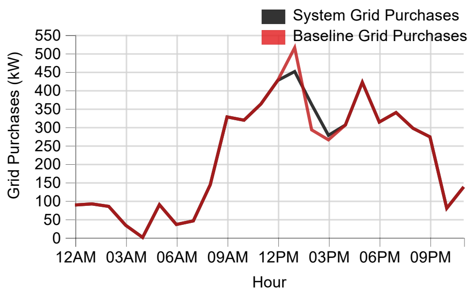

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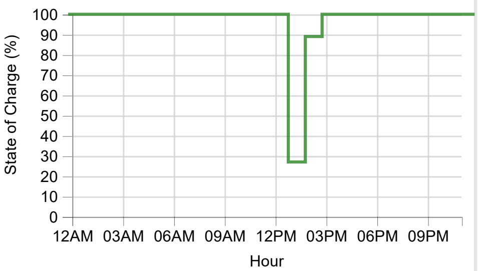

DICIEMBRE

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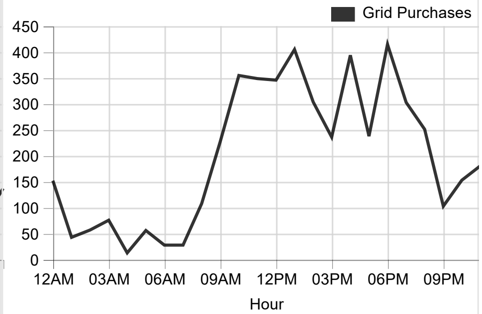

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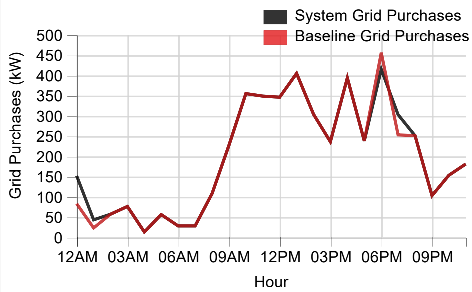

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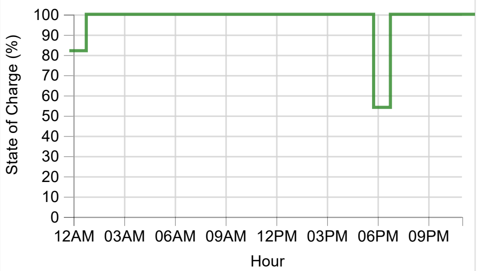


Monthly Carbon Dioxide Emissions: System #5

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	65 t	60 t	65 t	64 t	64 t	59 t	65 t	69 t	62 t	65 t	61 t	63 t
Annual Total (metric tons)	762 t/yr											

* emissions are based on an assumption of your grid's generation sources.

HOMER Grid

HOMER Grid Report

Table of Contents

Site Information

Location	JÖRLANDA BERG 302, 444 93 Spekeröd, Sweden
Latitude	58 degrees 1,49 minutes N
Longitude	11 degrees 50,83 minutes E
Time zone	Europe/Stockholm

Average Electric Energy Consumption:

Daily	Monthly	Annual
3.382,8 kWh/day	102,9 MWh/month	1.234,7 MWh

Annual Peak Electric Demand:

2 de agosto / 861,00 kW

Figure 1: Load Profile for the Day on Which the Largest Demand Occurs (3 de agosto)

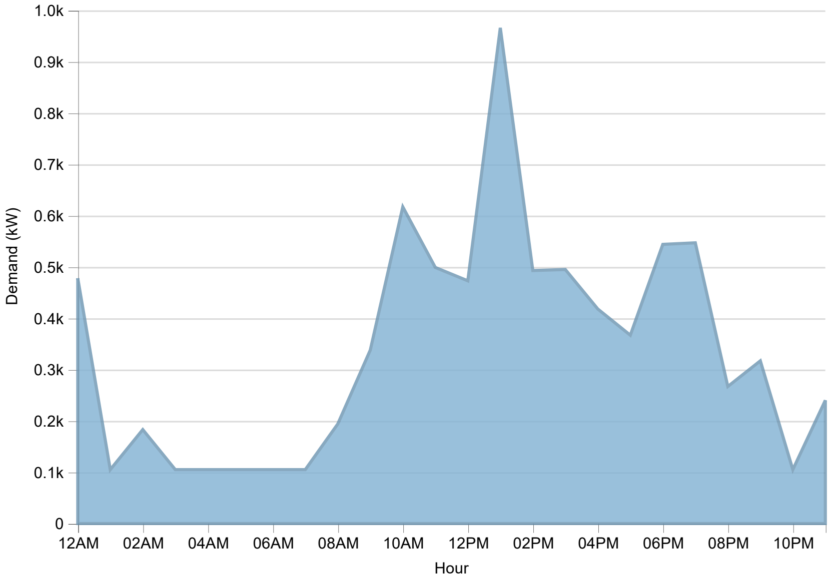
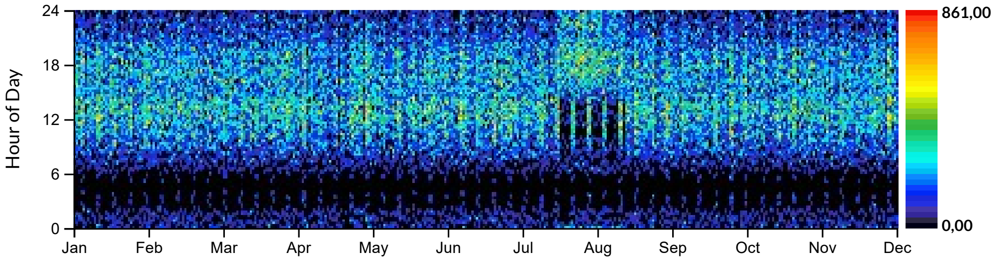


Figure 2: Heat Map, showing Energy Consumption Patterns

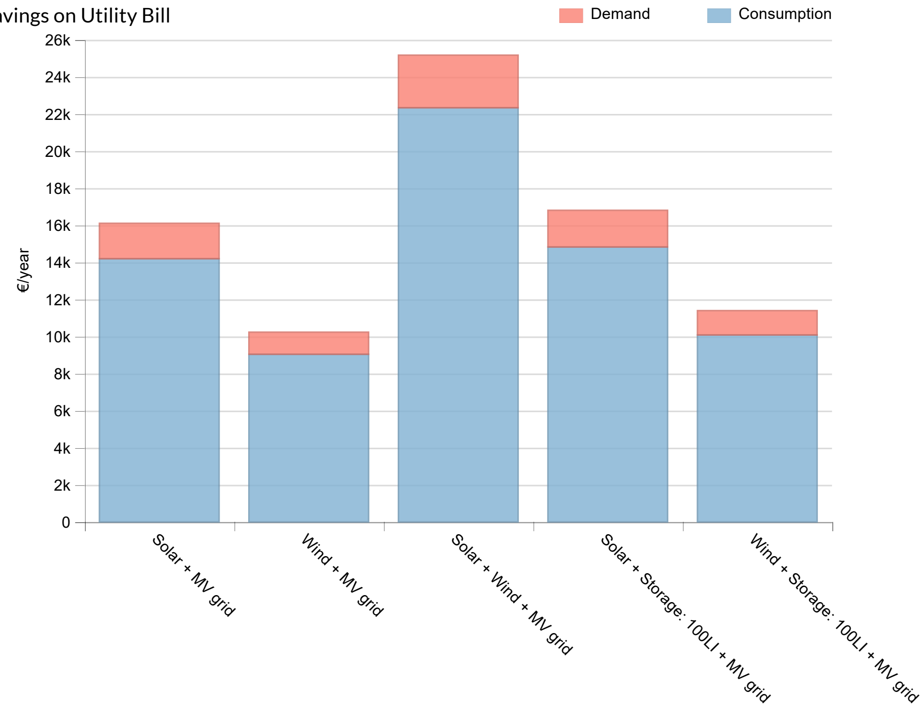


Overview of Optimized System Installation Options

This section presents a summary and comparison of some possible systems. The following sections give details on each system.

The lowest net present cost system architecture is:	Solar + MV grid
Your annual savings can be:	16.101 €
System capital cost:	282.699 €
Over the project lifetime of 20 years, your savings can be:	322.022 €
Your IRR can be:	6,6%
Your payback time can be:	11 years

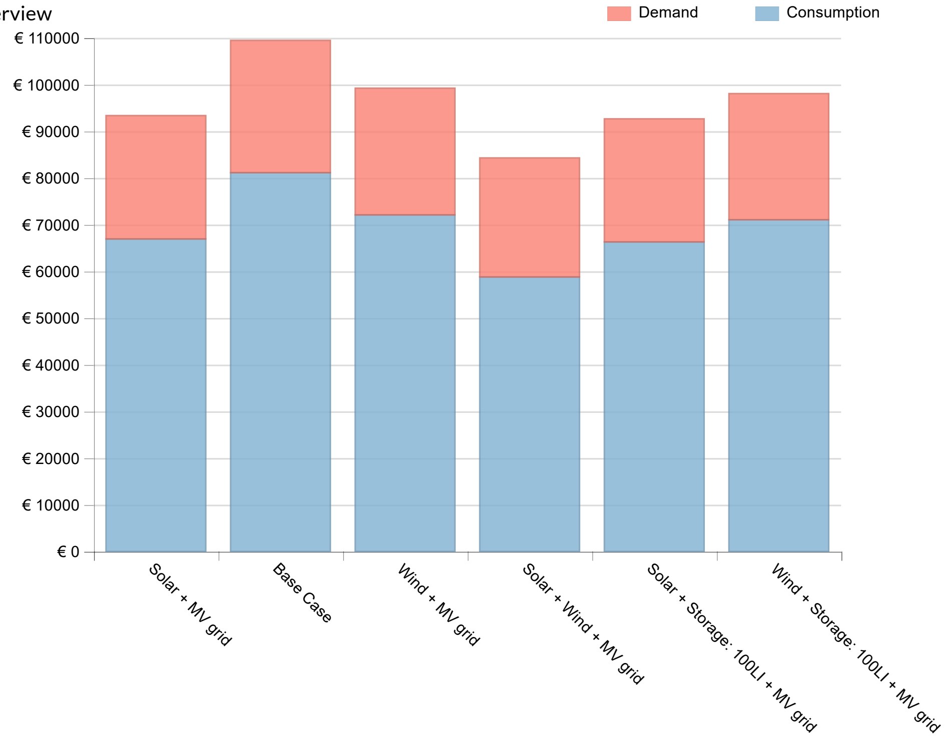
Figure 1: Projected Annual Savings on Utility Bill



	Base Case	Solar + MV grid	Wind + MV grid	Solar + Wind + MV grid	Solar + Storage: 100LI + MV grid	Wind + Storage: 100LI + MV grid
Costs and Savings						
CAPEX	120.000 €	282.699 €	219.200 €	381.899 €	332.931 €	269.432 €
OPEX	109.444 €	94.509 €	101.694 €	87.920 €	95.369 €	102.143 €
Annual Total Savings (€)	0 €	14.935 €	7.750 €	21.524 €	14.074 €	7.301 €
Annual Utility Bill Savings (€)	0 €	16.101 €	10.230 €	25.170 €	16.802 €	11.392 €

	Base Case	Solar + MV grid	Wind + MV grid	Solar + Wind + MV grid	Solar + Storage: 100LI + MV grid	Wind + Storage: 100LI + MV grid
Annual Demand Charges (€/yr)	28.324 €/yr	26.416 €/yr	27.134 €/yr	25.488 €/yr	26.348 €/yr	27.013 €/yr
Annual Energy Charges (€/yr)	81.120 €/yr	66.927 €/yr	72.080 €/yr	58.786 €/yr	66.294 €/yr	71.039 €/yr
Economic Metrics						
Discounted payback time (yrs)		19,2				
Simple payback time (yrs)		11,4	12,8	12,6	18,0	
LCOE (€/kWh)	0,102 €/kWh	0,096 €/kWh	0,098 €/kWh	0,093 €/kWh	0,101 €/kWh	0,103 €/kWh
IRR %		6,60%	4,69%	5,31%	3,01%	
Net Present Cost (€)	1.387.389 €	1.377.136 €	1.396.844 €	1.400.039 €	1.437.335 €	1.452.277 €
Environmental Impact						
CO_2 Emissions* (metric ton/yr)	742,1 t/yr	602,9 t/yr	660,4 t/yr	530,2 t/yr	598,1 t/yr	651,4 t/yr
Annual Fuel Consumption (L/yr)	n/a	n/a	n/a	n/a	n/a	n/a

Figure 2: Utility Bill Overview



Demand Charge Reduction and Calculation Introduction

HOMER Grid is a tool that can help a developer or site owner outline different options for reducing a site's electricity bill. It compares the costs and savings for installing different combinations of batteries, solar panels, and generators. HOMER Grid uses a powerful optimization to find the system that will maximize your savings.

A bill from an electric utility can be comprised of a few different types of charges. The energy charge is for the quantity of energy in kilowatt-hours (kWh) you used in total for the month. The demand charge is for the highest peak power draw in kilowatts (kW) or megawatts (MW) for the month. Finally, the fixed charge is a charge that is the same every month and is not affected by your consumption or peak demand.

HOMER Grid integrates with Genability's utility rate database, ensuring the most accurate and up-to- date results possible. HOMER Grid is the only demand charge reduction and optimization tool that considers generators as a method for peak shaving, following in HOMER's technology agnostic tradition.

The Grid tool provides an estimate. You can help ensure the accuracy of your results by checking that the baseline electricity costs listed in the report (energy and demand charges) match your actual electricity bills.

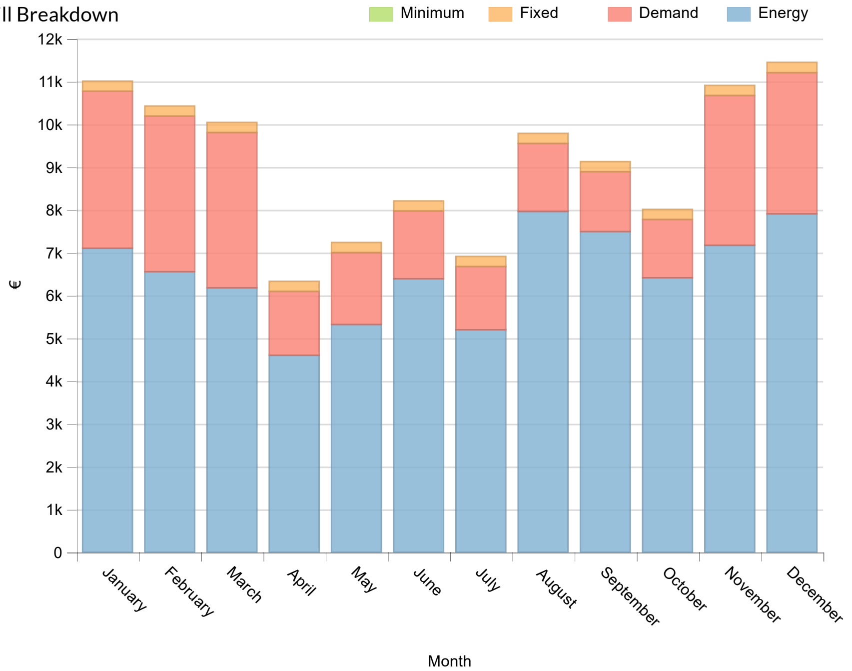
Your feedback is valuable to us. Please contact HOMER Energy with your feedback about what you'd like to see in this report and what feature requests you may have.

Base System Electric Bill

Tariff: N3-South NT

	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	7.101 €	6.554 €	6.178 €	4.601 €	5.321 €	6.390 €	5.198 €	7.961 €	7.492 €	6.412 €	7.170 €	7.906 €
	98.457 kWh	95.000 kWh	98.902 kWh	92.840 kWh	101.927 kWh	96.051 kWh	99.780 kWh	105.975 kWh	97.924 kWh	96.537 kWh	94.362 kWh	96.499 kWh
	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh	0 kWh
Demand Charges and Peak Demand	3.670 €	3.635 €	3.629 €	1.493 €	1.682 €	1.583 €	1.479 €	1.590 €	1.400 €	1.362 €	3.502 €	3.299 €
	711 kW	737 kW	830 kW	775 kW	837 kW	739 kW	820 kW	861 kW	803 kW	772 kW	690 kW	758 kW
Fixed charges (€)	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	241 €
Monthly Total	11.007 €	10.425 €	10.043 €	6.330 €	7.238 €	8.209 €	6.913 €	9.787 €	9.127 €	8.010 €	10.908 €	11.446 €
Annual Total	109.444 €											

Figure 1: Monthly Electrical Bill Breakdown



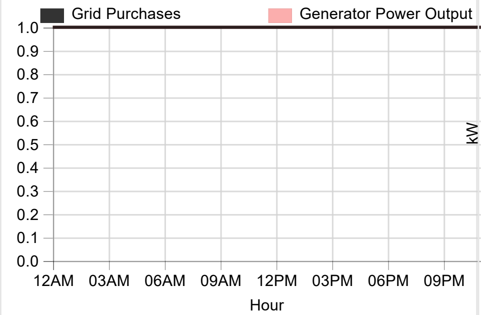
Carbon Dioxide Emissions

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	62 t	58 t	63 t	60 t	64 t	61 t	63 t	67 t	62 t	60 t	61 t	62 t
Annual Total (metric tons)	742 t/yr											

* emissions are based on an assumption of your grid's generation sources.

