POLITECNICO DI TORINO

Master of science program in Energy and Nuclear Engineering

Renewable Energy Systems

Master Thesis

Energy recovery project for the new headquarters of a National Park: comparison between electric and hydrogen mobility on Pantelleria island

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Abstract

The utilization of renewable energy sources and new sustainable types of transport are the key to a faster energy transition and decarbonization of society.
The aim of this master thesis is the comparison between two public transport infrastructures, electric and hydrogen, on Pantelleria island. The study comprehends the resource assessment and the sizing of two renewable energy power plants, a building integrated PV system and a small wind turbine, near the new National Park headquarters with the goal of having an on-site production of electricity and hydrogen.
Regarding the hydrogen mobility infrastructure, the electricity generated from RES is used to produce hydrogen by means of a Polymer Electrolyte Membrane (PEM) electrolyzer; the H_2 is then stored in a low-pressure tank, compressed, and stored again in high-pressure cascade tanks which facilitate the dispensing of hydrogen in the Fuel Cell buses. On the other hand, in the electric mobility infrastructure, the electricity produced is directly stored in Lithium-ion batteries and then dispensed to the electric buses.
After the dimensioning of three different plant sizes in both cases, a techno-economic simulation/optimization of the two infrastructures is carried out on PyPSA, trying to find the right compromise between performance and costs, in other words satisfying buses demand in the best possible way, minimizing the investment.
The LCOH (between 20 – 25 €/kg, 21.4 €/kg with the optimization) and the LCOEV (between 0.21 – 0.29 €/kWh, 0.27 €/kWh with the optimization) evaluated are in line with the ones found in literature, while the PBT is about 10 years for the H_2 case and about 7 years for the electric case. Therefore, the results of this thesis show that at the moment the electric solution is the most advantageous, but with the proper incentives and improvements in efficiency, hydrogen mobility infrastructures will certainly be competitive (LCOH between 4 and 6 €/kg) and have a good share of the market together with the electric mobility infrastructure.

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Acronyms

RES	Renewable Energy Sources
GHG	Greenhouse Gases
ESS	Energy Storage Systems
EV	Electric Vehicle
CCS	Carbon Capture and Storage
PEM	Polymer Electrolyte Membrane
SOEC	Solid Oxide Electrolytic Cell
PV	Photovoltaic
QGIS	Quantum Geographic Information System
UMEP	Urban Multi-scale Environmental Predictor
DSM	Digital Surface Model
SEBE	Solar Energy on Building Envelopes
GWC	Generalized Wind Climate
WAsP	Wind Atlas Analysis and Application Program
GWA	Global Wind Atlas
PVGIS	Photovoltaic Geographic Information System
AEP	Annual Energy Production
SOC	State of Charge
LCOH	Levelized Cost of Hydrogen
LCOEV	Levelized Cost of Electric Vehicle
CAPEX	Capital Expenditure
OPEX	Operational Expenditure
BEC	Bare Erected Cost
EPCC	Engineering, Procurement and Construction Cost
TPC	Total Plant Cost

TOC	Total Overnight Cost
O&M	Operation and Maintenance
COH	Cost of Hydrogen
COE	Cost of Electricity
CCF	Capital Charge Factor
CF	Capacity Factor
PyPSA	Python for Power System Analysis
PBT	Payback Time
FCD	Fuel Cell Dominant
BEV	Battery Electric Vehicle

1. Introduction

In the last decades, the word "energy transition" has become more and more part of our vocabulary. This stems from the urgent need to take concrete actions against climate change. The energy transition is the process of replacing fossil fuels energy sources with renewable energy sources (RES) or other sustainable fuels like hydrogen. The ultimate goal of this process is the "carbon-neutrality" of our society, which can be achieved by reducing or better eliminating the greenhouse-gases emissions, of which the carbon dioxide (CO_2) is the most important. The GHG emissions, and consequentially the energy transition, are related to the production, distribution, and consumption of energy, to different sectors like electricity and heat production, industry, transport, buildings and agriculture.