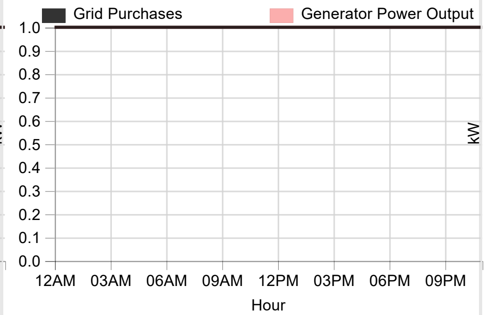
ENERO

PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES



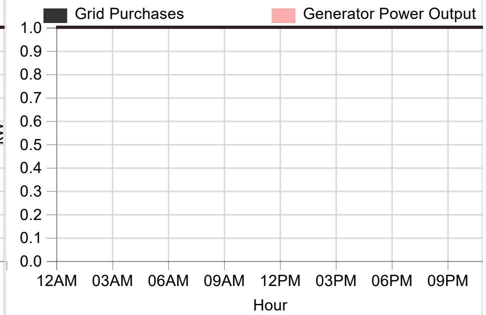
FEBRERO

PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES



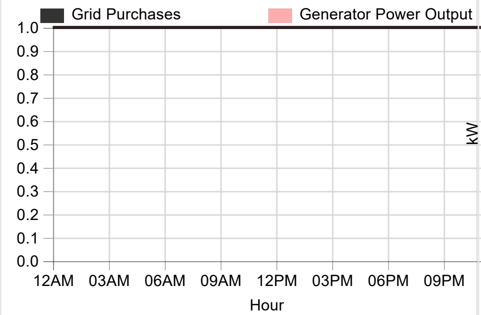
MARZO

PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES



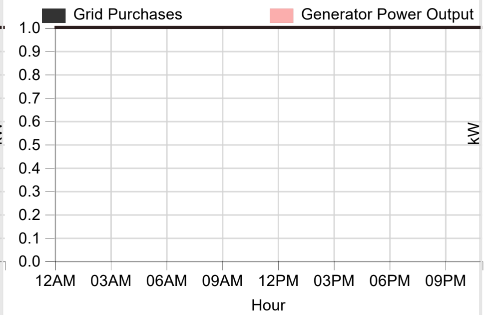
ABRIL

PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES



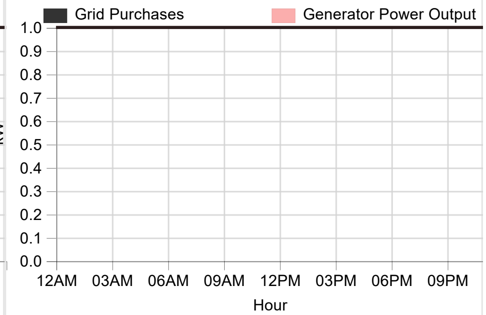
MAYO

PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES



JUNIO

PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES



JULIO

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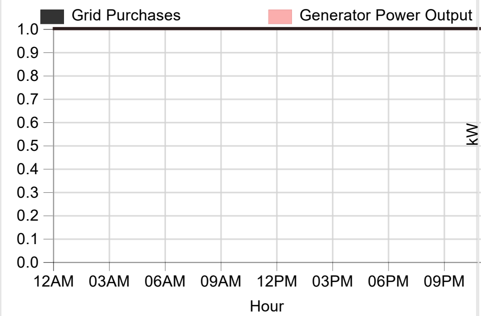
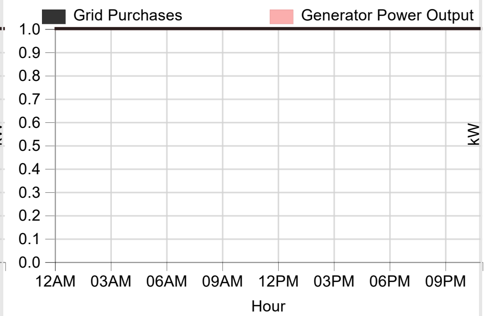


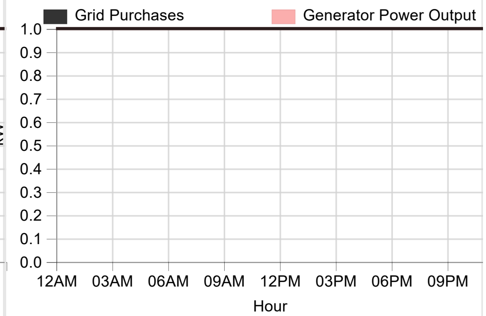
AGOSTO

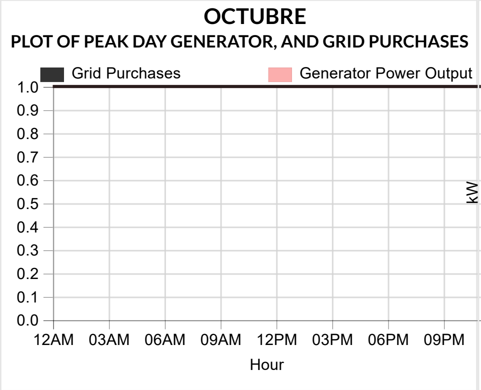
PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES



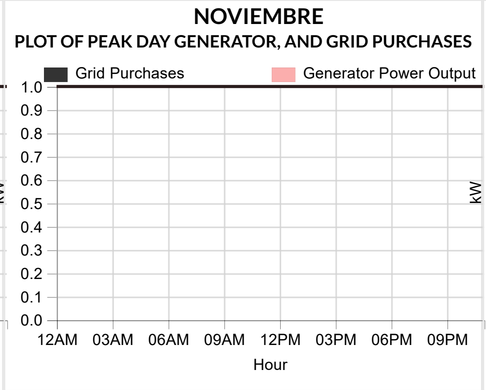
SEPTIEMBRE

PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES

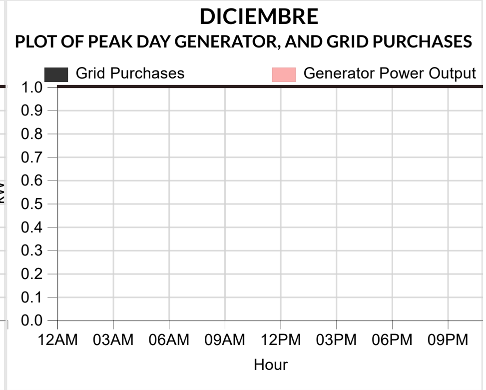




OCTUBRE
PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES
Grid Purchases
Generator Power Output
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
12AM
03AM
06AM
09AM
12PM
03PM
06PM
09PM
Hour



NOVIEMBRE
PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES
Grid Purchases
Generator Power Output
kW
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
12AM
03AM
06AM
09AM
12PM
03PM
06PM
09PM
Hour



DICIEMBRE
PLOT OF PEAK DAY GENERATOR, AND GRID PURCHASES
Grid Purchases
Generator Power Output
kW
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
12AM
03AM
06AM
09AM
12PM
03PM
06PM
09PM
Hour

System Details

System #1: Solar + MV grid

Savings Overview: Between System #1 (Solar + MV grid) and Base Case

Average annual energy bill savings:	16.101,11 €
CAPEX	282.699,00 €
Payback time (simple/discounted):	11,4/19,2 years
Internal Rate of Return (IRR)	6,60%
Project lifetime savings over 20 years:	322.022 €

Installation Recommendation: System #1

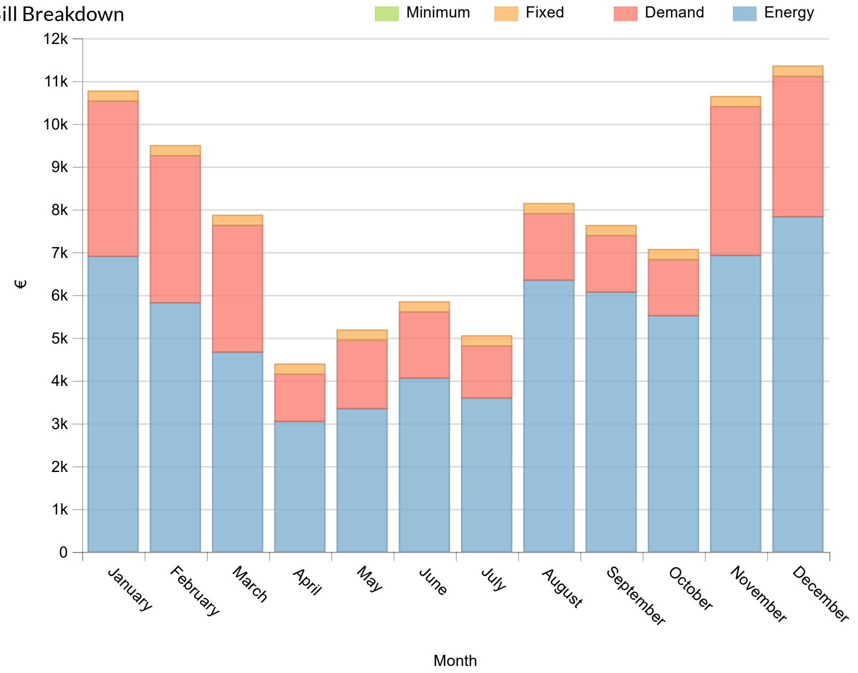
Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Solar PV plant	0,58 €/watt	281 kW	162.699 €	1.883 €/yr

Electrical Bill (Predicted): System #1

Tariff: N3-South NT

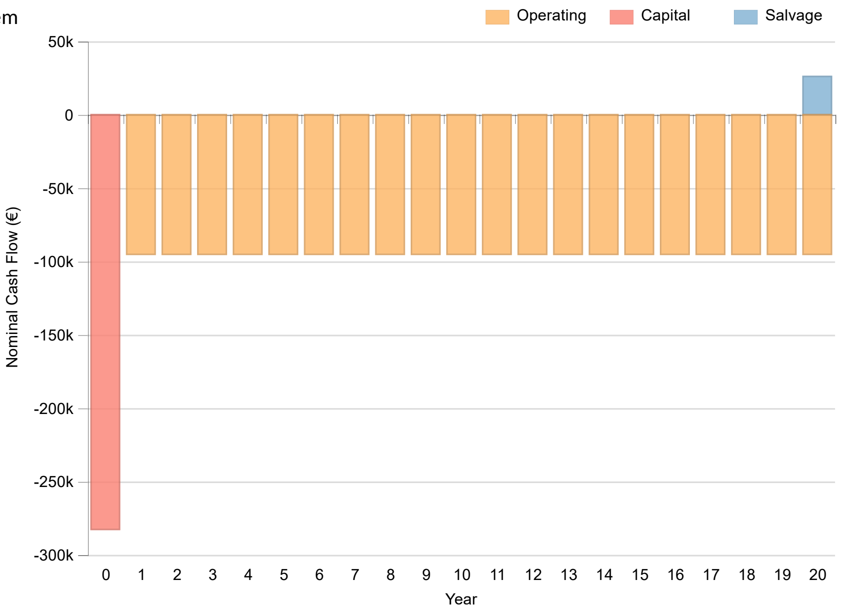
	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	6.901 €	5.816 €	4.663 €	3.044 €	3.344 €	4.057 €	3.590 €	6.345 €	6.067 €	5.514 €	6.923 €	7.828 €
	95.726 kWh	85.604 kWh	74.728 kWh	62.095 kWh	65.948 kWh	63.929 kWh	70.102 kWh	85.362 kWh	80.592 kWh	83.818 kWh	90.558 kWh	95.530 kWh
	53 kWh	1.036 kWh	4.538 kWh	8.249 kWh	10.888 kWh	9.464 kWh	6.964 kWh	14.226 kWh	2.719 kWh	1.874 kWh	408 kWh	45 kWh
Demand Charges and Peak Demand	3.626 €	3.437 €	2.960 €	1.103 €	1.600 €	1.544 €	1.216 €	1.553 €	1.318 €	1.310 €	3.474 €	3.276 €
	674 kW	730 kW	827 kW	740 kW	740 kW	726 kW	626 kW	824 kW	700 kW	772 kW	683 kW	758 kW
Fixed charges (€)	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	241 €
Monthly Total	10.762 €	9.488 €	7.859 €	4.383 €	5.179 €	5.836 €	5.042 €	8.134 €	7.621 €	7.060 €	10.633 €	11.345 €
Annual Total	93.343 €											