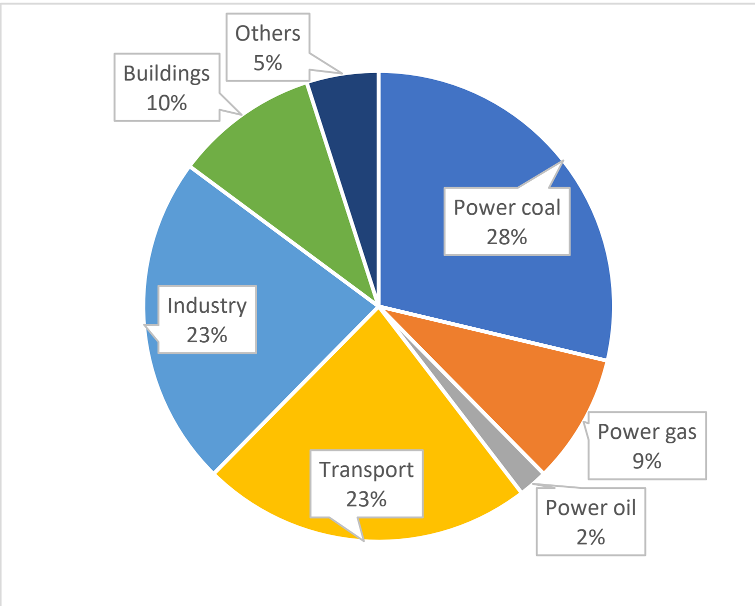

Figure 1.1 Global energy-related CO2 emissions by sector [1]

The potential of renewables has been known for years, but also their criticalities: the intermittence of energy sources (sun and wind) and a lower energy density compared to conventional sources. For this reason, the studies have focused on the capacities of Energy Storage Systems (ESS), but also on other energy vectors or sustainable fuels with very low or zero environmental impact that can "help" renewable sources in the decarbonization of the energy production sector, amongst these there is the hydrogen. The latter, as a fuel, is known because it is already used for space missions thanks to its high energy density. But the more important feature of the hydrogen is the zero-emissivity, and for this reason, in the energy sector but also in the transport sector, it is already considered by many as the key to a net-zero society. In this thesis, a comparative assessment of zero emission electric and hydrogen buses will be carried out [35].

1.1 The future of public transport: Hydrogen vs Electric

Public mobility plays a significant role in the greenhouse gases emissions from the transport sector. The electrification or the use of sustainable fuels could decarbonize it. The transition from unsustainable to sustainable public transport will be analyzed in the following chapter. In particular, the techno-economic differences between an electric or hydrogen bus mobility infrastructure for the island of Pantelleria, from the on-site production of electricity from renewable sources to the storage of it in case of electric mobility or to the storage of H_2 in the case of hydrogen, up to their dispensing.

The electric mobility infrastructure is the simpler and more mature of the two. The technologies implemented are already used in a vast scale. The rechargeable battery is the core of the plant and could be of different types: lead–acid is the first ever created and the most used specially in vehicles, nickel–cadmium (NiCd), nickel–metal hydride (NiMH), lithium-ion (Li-ion) and others. Li-ion batteries are the most recent and their deployment is growing faster than the others, they are characterized by high energy density, no memory effect, low self-discharge and compared to the lead-acid type they cover less space for the same amount of capacity, have a longer life and have a faster charge/discharge rate [4]. Therefore, they are selected for this study.

The above-mentioned four main technologies of electrochemical rechargeable batteries are only a part of the ESS, which are increasing their importance in the electricity supply world. Among the ESS under development and deployment there are those concerning hydrogen.

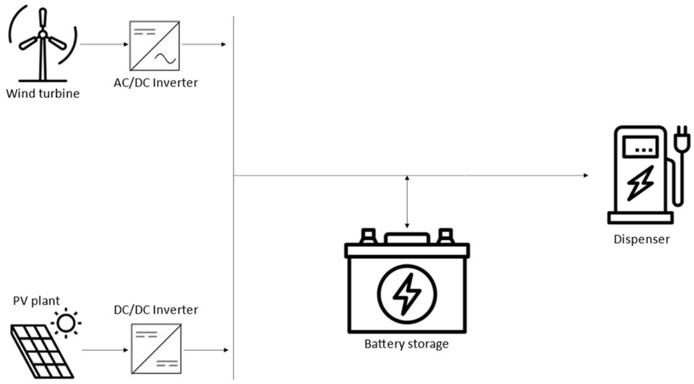

Figure 1.2 Electric mobility infrastructure [2] [3]

The hydrogen mobility infrastructure has the potential to challenge the conventional ones and the electric one. Its best characteristic is the mileage of vehicles compared to the EV and a faster charging. But the sustainability of hydrogen infrastructure is strictly related to its production. In fact, there are different ways to produce it and the subdivision is made by means of colors:

- Green hydrogen: it is produced on a CO_2-neutral basis through the electrolysis of water. The electricity required by the electrolyzer is generated from renewable energy sources.
- Blue hydrogen: it is generated from the steam reduction of natural gas. The emitted CO_2 is not released in the atmosphere but stored with Carbon Capture and Storage (CCS). It could be considered as a climate-neutral technology, but the impacts of storage (usually underground) and leakage can still negatively affect the environment and climate.
- Grey or brown hydrogen: it is obtained by steam reforming fossil fuels such as natural gas or coal. Here, the CO_2 emitted is released in the atmosphere and then is the opposite of green hydrogen, because it is not climate neutral.

There are other colors that characterize the hydrogen production depending on the source (i.e., nuclear), but the main three are the above-mentioned. Since the hydrogen that will be produced in the case-study infrastructure is the green hydrogen, an electrolyzer to split water ($H_2O \rightarrow H_2 + 1/2O_2$) will be used. There are three main types of electrolyzer that dominate the market:

- Alkaline electrolyzer: it uses an alkaline solution as electrolyte. Nowadays, it is the cheapest in the market.
- Polymer Electrolyte Membrane (PEM) electrolyzer: it uses NAFION membranes as electrolyte. This technology is more expensive than the alkaline one, but better in terms of performances and footprint.
- Solid Oxide Electrolytic Cell (SOEC): it uses a solid ceramic material as electrolyte. It is the best in terms of efficiency, but still the most expensive. Furthermore, this type of electrolyzer works at high temperatures, which makes it unsuitable for coupling with intermittent renewable energy sources such as solar and wind, because it would take a long time to reach the operating temperature.

For being more suitable with RES and cheaper than the SOEC type, the electrolyzer of the PEM type is the selected one for this study.

For what concerns the storage of hydrogen, many methods have been studied and adopted [36]. The main division is between physical-based and material-based storage. Amongst the numerous chemical or material-based storage methods, the ones based on metal hydrides (i.e., MgH2, NaAlH4, LiAlH4, LiH) are gaining interest with various studies in progress, but the most established technologies are the physical-based:

- Compressed H_2: hydrogen is compressed up to 700 bar (even 1000 bar in some prototypes) in spherical or cylindrical vessels. This technology is the cheapest and the most used nowadays.
- Liquefied H_2: hydrogen is liquefied at cryogenic temperatures (-253 °C). The main characteristic of this technology is the high energy density coupled however with high liquefaction costs and evaporation losses.

For the economic aspect and the technological maturity, the compressed gas technology is the one chosen for this study.

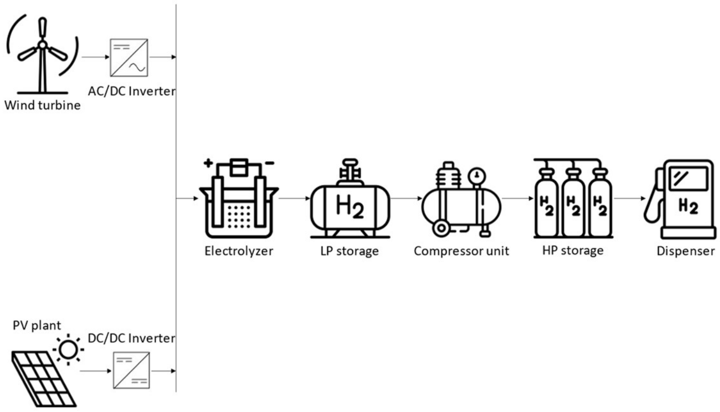

Figure 1.3 Hydrogen mobility infrastructure [2] [3]

2. Territorial context

Pantelleria is an island situated in the middle of the Mediterranean Sea, 100 kilometers southwest of Sicily. The island administratively belongs to the Sicilian province of Trapani. Pantelleria’s National Park is the first in Sicily and covers 80% of the island's surface [5]. The study project involves the conversion of a part of the military area located in Bukkuram, in the new headquarters of the National Park and the recovery of the remaining area within the borders to allow for it a new use: the electricity production from RES and the new public mobility infrastructure.

In Figure 2.1 the site in Bukkuram is divided into the new headquarters area highlighted in violet, the buildings in orange, and the ex-military area in green.

Figure 2.1 Military area in Bukkuram, new headquarter of the National Park

2.1 Public transport in Pantelleria

The bus lines of the island connect the center of the municipality of Pantelleria with the main places of interest for the inhabitants and tourists like the airport, the areas of Tracino, Bugeber, Rekale and Sibà. The lines are in number of five, while the buses are four [6].

Before estimating the transport demand, some assumptions have been made; in order to improve the public network, the number of buses have been increased to seven, one for each route and then one more for the two longest lines: Pantelleria-Tracino and Pantelleria-Rekale.

Being a summer tourist destination, the hypothesis was to increase the trips to the airport on summer weekdays and to leave the travels active - even if reduced – on summer holidays, as opposed to what happens for the rest of the year, when on Sundays and holidays the buses are stopped. Another hypothesis is not to make races on the patron's day, which is held on October 16.