Figure 1: Monthly Electrical Bill Breakdown



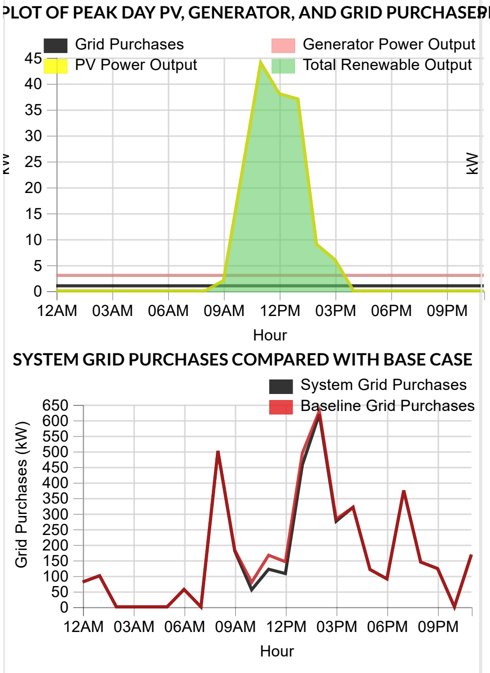
Cash Flow Summary: System #1

Figure 2: Cash Flow for System

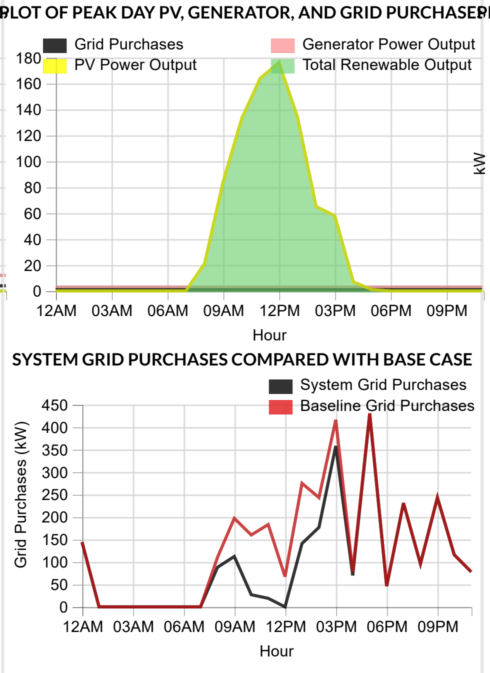


Performance Summary: System #1

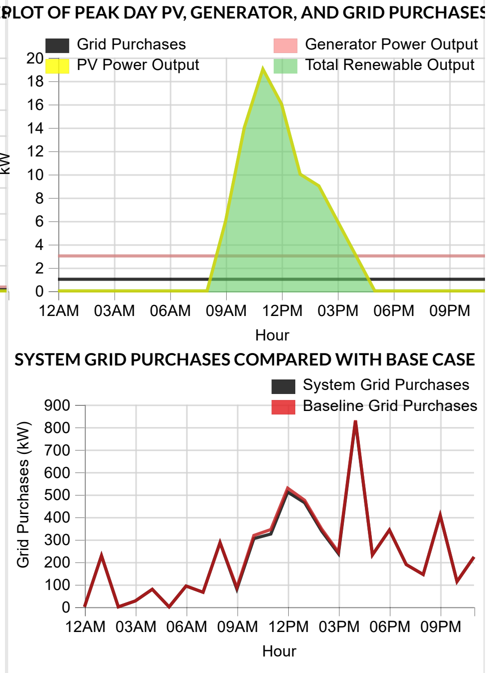
ENERO



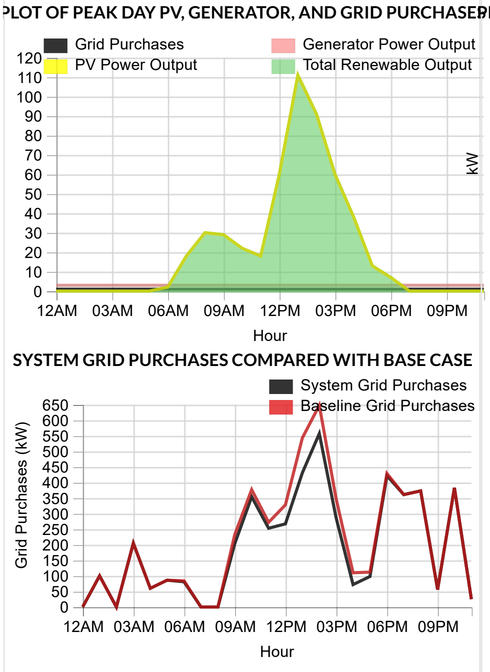
FEBRERO



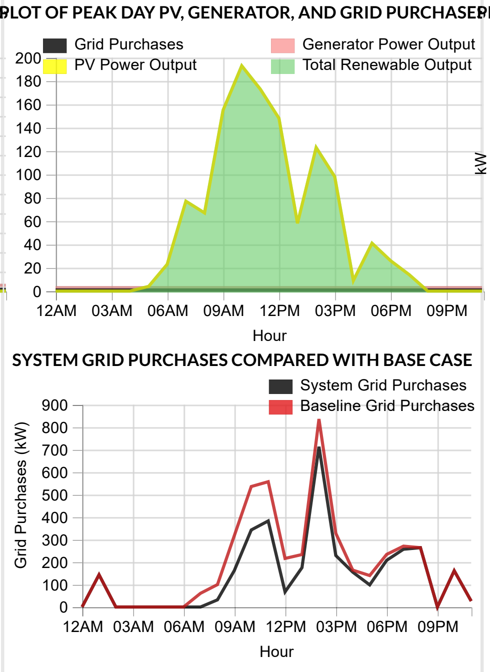
MARZO



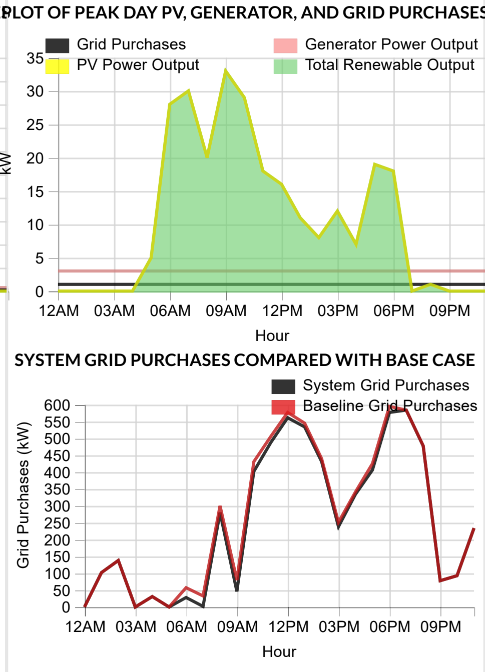
ABRIL

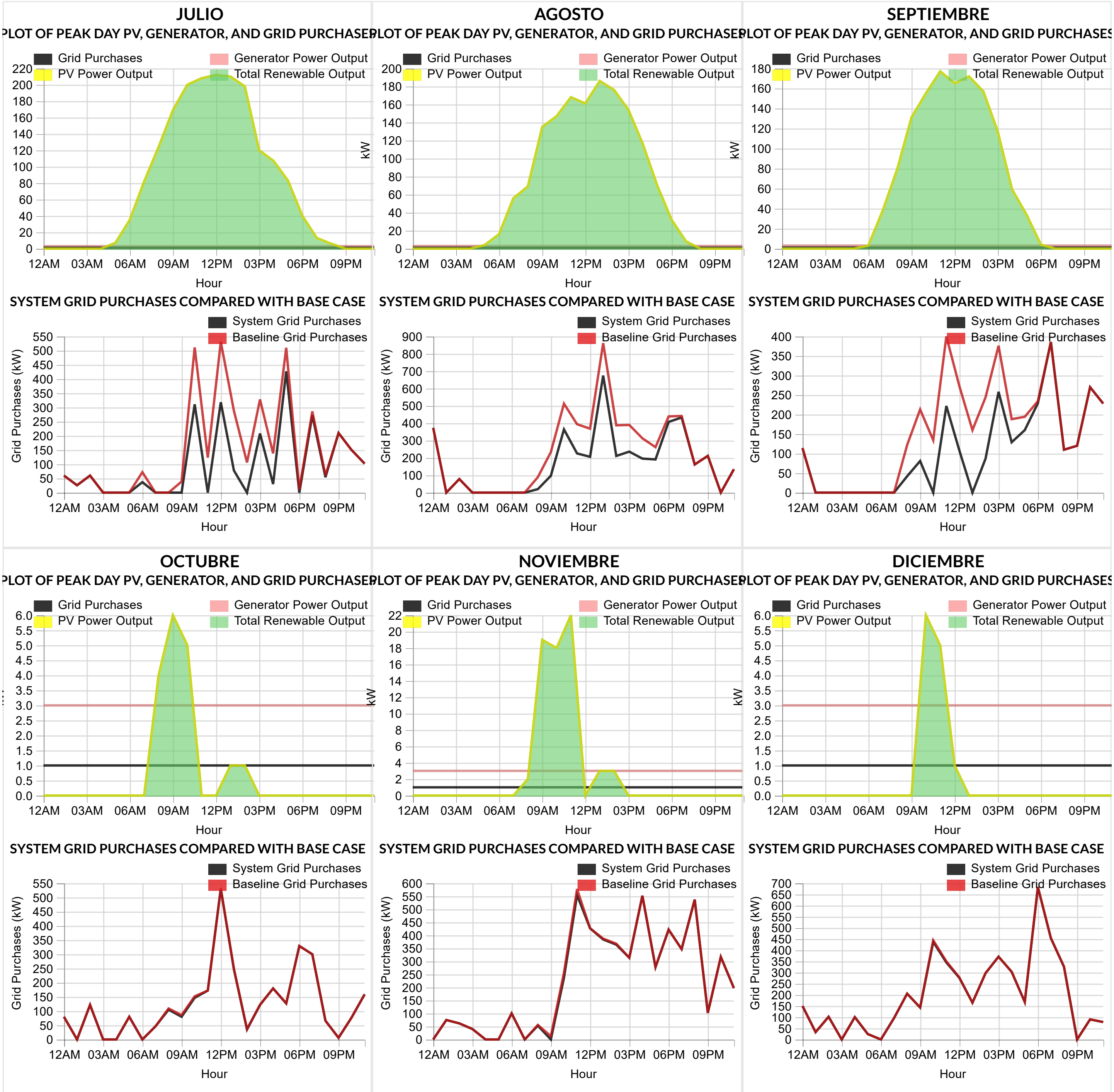


MAYO



JUNIO





Monthly Carbon Dioxide Emissions: System #1

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	60 t	52 t	48 t	40 t	42 t	40 t	44 t	54 t	51 t	52 t	58 t	62 t
Annual Total (metric tons)	603 t/yr											

* emissions are based on an assumption of your grid's generation sources.

System #2: Wind + MV grid

Savings Overview: Between System #2 (Wind + MV grid) and Base Case

Average annual energy bill savings:	10.229,89 €
CAPEX	219.200,00 €
Payback time (simple/discounted):	12,8/ years
Internal Rate of Return (IRR)	4,69%
Project lifetime savings over 20 years:	204.598 €

Installation Recommendation: System #2

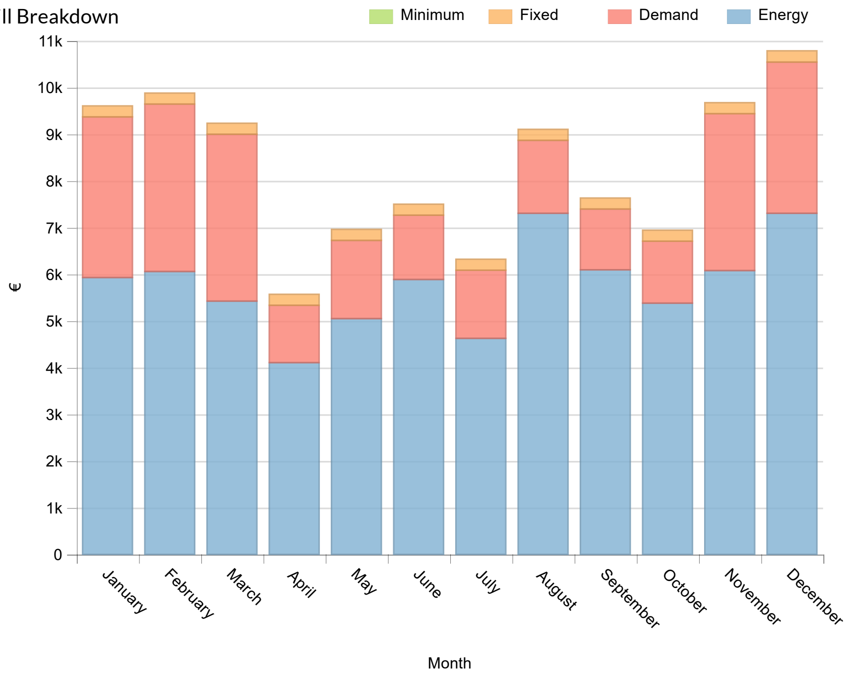
Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Wind turbines	99.200,00 €/ea	1 ea	99.200 €	2.480 €/yr

Electrical Bill (Predicted): System #2

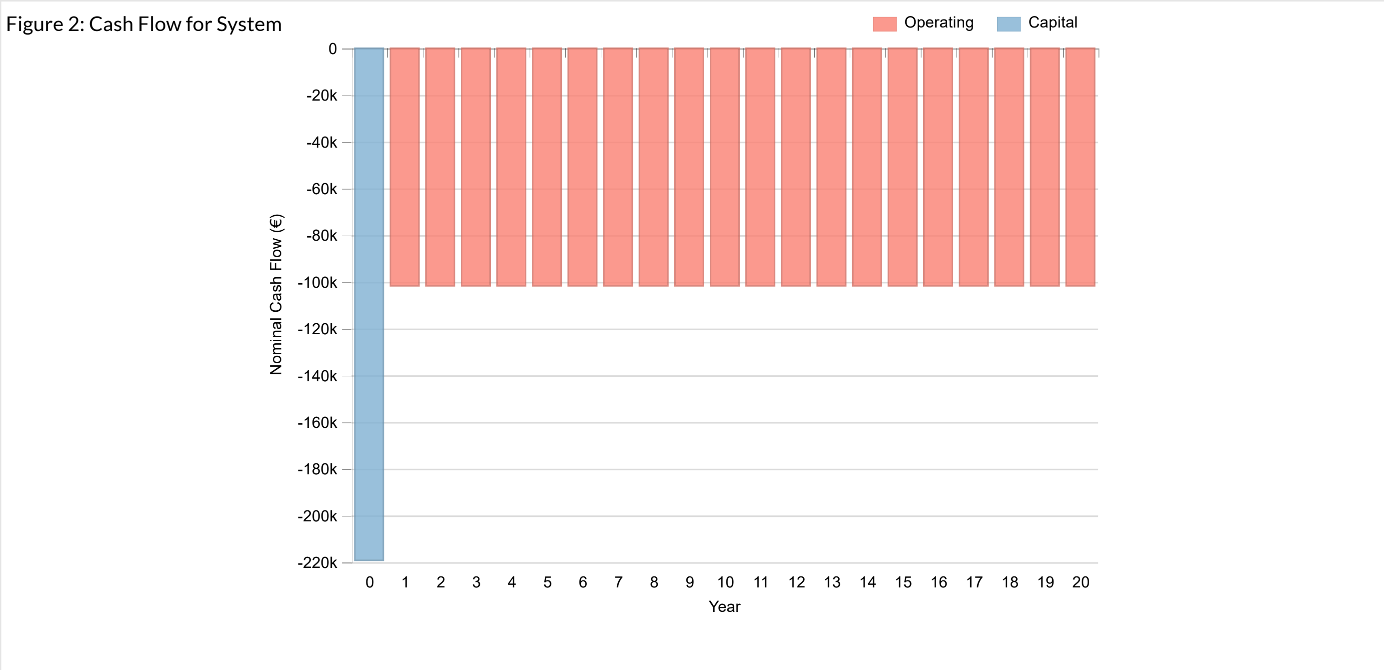
Tariff: N3-South NT

	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	5.929 €	6.058 €	5.425 €	4.106 €	5.049 €	5.887 €	4.626 €	7.305 €	6.094 €	5.380 €	6.078 €	7.306 €
	82.301 kWh	88.228 kWh	87.455 kWh	83.206 kWh	97.053 kWh	88.514 kWh	89.435 kWh	97.906 kWh	79.586 kWh	80.764 kWh	81.078 kWh	89.401 kWh
	8.152 kWh	2.657 kWh	3.914 kWh	3.222 kWh	2.427 kWh	2.274 kWh	3.701 kWh	4.611 kWh	6.562 kWh	8.033 kWh	6.491 kWh	3.726 kWh
Demand Charges and Peak Demand	3.440 €	3.587 €	3.574 €	1.229 €	1.676 €	1.378 €	1.460 €	1.562 €	1.302 €	1.327 €	3.361 €	3.238 €
	680 kW	735 kW	819 kW	692 kW	813 kW	723 kW	798 kW	843 kW	789 kW	726 kW	685 kW	756 kW
Fixed charges (€)	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	241 €
Monthly Total	9.605 €	9.881 €	9.235 €	5.571 €	6.961 €	7.501 €	6.322 €	9.103 €	7.632 €	6.944 €	9.675 €	10.785 €
Annual Total	99.214 €											

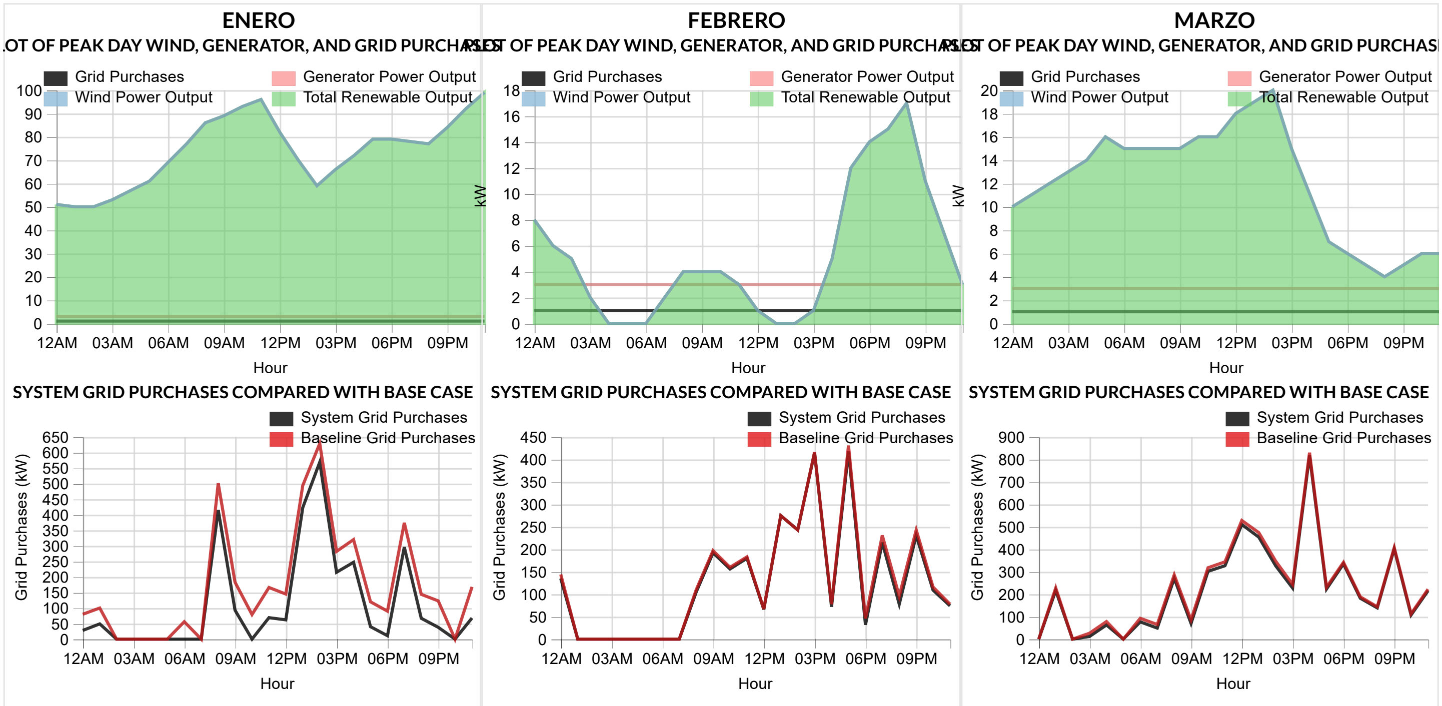
Figure 1: Monthly Electrical Bill Breakdown



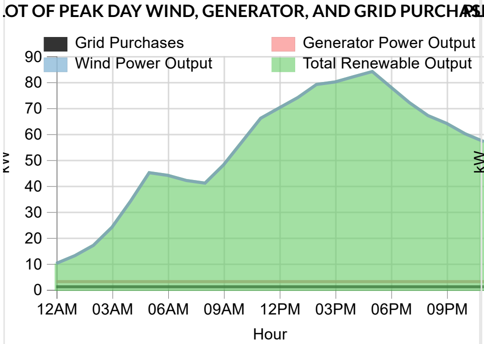
Cash Flow Summary: System #2

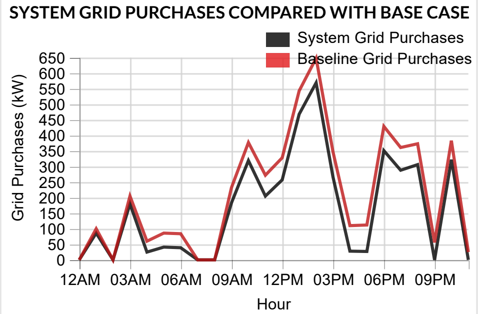


Performance Summary: System #2



ABRIL





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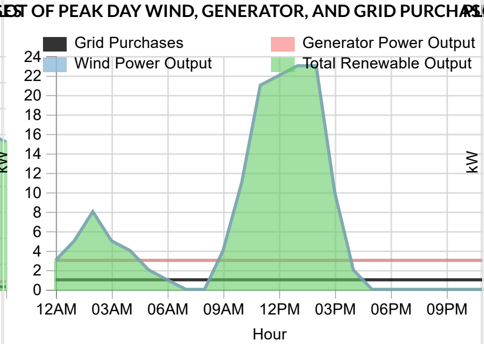

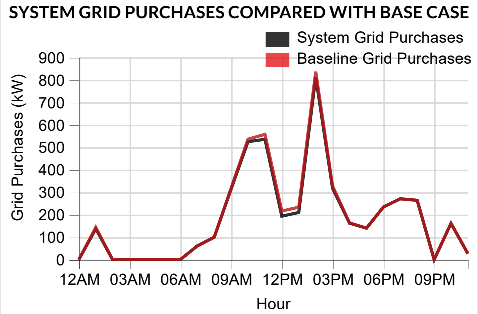

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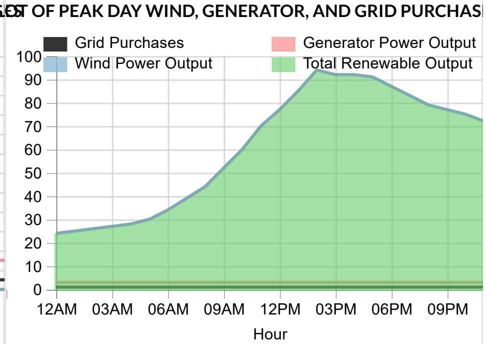
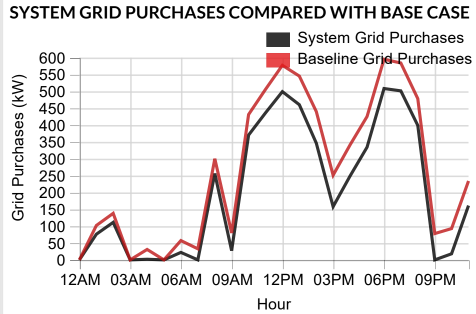
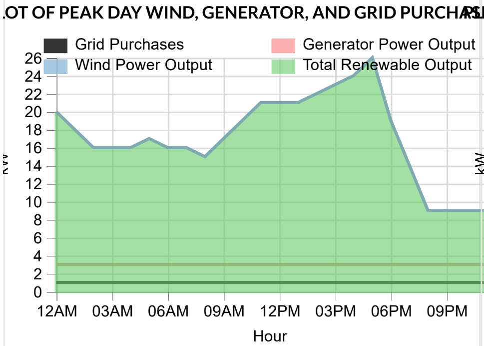
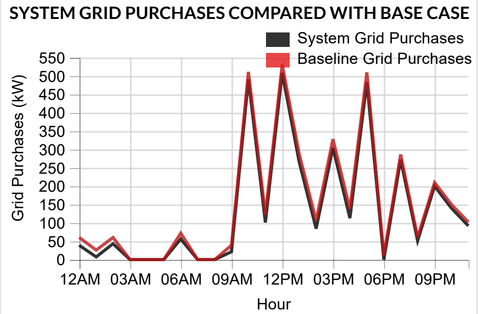


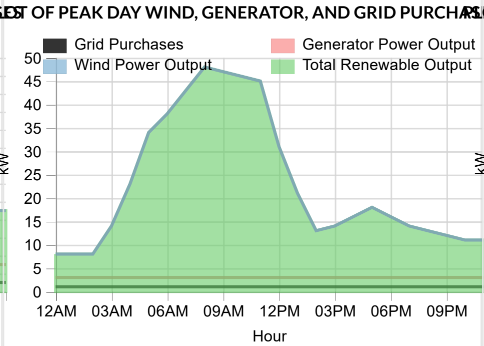


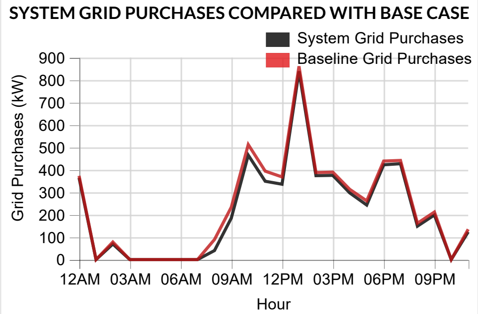
JULIO



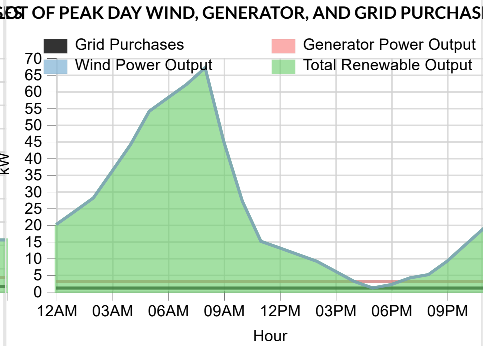


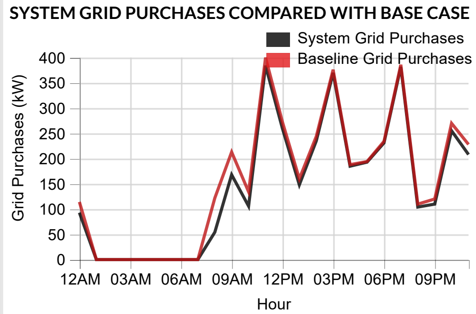
AGOSTO

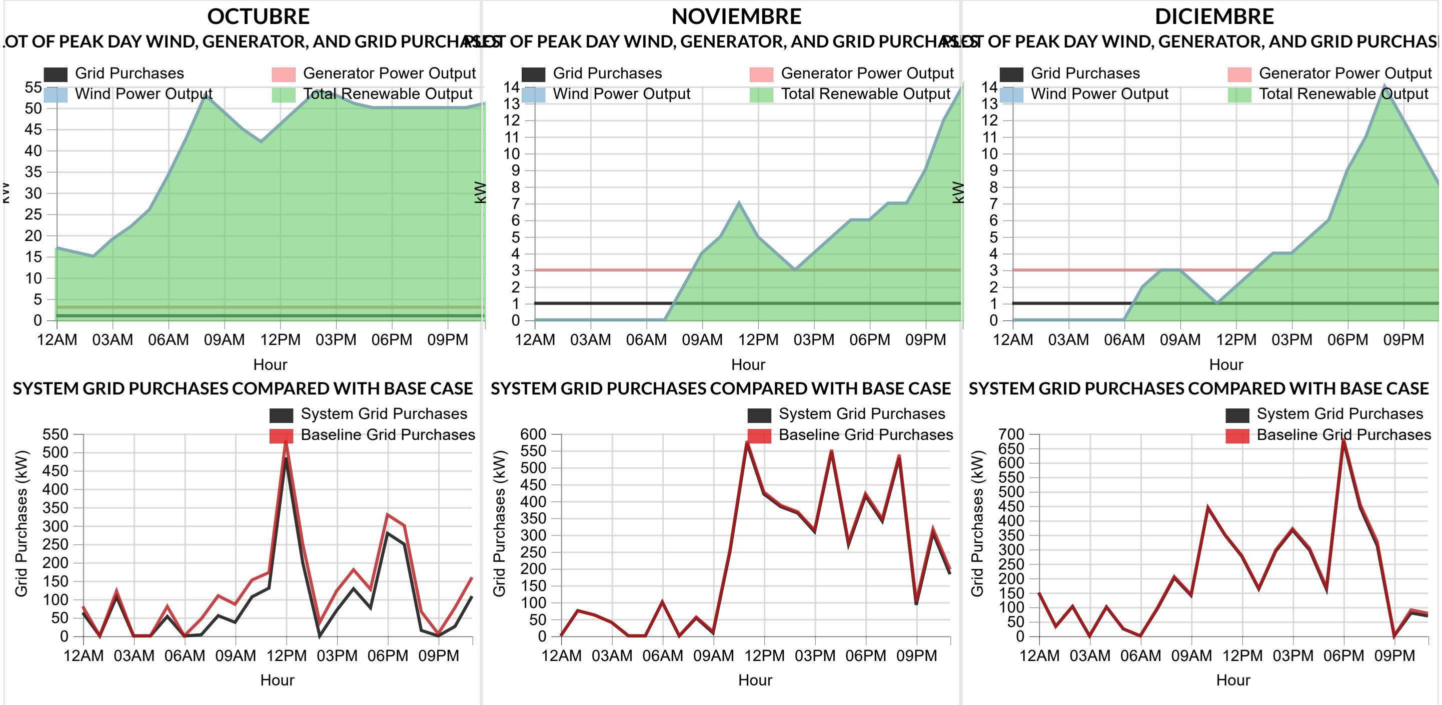




SEPTIEMBRE







Monthly Carbon Dioxide Emissions: System #2

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	52 t	54 t	55 t	54 t	61 t	56 t	57 t	62 t	50 t	51 t	52 t	58 t
Annual Total (metric tons)	660 t/yr											

* emissions are based on an assumption of your grid's generation sources.

System #3: Solar + Wind + MV grid

Savings Overview: Between System #3 (Solar + Wind + MV grid) and Base Case

Average annual energy bill savings:	25.169,62 €
CAPEX	381.899,00 €
Payback time (simple/discounted):	12,6/ years
Internal Rate of Return (IRR)	5,31%
Project lifetime savings over 20 years:	503.392 €

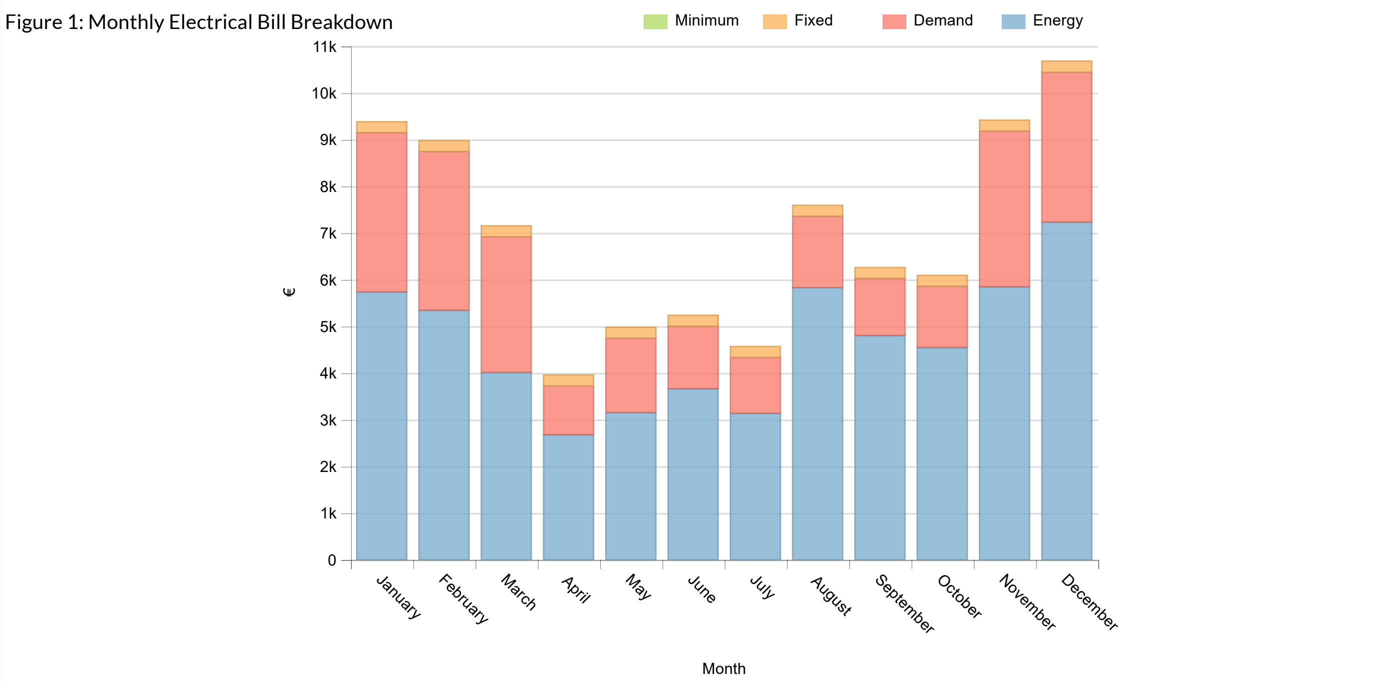
Installation Recommendation: System #3

Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Solar PV plant	0,58 €/watt	281 kW	162.699 €	1.883 €/yr
Wind turbines	99.200,00 €/ea	1 ea	99.200 €	2.480 €/yr