SUMMER WEEKDAYS					
BUS LINES	**N. Travels**	**KM TOTAL (daily)**	**N. Bus**	**KM BUS 1**	**KM BUS 2**
Pantelleria-Tracino	14	175	2	100	75
Pantelleria-Bugeber	4	38	1	38	
Pantelleria-Aeroporto-Bukkuram-Sibà	8	88	1	88	
Pantelleria-Aeroporto	14	68.6	1	68,6	
Pantelleria-Rekale	14	240.8	2	137.6	103.2

SUMMER HOLIDAYS					
BUS LINES	**N. Travels**	**KM TOTAL (daily)**	**N. Bus**	**KM BUS 1**	**KM BUS 2**
Pantelleria-Tracino	10	125	2	75	50
Pantelleria-Bugeber	4	38	1	38	
Pantelleria-Aeroporto-Bukkuram-Sibà	6	66	1	66	
Pantelleria-Aeroporto	10	49	1	49	
Pantelleria-Rekale	10	172	2	103.2	68.8

FROM SEPTEMBER TO JUNE					
BUS LINES	**N. Travels**	**KM TOTAL (daily)**	**N. Bus**	**KM BUS 1**	**KM BUS 2**
Pantelleria-Tracino	14	175	2	100	75

Pantelleria-Bugeber	4	38	1	38	
Pantelleria-Aeroporto-Bukkuram-Sibà	8	88	1	88	
Pantelleria-Aeroporto	12	58.8	1	58.8	
Pantelleria-Rekale	14	240.8	2	137.6	103.2

Table 2.1 Summary of bus lines of Pantelleria, divided in summer (weekdays and holidays) and the rest of the year

After all the hypothesis, to evaluate the transport demand both for the hydrogen and the electric case, the choice of minibuses that will be used is of great importance, as the daily demand follows from the energy consumption of the two types of buses.

The fuel cell minibus of the Italian company Dolomitech s.r.l. was chosen for the hydrogen infrastructure, it is 7 meters long and can carry up to 16 people plus the driver. It is characterized by an autonomy of 250 km and a hydrogen consumption of 2.8 kg/100km [7]. A summary of the main characteristics is shown in Table 2.2.

Minibus Dolomitech FCD (Fuel Cell Dominant)		
Length	7	meters
Seats	16	
Fuel consumption	2.8	kg/100km
Autonomy	250	km
Tank capacity	7	kg
Maximum velocity	80	km/h
Tank pressure	350	bar

Table 2.2 Characteristics of FCD Dolomitech's minibus

The 6 meters long minibus Rampini E60 was selected for the electric mobility. It can carry up to 30 people plus the driver and has an autonomy similar to the previous one [8]. The main characteristics are summarized in Table 2.3.

Minibus Rampini E60		
Length	6	meters
Seats	31	
Power	122	kW
Autonomy	250	km

Battery	210	kWh
Maximum Velocity	63	km/h
Consumption	1	kWh/km

Table 2.3 Characteristics of the totally electric Rampini E60 bus

The daily consumption was calculated considering the kilometers traveled everyday by each bus and their fuel consumption, therefore for the hydrogen buses the daily need is in kg, while for the electric buses in kWh. In the following graphs the demands are plotted on an annual basis.