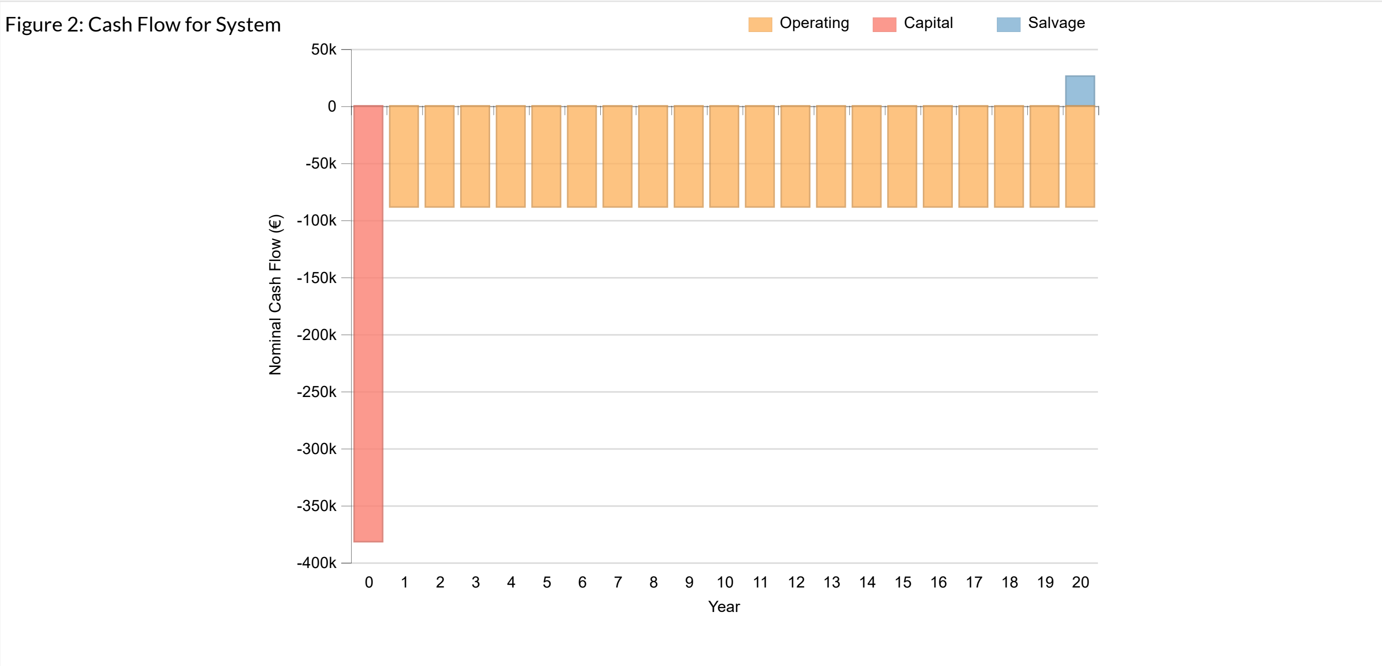
Electrical Bill (Predicted): System #3

Tariff: N3-South NT

	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	5.736 €	5.340 €	4.009 €	2.675 €	3.149 €	3.660 €	3.134 €	5.828 €	4.802 €	4.545 €	5.844 €	7.229 €
	79.672 kWh	79.126 kWh	65.090 kWh	55.035 kWh	62.457 kWh	57.902 kWh	61.909 kWh	78.875 kWh	63.859 kWh	69.026 kWh	77.469 kWh	88.454 kWh
	8.306 kWh	3.986 kWh	10.262 kWh	14.045 kWh	14.698 kWh	13.248 kWh	12.817 kWh	20.418 kWh	10.887 kWh	10.889 kWh	7.095 kWh	3.793 kWh
Demand Charges and Peak Demand	3.408 €	3.400 €	2.906 €	1.045 €	1.593 €	1.338 €	1.197 €	1.527 €	1.221 €	1.310 €	3.333 €	3.210 €
	670 kW	717 kW	815 kW	657 kW	738 kW	652 kW	588 kW	810 kW	676 kW	726 kW	678 kW	756 kW
Fixed charges (€)	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	241 €
Monthly Total	9.380 €	8.976 €	7.151 €	3.956 €	4.979 €	5.235 €	4.566 €	7.590 €	6.258 €	6.091 €	9.414 €	10.679 €
Annual Total	84.274 €											

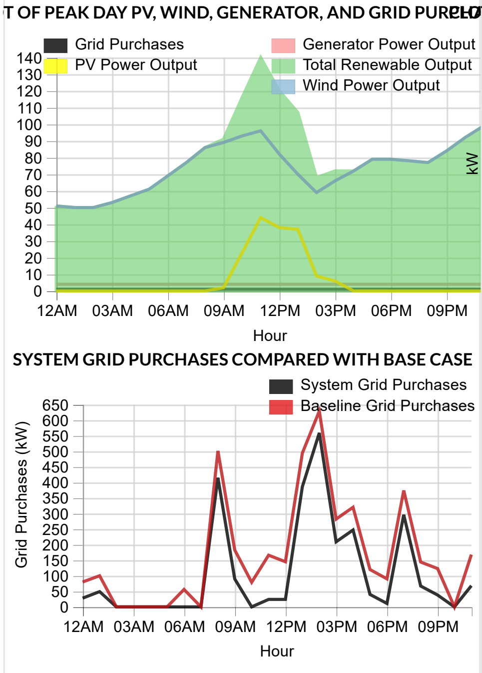


Cash Flow Summary: System #3

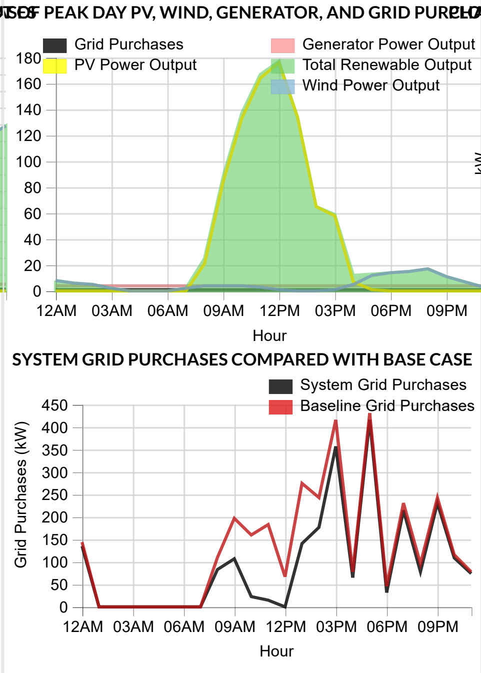


Performance Summary: System #3

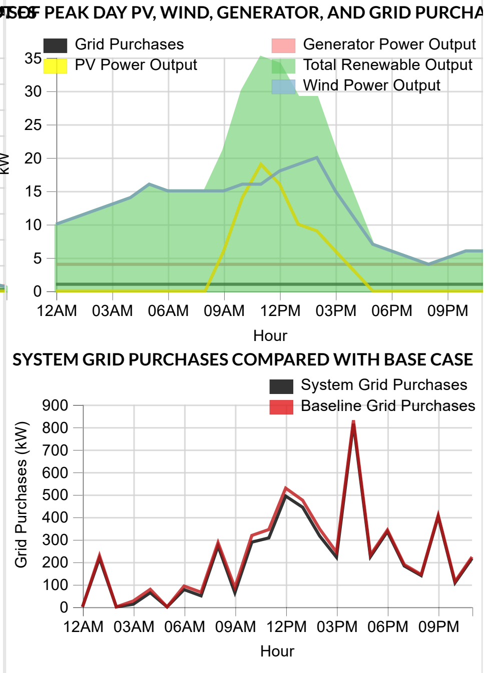
ENERO



FEBRERO



MARZO



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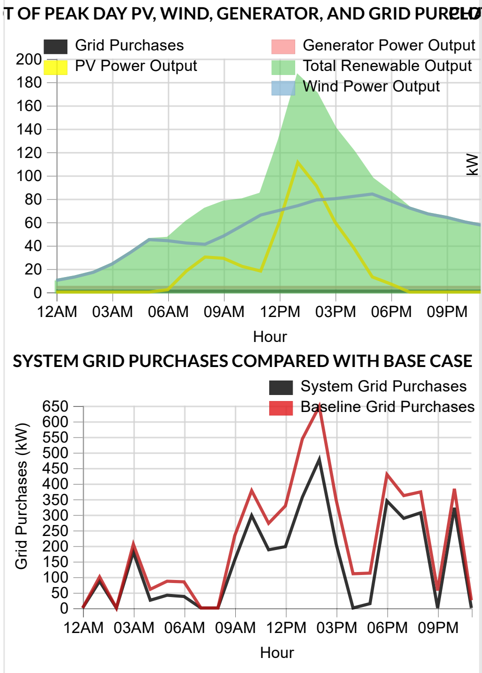
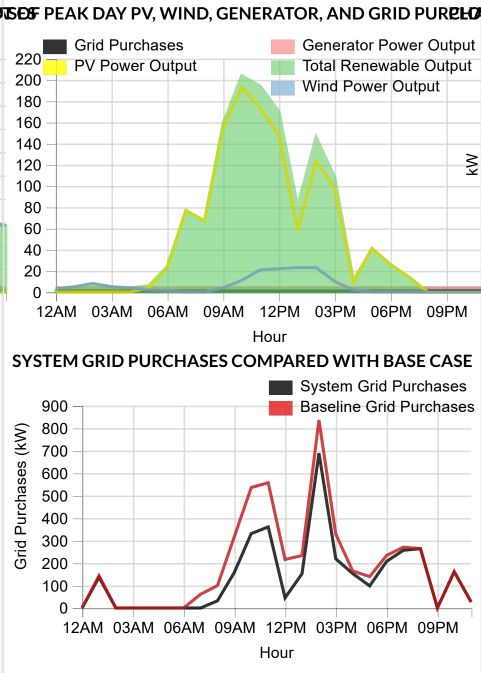


MAYO



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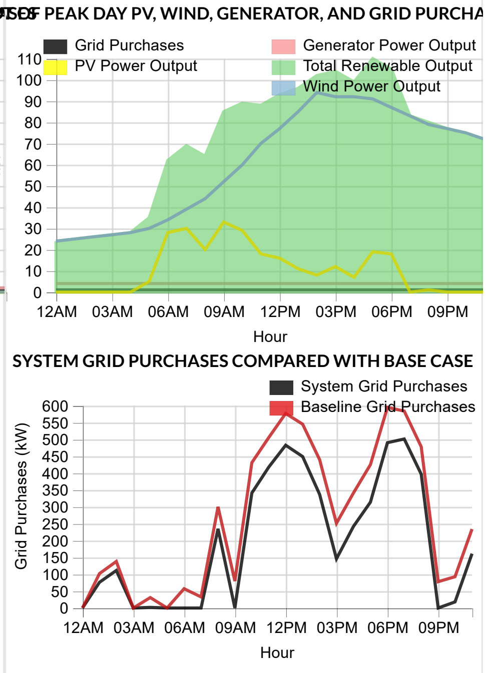

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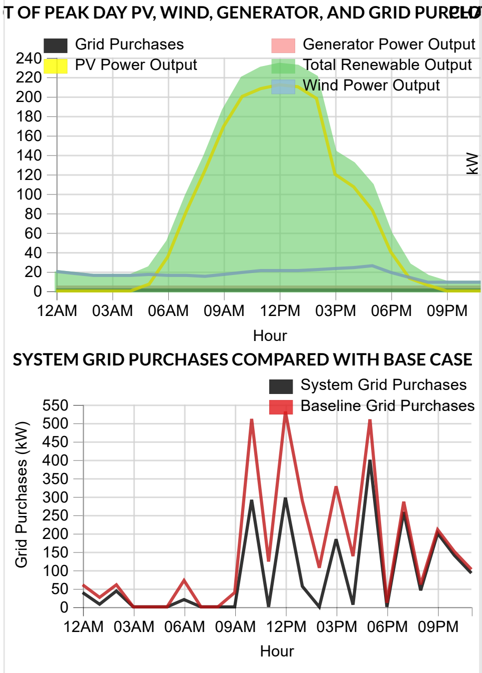
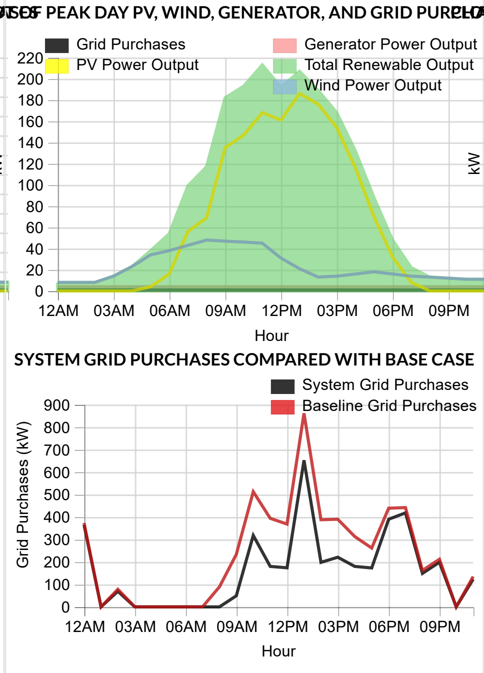
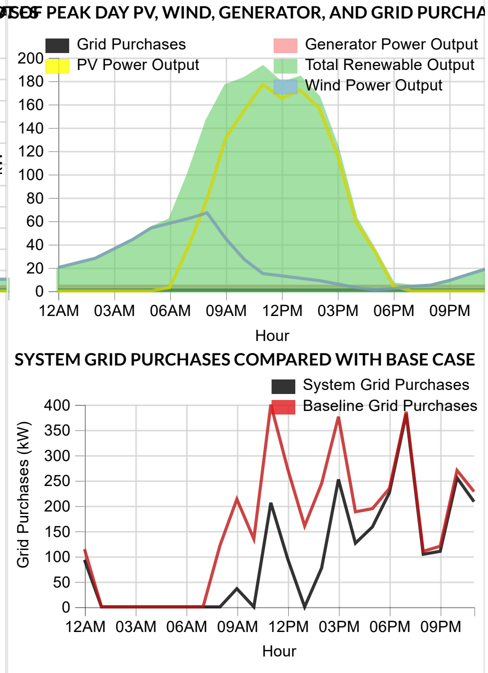


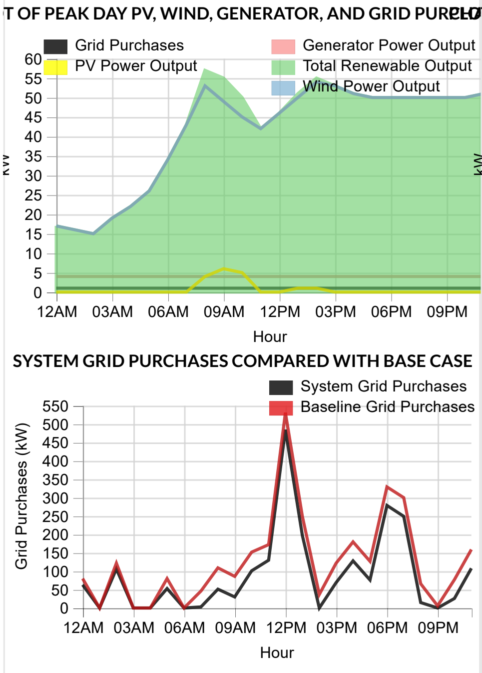
AGOSTO



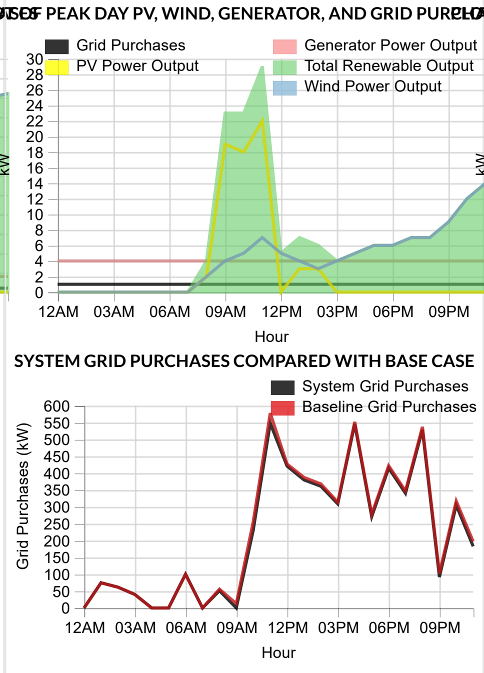
SEPTIEMBRE



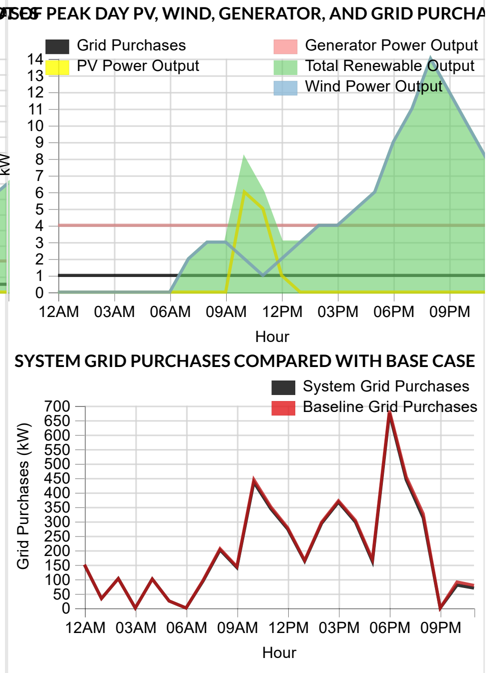
OCTUBRE



NOVIEMBRE



DICIEMBRE



Monthly Carbon Dioxide Emissions: System #3

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	50 t	48 t	42 t	35 t	40 t	36 t	39 t	49 t	40 t	43 t	50 t	57 t
Annual Total (metric tons)	530 t/yr											

* emissions are based on an assumption of your grid's generation sources.