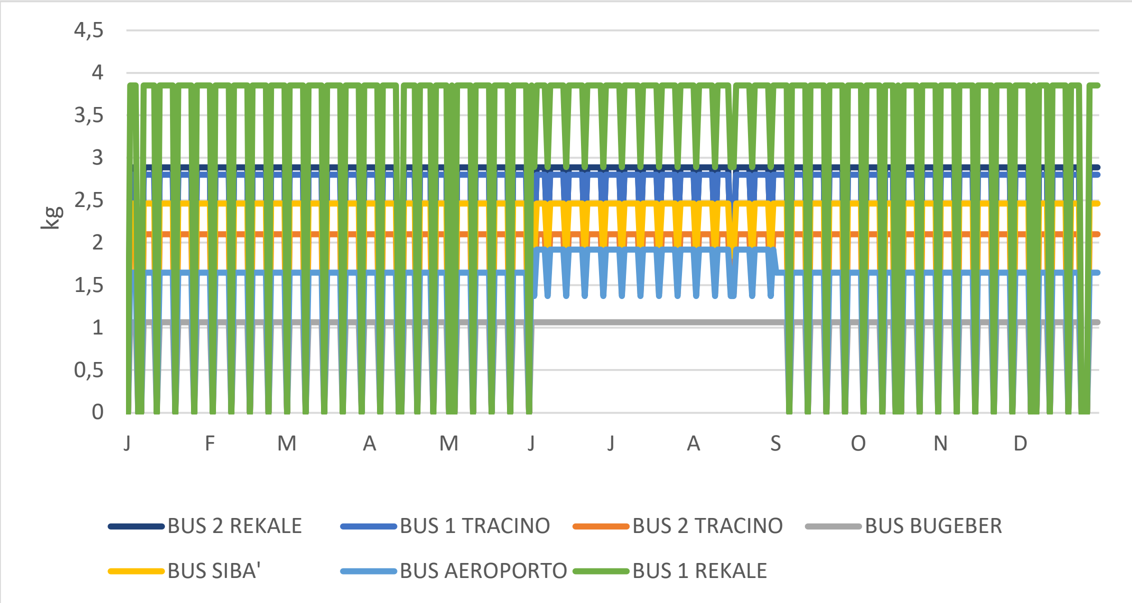

Figure 2.2 Total daily hydrogen consumption per bus

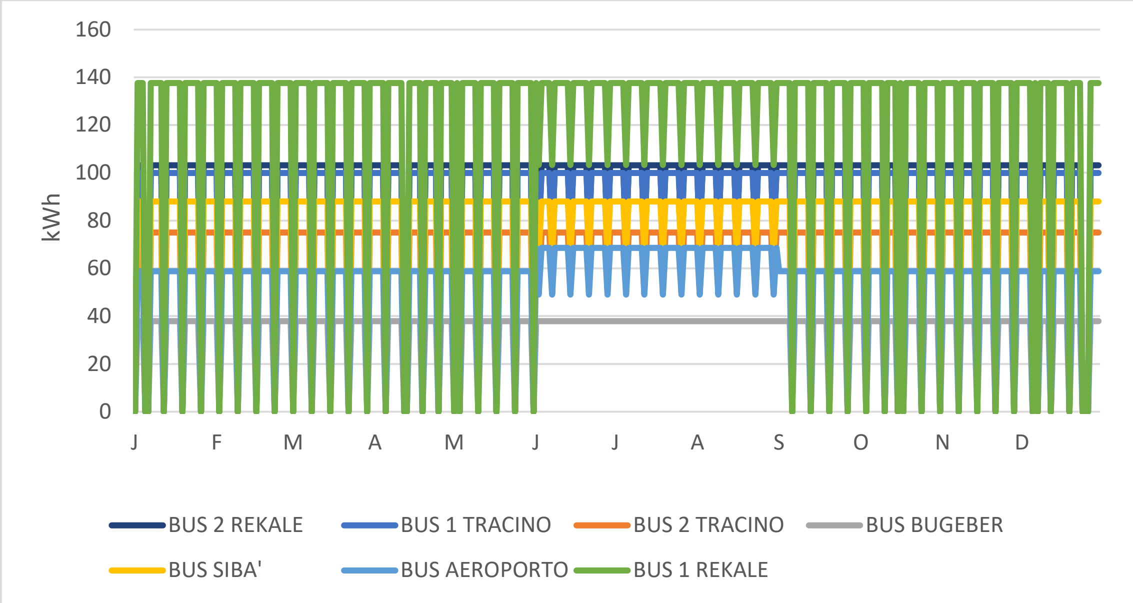

Figure 2.3 Total daily electricity consumption per bus

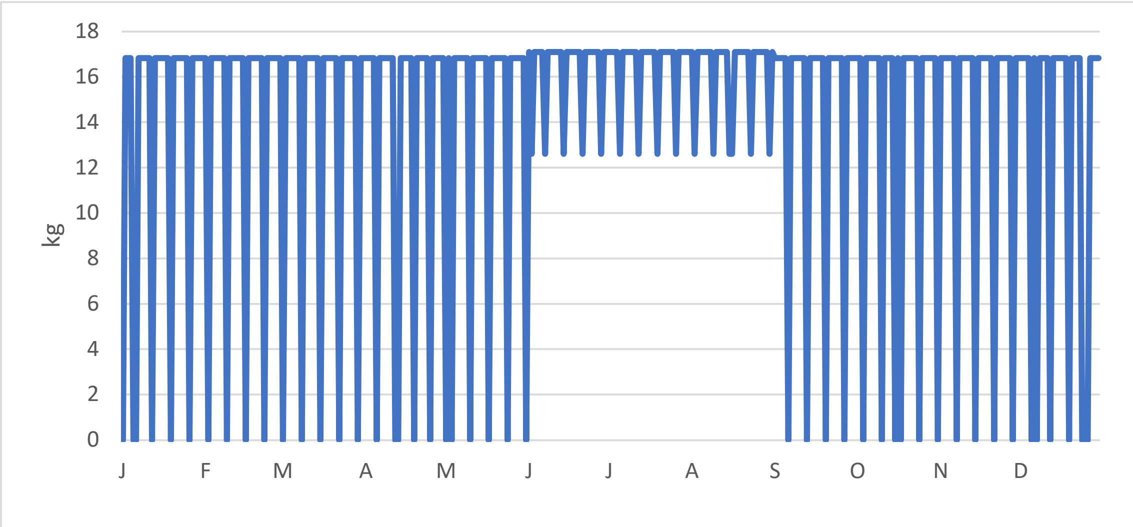

Figure 2.4 Total daily hydrogen consumption

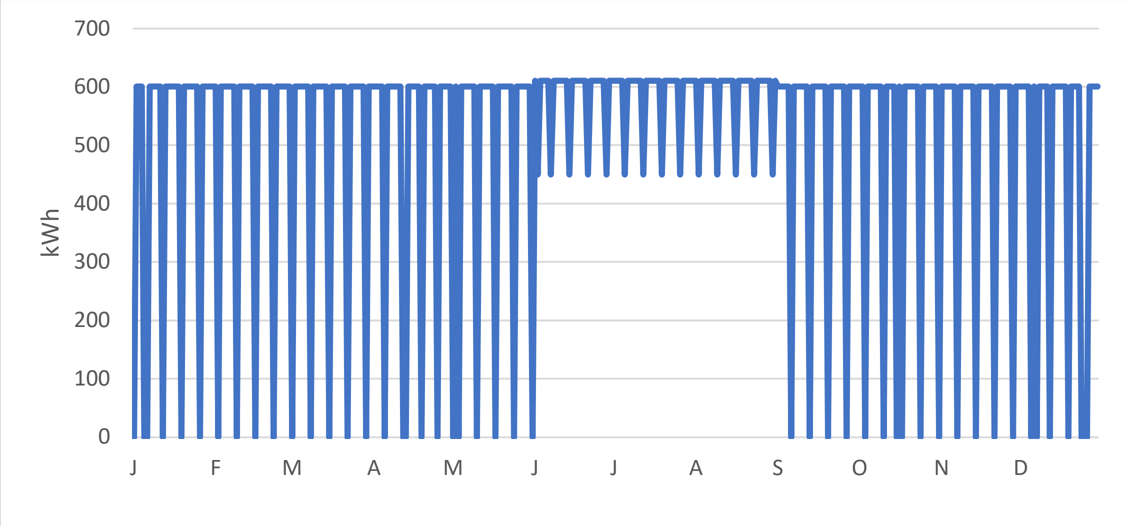

Figure 2.5 Total daily electricity consumption

2.2 Renewable Energy Sources availability

Solar and wind resources evaluation at the National Park site is a key step in order to assess the producibility and to size the photovoltaic and wind power plant. Pantelleria, located in the center of Mediterranean Sea, is a sunny island with an average solar irradiation of 1,750 kWh/m² and it is situated in one of the windiest areas in the Mediterranean with sea winds that blow impetuously in every season, among which Scirocco and Mistral prevail [5]. Therefore, talking about renewable energy sources, Pantelleria is one of the places with more potential in the whole Italian peninsula, also considering the exploitation of the marine wave energy.

2.2.1 Solar resource

QGIS plug-in UMEP (Urban Multi-scale Environmental Predictor) was used to examine the solar resource over the National Park site [24][9]. The PV modules will be positioned on the roofs of the small buildings shown in Figure 2.1., therefore the solar radiation will have to be calculated in particular for each pitch and according to their orientation.

UMEP is composed of three main elements: pre-processor (for inputs of meteorological and surface data), processor (with plug-ins to model determinate systems) and post-processor (with tools to visualize the outputs of the system) [10].

After importing the DSM (Digital Surface Model) files with buildings and ground of the island of Pantelleria, the meteorological dataset from the Copernicus program have been prepared and imported to UMEP [11]. The term “preparation” of meteorological data refers to the conversion of the ERA5 file in a “.txt” file needed by UMEP and the calculation of determinate data like the shortwave radiation components, temperature, pressure, etc.

To assess potential solar energy production, the SEBE (Solar Energy on Building Envelopes) plug-in can calculate and then visualize irradiances at pixel resolution on building roofs and walls [12]. To do the properly calculations, this plug-in needs the building and ground DSM, meteorological data, albedo, a wall height, and a wall aspect (i.e., angle) raster which can be created directly with UMEP. Running SEBE, a raster showing irradiance on ground and building roofs is generated (Figure 2.6).

By cutting out the roofs of the buildings under study from the created raster, we can calculate the irradiation on each pitch as an average of the pixels over that pitch.

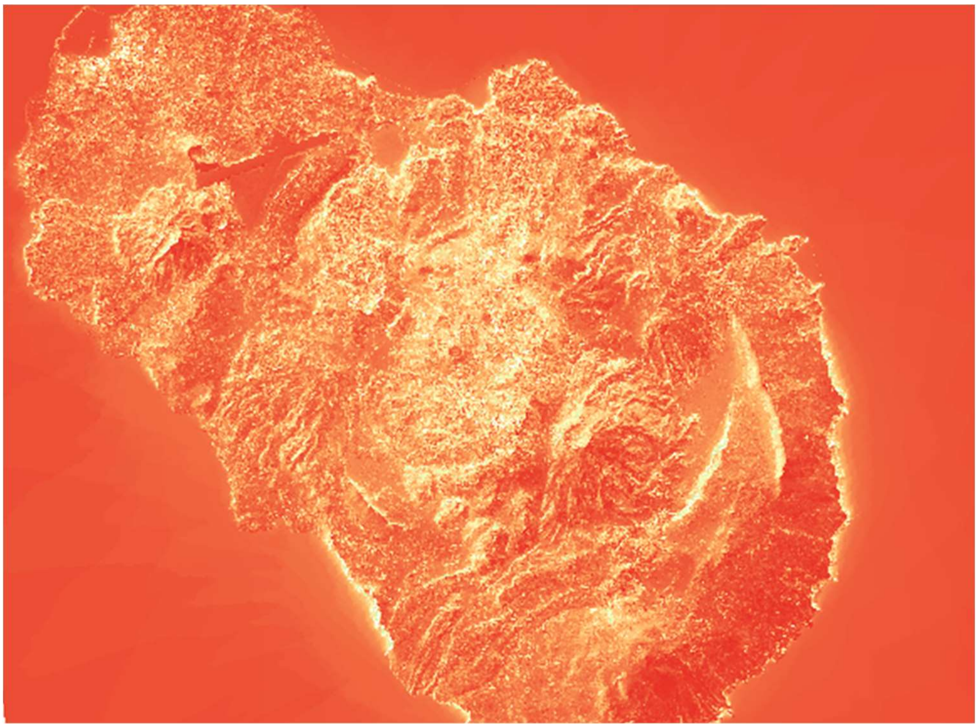

Figure 2.6 Raster of solar irradiance on ground and building roofs for Pantelleria

Figure 2.7 Irradiation over each roof's pitch

Layer	Irradiation, kWh/m²
Pitch1	1,753.5
Pitch2	1,617.2
Pitch3	1,694.9
Pitch4	1,591.9
Pitch5	1,962.7
Pitch6	1,532.2
Pitch7	1,766.8
Pitch8	1,650.0
Pitch9	1,918.8
Pitch10	1,517.6
Pitch11	1,807.4
Pitch12	1,633.2
Pitch13	1,965.0
Pitch14	1,751.8
Pitch15	1,846.4

Pitch16	1,680.4
Pitch17	2,028.0
Pitch18	1,768.7

Table 2.4 Irradiance value for each pitch

2.2.2 Wind resource

The area of Pantelleria is one of the richest in wind resource of the Mediterranean Sea. At 50 meter above ground level, the mean wind speed is around 8.5 m/s, while the power density around 850 W/m². These data come from the Global Wind Atlas, which together with maps will be imported, as Generalized Wind Climate (GWC) files, in WAsP, which is the software used for wind resource assessment, siting and energy yield calculations for wind turbines and wind farms [13] [14]. WAsP contains flow models for orography, roughness and roughness change effects, and, unlike GWA, obstacle effects [15].

A map displaying the mean wind speed is shown in Figure 2.8, it can be noticed that the average is around 7-9 m/s as said before. From Figure 2.9 by means of the wind rose of Pantelleria and then in particular of the Natural Park site it can be seen that the prevailing winds are those coming from the north-west (Mistral) and south-east (Scirocco).

The choice of the turbine and the evaluation of the producibility will be described more precisely in the next chapter.