System #4: Solar + Storage: 100LI + MV grid

Savings Overview: Between System #4 (Solar + Storage: 100LI + MV grid) and Base Case

Average annual energy bill savings:	16.802,24 €
CAPEX	332.930,60 €
Payback time (simple/discounted):	18,0/ years
Internal Rate of Return (IRR)	3,01%
Project lifetime savings over 20 years:	336.045 €

Installation Recommendation: System #4

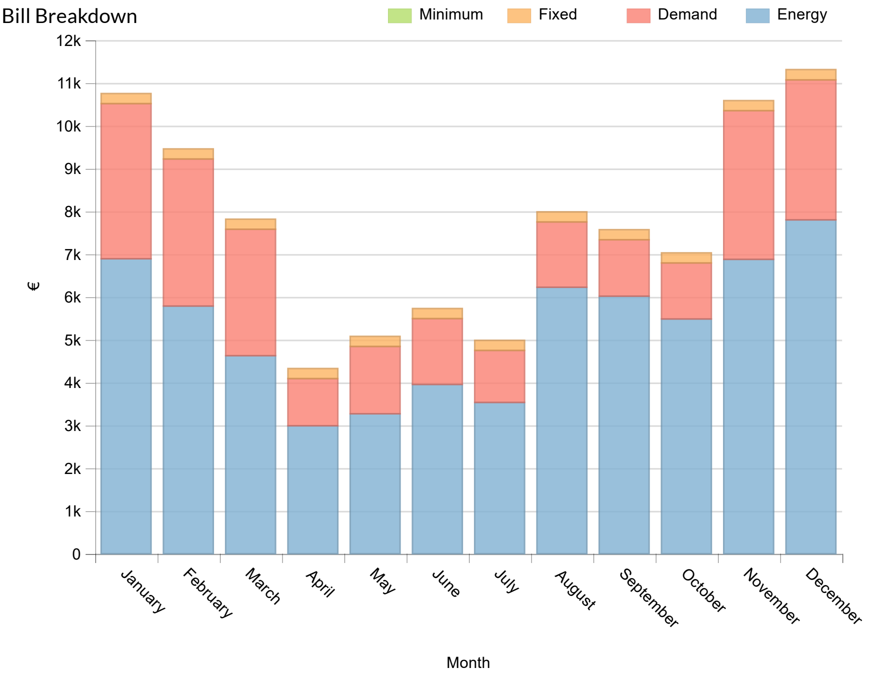
Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Solar PV plant	0,58 €/watt	281 kW	162.699 €	1.883 €/yr
Storage	49.500,00 €/ea.	1 ea.	49.500 €	827 €/yr

Electrical Bill (Predicted): System #4

Tariff: N3-South NT

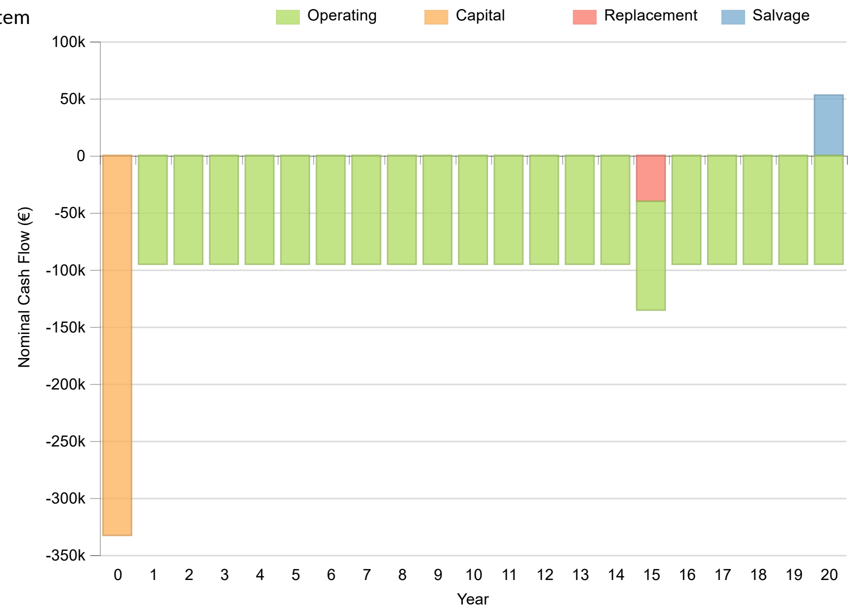
	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	6.892 €	5.787 €	4.626 €	2.990 €	3.269 €	3.954 €	3.535 €	6.225 €	6.017 €	5.485 €	6.878 €	7.800 €
	95.764 kWh	85.463 kWh	74.195 kWh	60.984 kWh	64.557 kWh	62.627 kWh	68.975 kWh	83.883 kWh	80.137 kWh	83.501 kWh	90.492 kWh	95.707 kWh
	20 kWh	825 kWh	3.772 kWh	6.879 kWh	9.168 kWh	7.829 kWh	5.574 kWh	12.407 kWh	2.100 kWh	1.454 kWh	269 kWh	12 kWh
Demand Charges and Peak Demand	3.626 €	3.437 €	2.955 €	1.103 €	1.574 €	1.539 €	1.216 €	1.527 €	1.318 €	1.310 €	3.474 €	3.270 €
	669 kW	720 kW	819 kW	740 kW	730 kW	719 kW	625 kW	814 kW	700 kW	772 kW	683 kW	750 kW
Fixed charges (€)	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	241 €
Monthly Total	10.754 €	9.459 €	7.817 €	4.328 €	5.078 €	5.730 €	4.986 €	7.988 €	7.571 €	7.031 €	10.588 €	11.312 €
Annual Total	92.642 €											

Figure 1: Monthly Electrical Bill Breakdown



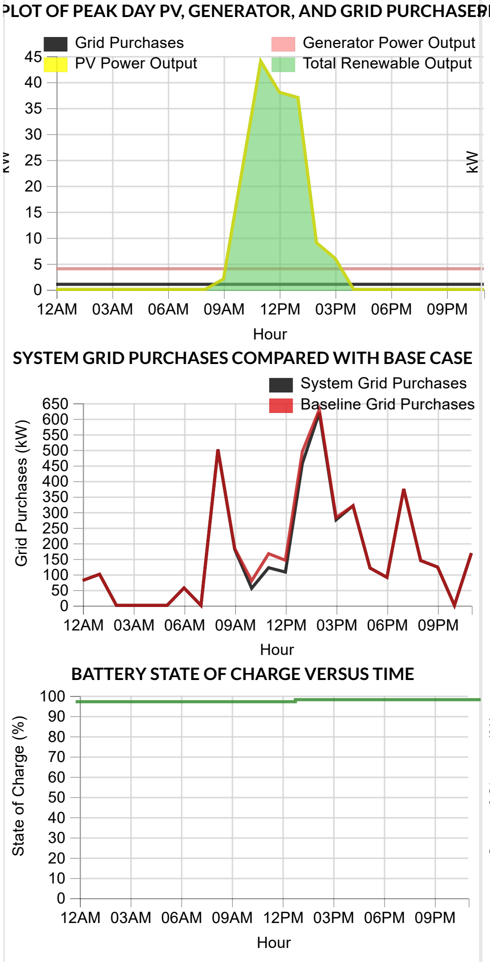
Cash Flow Summary: System #4

Figure 2: Cash Flow for System

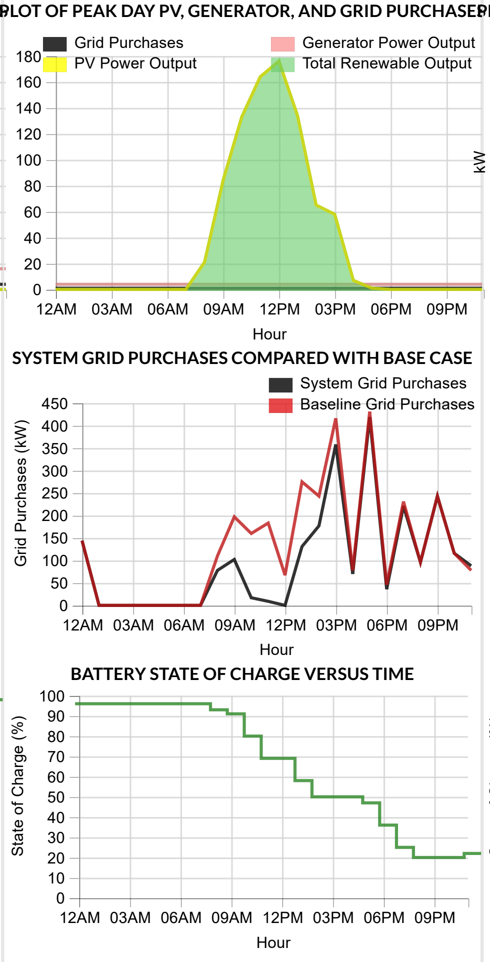


Performance Summary: System #4

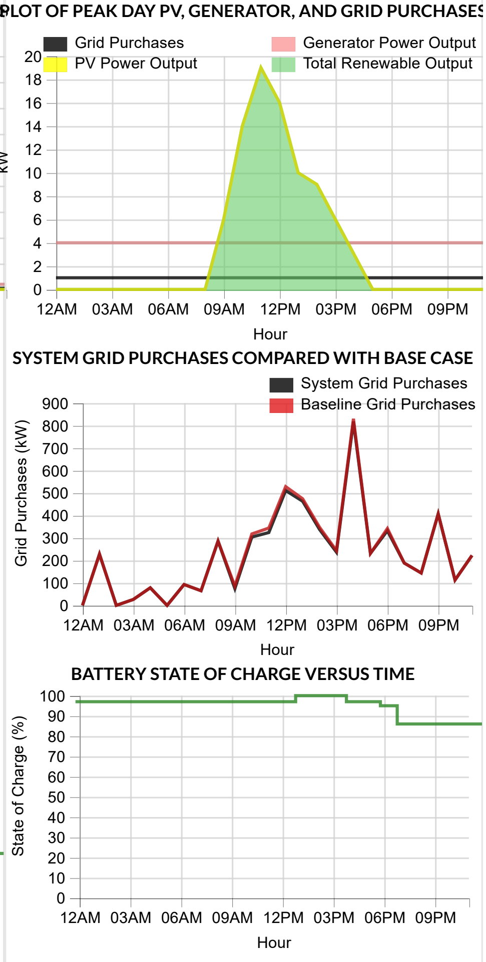
ENERO



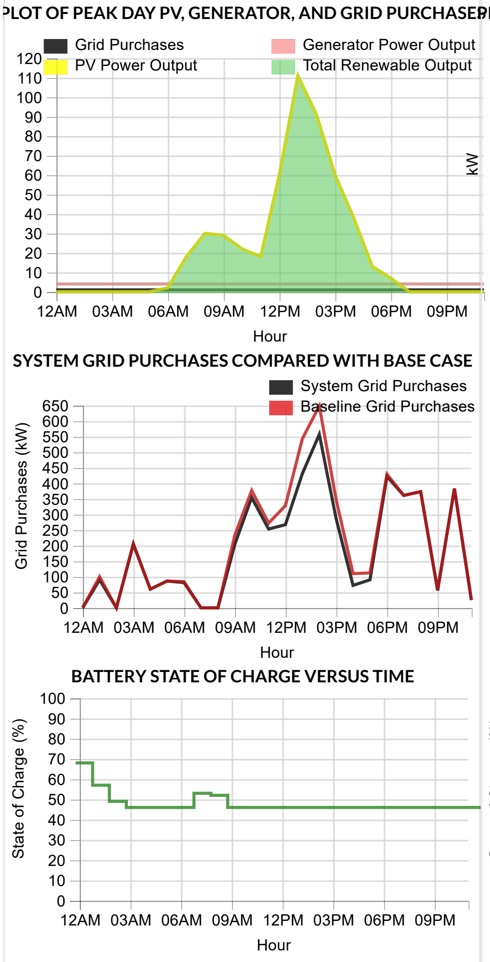
FEBRERO



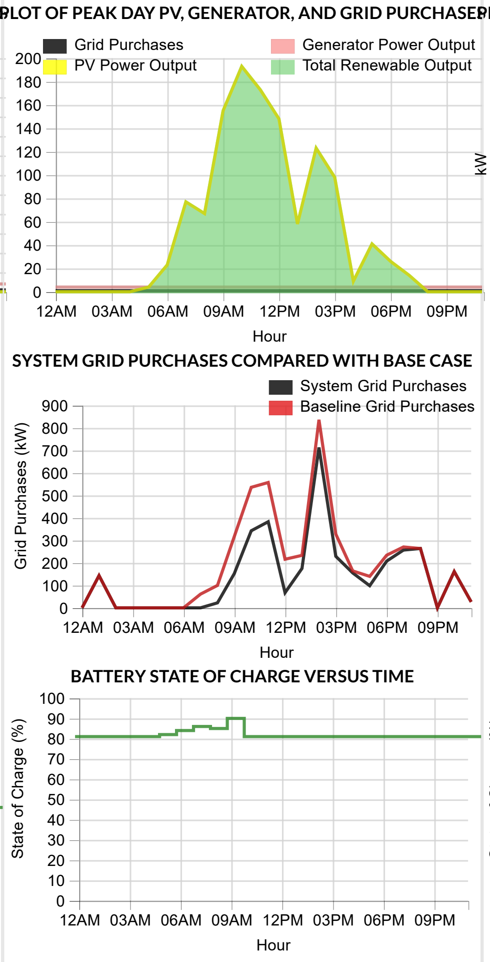
MARZO



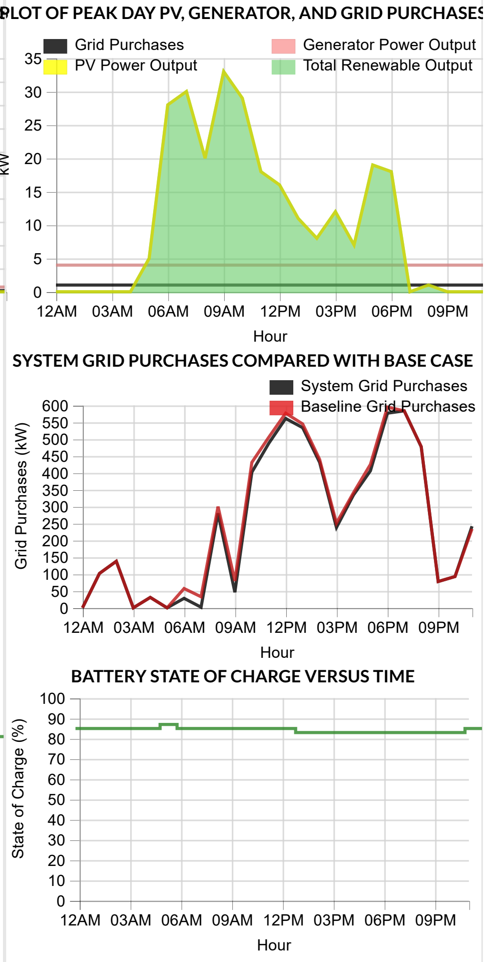
ABRIL



MAYO

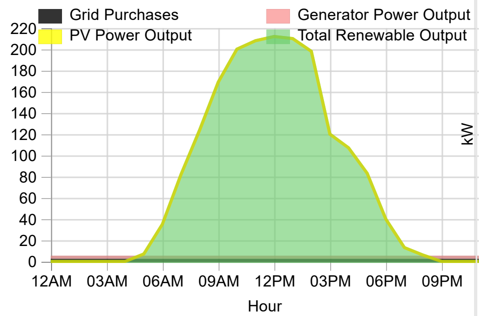


JUNIO

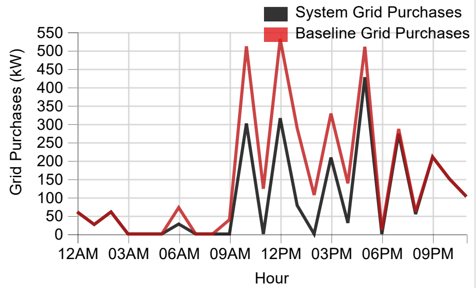


JULIO

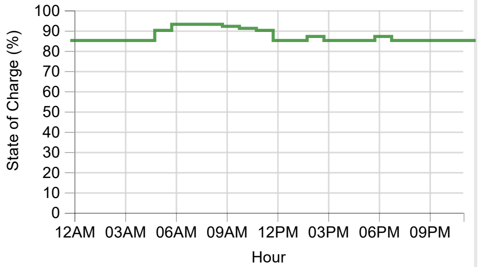
PLOT OF PEAK DAY PV, GENERATOR, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

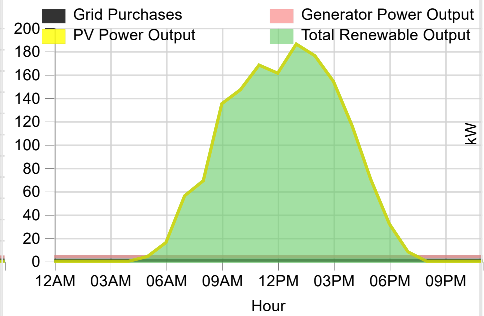


BATTERY STATE OF CHARGE VERSUS TIME

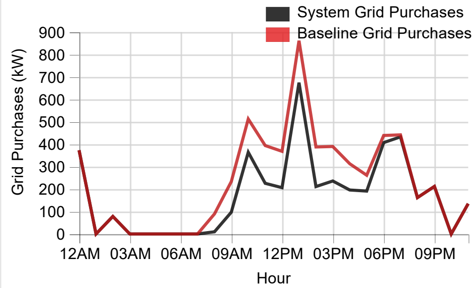


AGOSTO

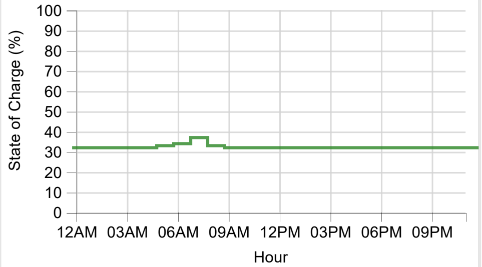
PLOT OF PEAK DAY PV, GENERATOR, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

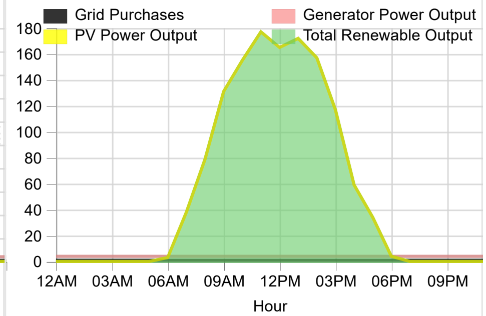


BATTERY STATE OF CHARGE VERSUS TIME

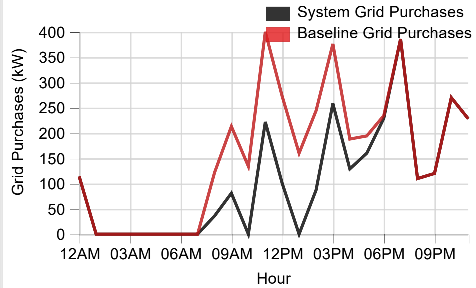


SEPTIEMBRE

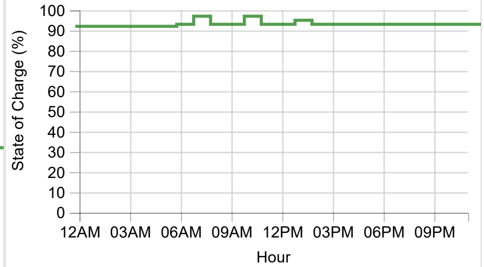
PLOT OF PEAK DAY PV, GENERATOR, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

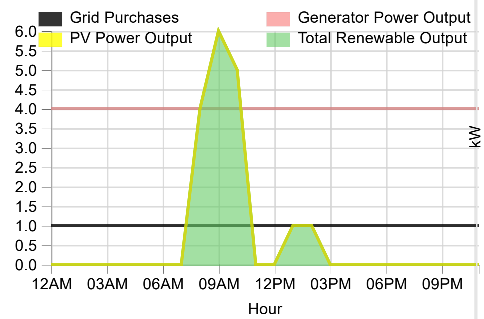


BATTERY STATE OF CHARGE VERSUS TIME

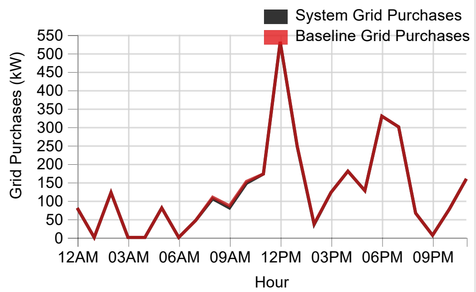


OCTUBRE

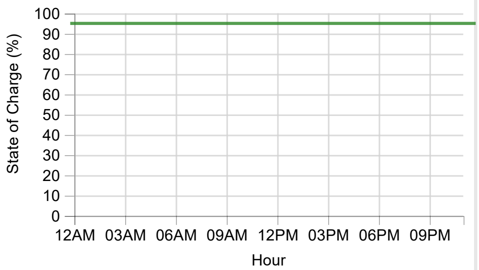
PLOT OF PEAK DAY PV, GENERATOR, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

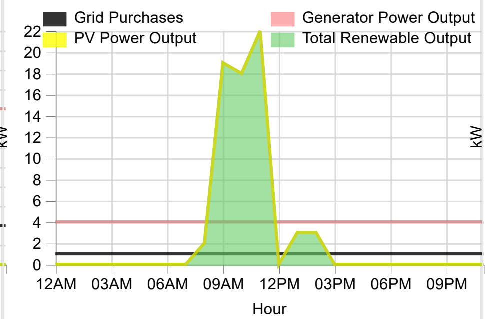


BATTERY STATE OF CHARGE VERSUS TIME

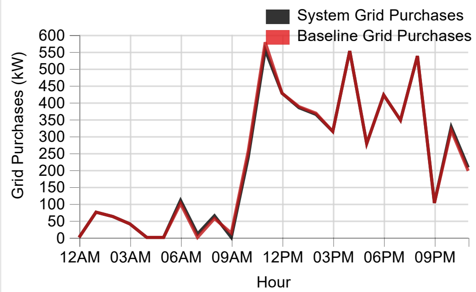


NOVIEMBRE

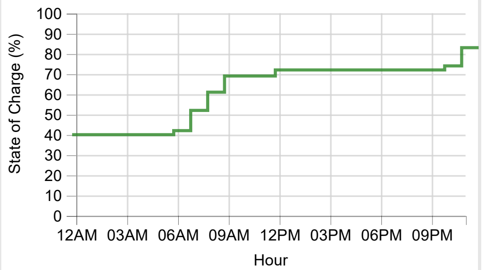
PLOT OF PEAK DAY PV, GENERATOR, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE

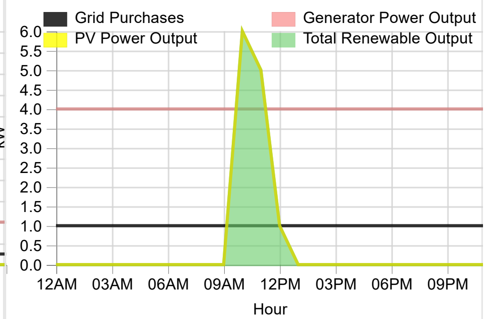


BATTERY STATE OF CHARGE VERSUS TIME

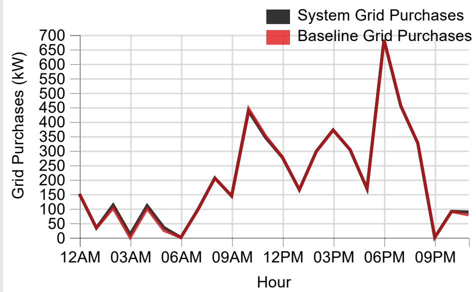


DICIEMBRE

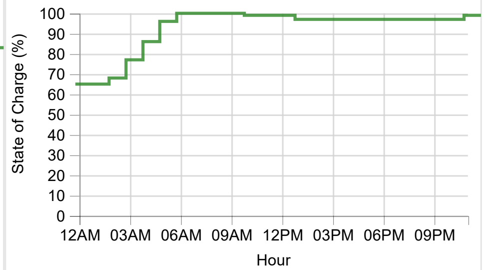
PLOT OF PEAK DAY PV, GENERATOR, AND GRID PURCHASES



SYSTEM GRID PURCHASES COMPARED WITH BASE CASE



BATTERY STATE OF CHARGE VERSUS TIME



Monthly Carbon Dioxide Emissions: System #4

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	61 t	52 t	48 t	39 t	41 t	39 t	44 t	53 t	50 t	52 t	58 t	62 t
Annual Total (metric tons)	598 t/yr											

* emissions are based on an assumption of your grid's generation sources.

System #5: Wind + Storage: 100LI + MV grid

Savings Overview: Between System #5 (Wind + Storage: 100LI + MV grid) and Base Case

Average annual energy bill savings:	11.391,96 €
CAPEX	269.431,60 €
Payback time (simple/discounted):	n/a
Internal Rate of Return (IRR)	n/a
Project lifetime savings over 20 years:	227.839 €

Installation Recommendation: System #5

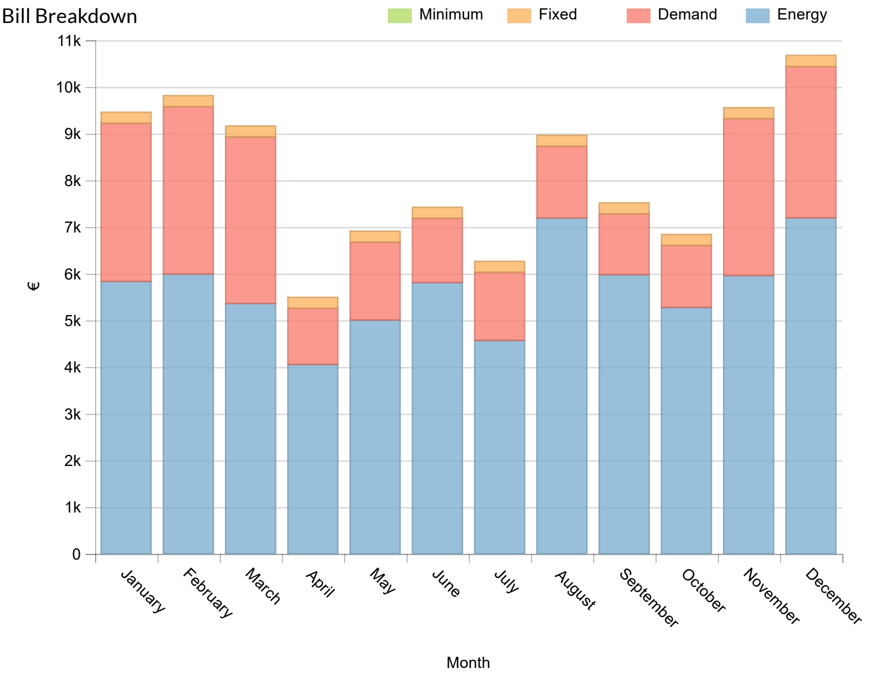
Component	Price	Installation Size	Total Installed Cost	Annual Expenses
Wind turbines	99.200,00 €/ea	1 ea	99.200 €	2.480 €/yr
Storage	49.500,00 €/ea.	1 ea.	49.500 €	827 €/yr

Electrical Bill (Predicted): System #5

Tariff: N3-South NT

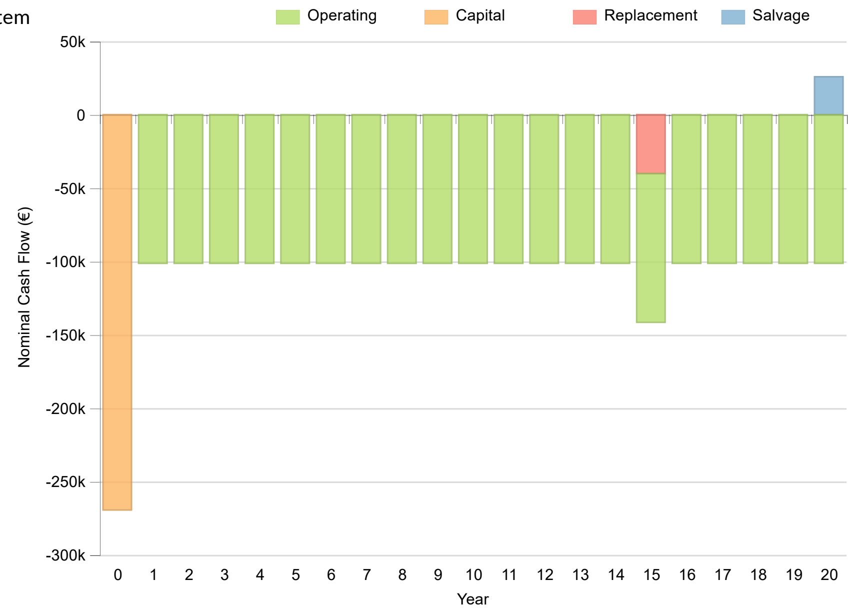
	January	February	March	April	May	June	July	August	September	October	November	December
Energy Charges, Consumption, and Sales	5.832 €	5.989 €	5.359 €	4.053 €	5.006 €	5.806 €	4.567 €	7.190 €	5.976 €	5.275 €	5.957 €	7.194 €
	80.900 kWh	87.327 kWh	86.425 kWh	82.142 kWh	96.288 kWh	87.663 kWh	88.248 kWh	96.621 kWh	78.063 kWh	79.115 kWh	79.723 kWh	88.175 kWh
	6.410 kWh	1.527 kWh	2.624 kWh	1.902 kWh	1.481 kWh	1.131 kWh	2.230 kWh	2.975 kWh	4.674 kWh	5.979 kWh	4.825 kWh	2.155 kWh
Demand Charges and Peak Demand	3.387 €	3.587 €	3.568 €	1.203 €	1.666 €	1.378 €	1.460 €	1.536 €	1.302 €	1.327 €	3.361 €	3.238 €
	680 kW	725 kW	809 kW	692 kW	813 kW	723 kW	798 kW	843 kW	779 kW	726 kW	685 kW	750 kW
Fixed charges (€)	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	236 €	241 €
Monthly Total	9.455 €	9.812 €	9.162 €	5.492 €	6.908 €	7.420 €	6.263 €	8.962 €	7.514 €	6.838 €	9.554 €	10.673 €
Annual Total	98.052 €											

Figure 1: Monthly Electrical Bill Breakdown



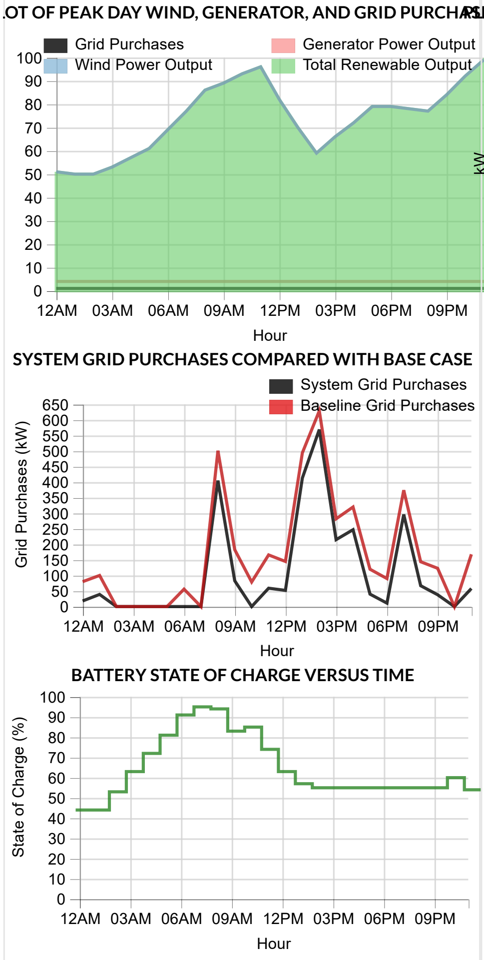
Cash Flow Summary: System #5

Figure 2: Cash Flow for System



Performance Summary: System #5

ENERO



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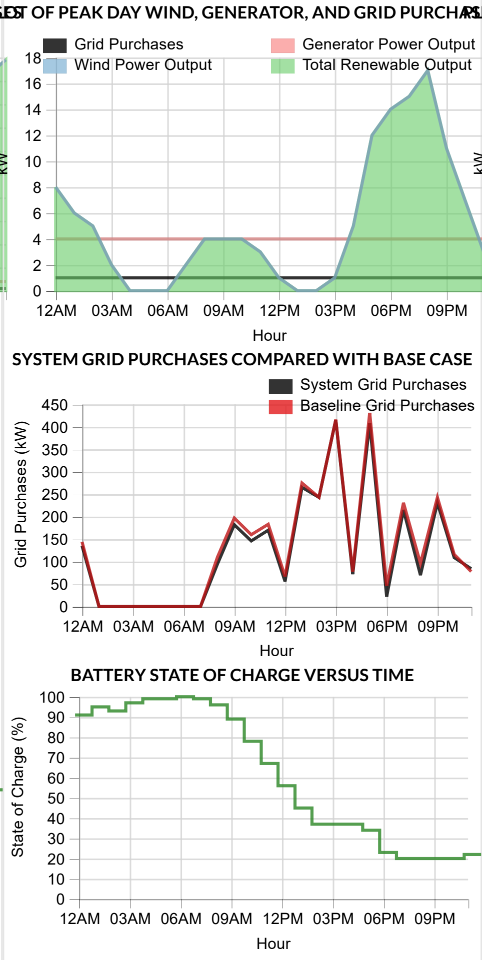
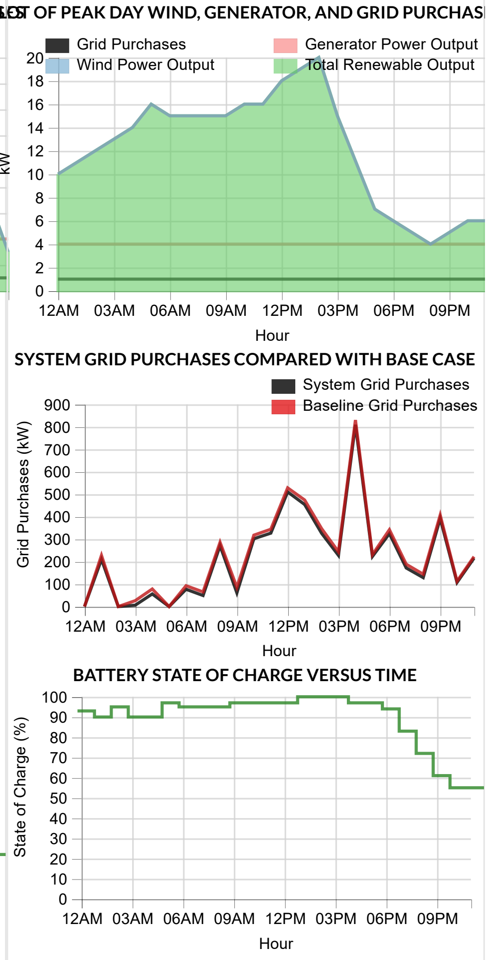
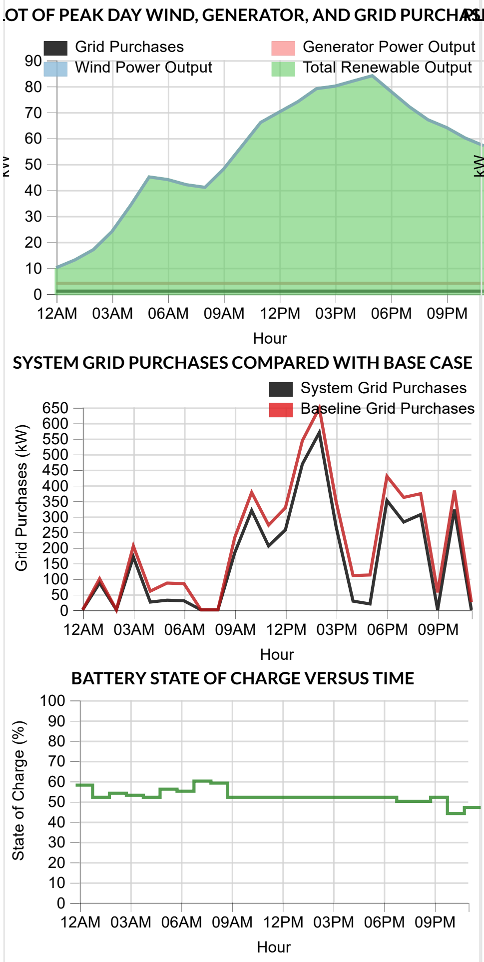


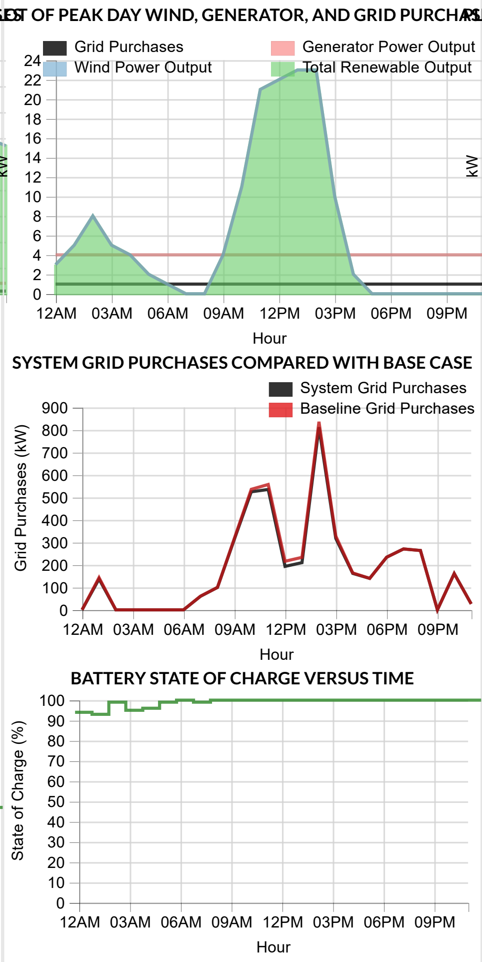
MARZO



ABRIL



MAYO



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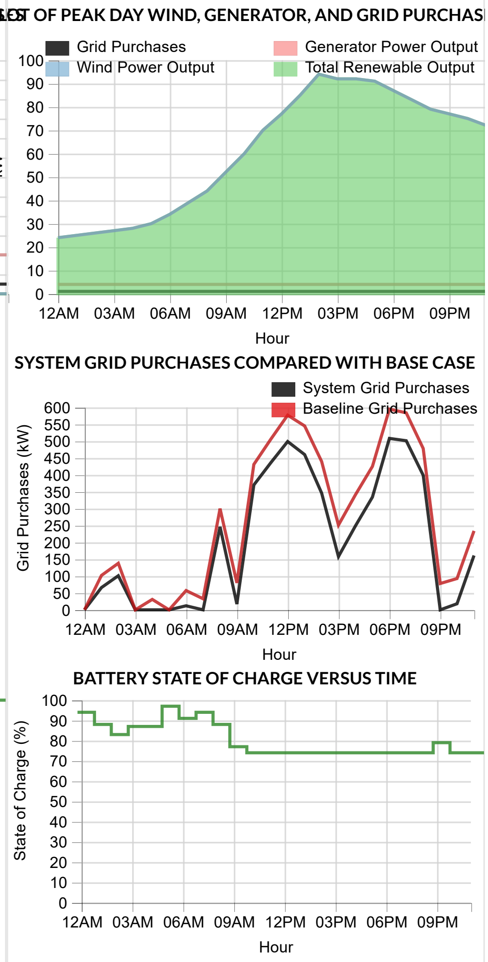

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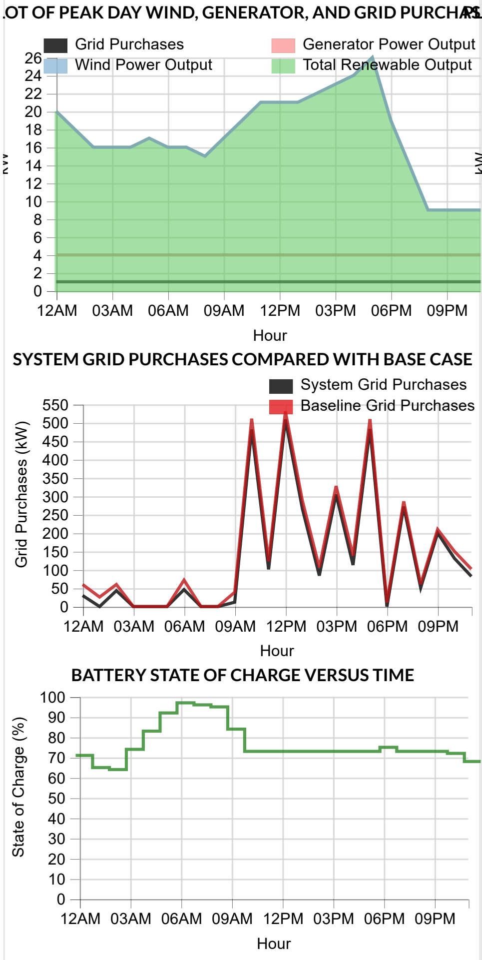
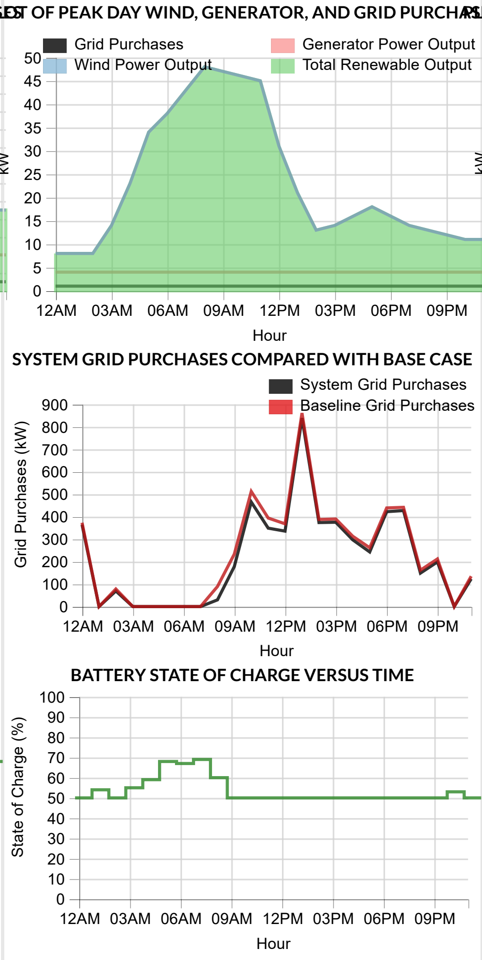
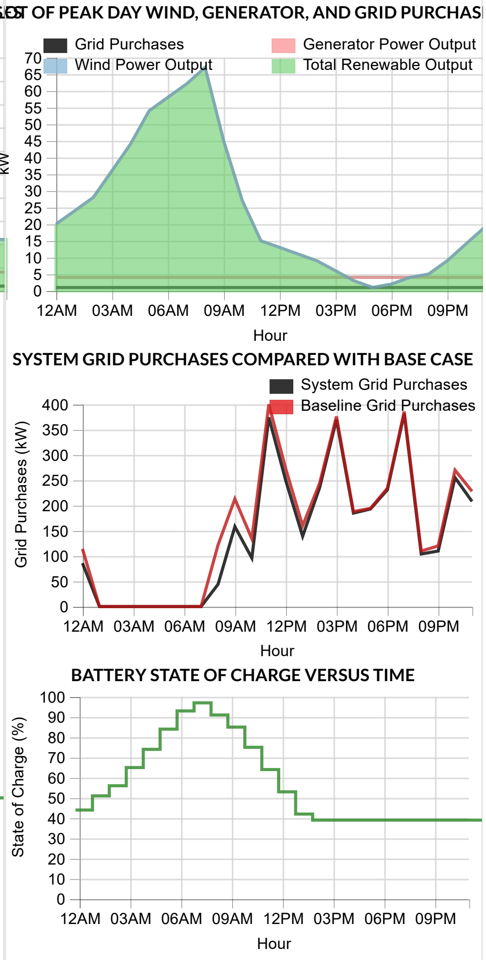


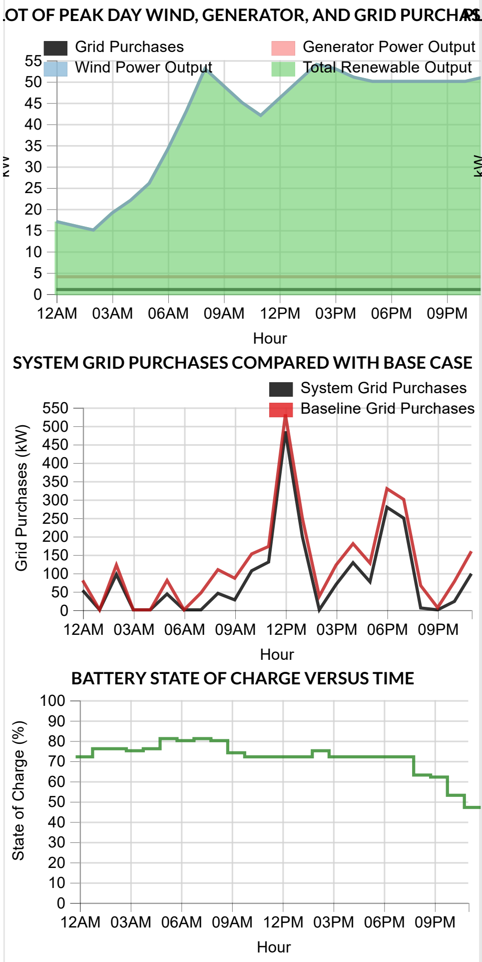
AGOSTO



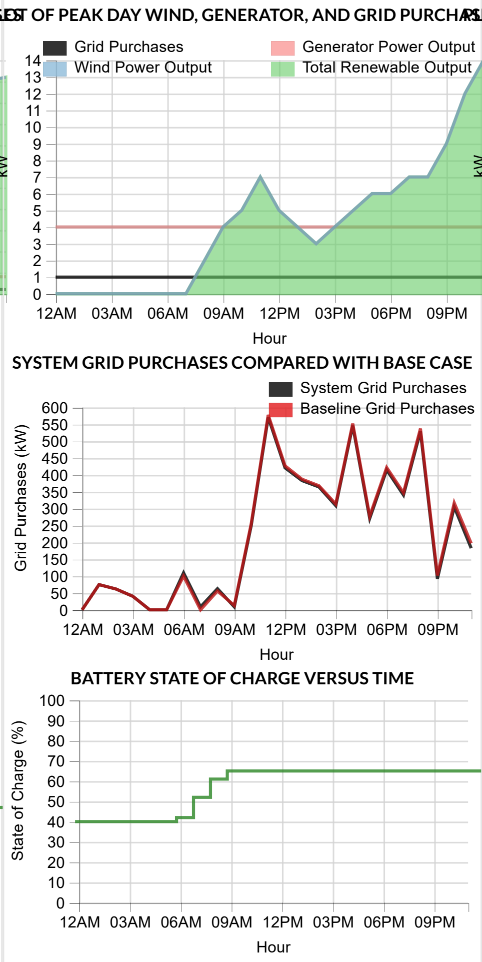
SEPTIEMBRE



OCTUBRE



NOVIEMBRE



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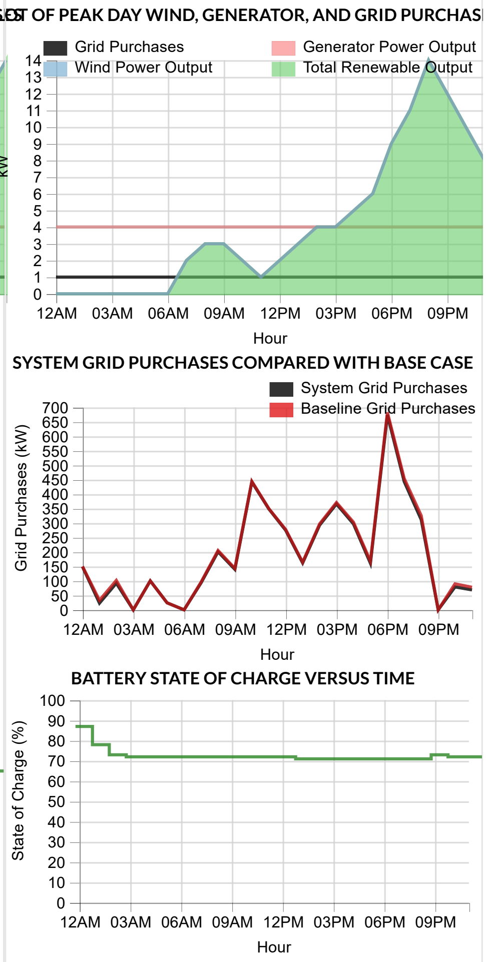

Monthly Carbon Dioxide Emissions: System #5

	January	February	March	April	May	June	July	August	September	October	November	December
Monthly Total (metric tons)	51 t	53 t	55 t	53 t	60 t	55 t	56 t	61 t	49 t	49 t	51 t	57 t
Annual Total (metric tons)	651 t/yr											

* emissions are based on an assumption of your grid's generation sources.

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