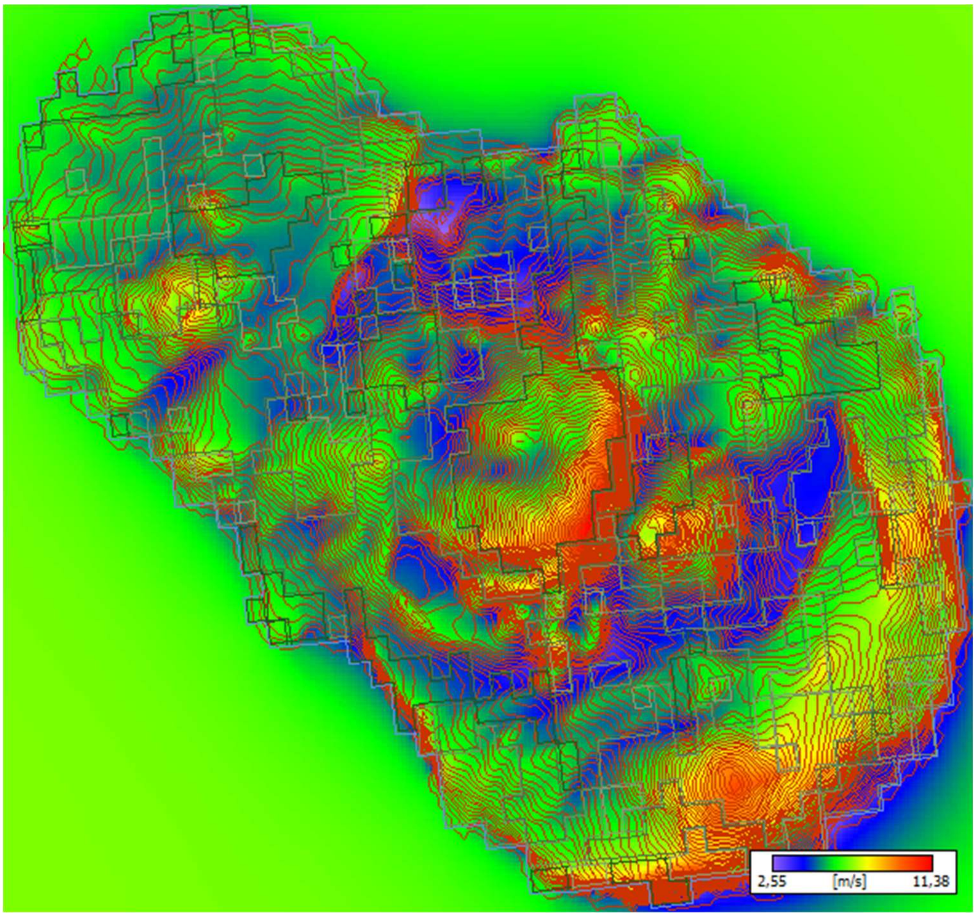

Figure 2.8 Mean wind speed map

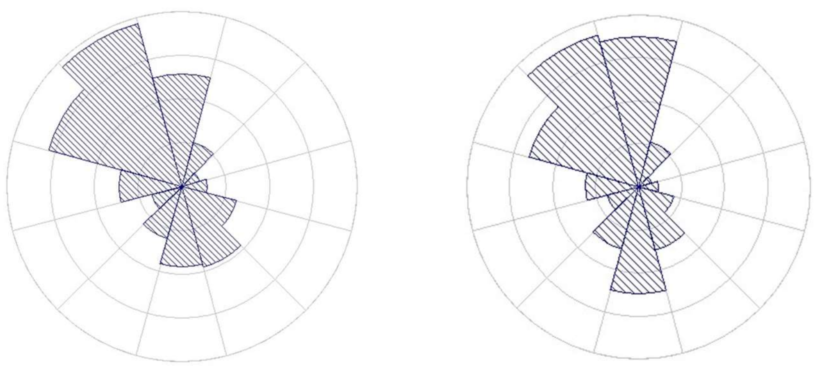

Figure 2.9 Wind roses of Pantelleria (left) National Park (right)

3. Renewable power plants sizing

After the resources assessment in the National Park area, the production evaluation is the next step. For both plants, an hourly and a daily production profile will be evaluated starting from the yearly producibility calculated for both plants and scaled with general data for Pantelleria imported from PVGIS and Renewables.ninja, online software used for the producibility assessment for PV plant and wind power plant respectively [16] [17].

3.1 Sizing of the PV plant

As said in the paragraph 2.1 the PV modules will be installed on the roofs of the buildings. The chosen PV panel is the monocrystalline Jinko Tiger 78TR 480 W, it is ideal for the residential installations, has an area of about 2.25 m² and a good efficiency of 21.38 % [18].

The number of modules that can be installed on a pitch is evaluated using AutoCAD, creating a model of the panel with the measures taken from the datasheet [19]. Considering that all the pitch's surface can be used, given the small height of the buildings, which allows an easy installation, the number of modules that can be installed on a single pitch is 12. Therefore, multiplying it for two and for the number of buildings, the total number of modules can be calculated. In Table 3.1 the results are summarized, with also the peak power.

	Modules	**Power [kWp]**
Pitch	12	5.8
Roof	24	11.5
Total	216	103.7

Table 3.1 Number of modules and peak power calculation

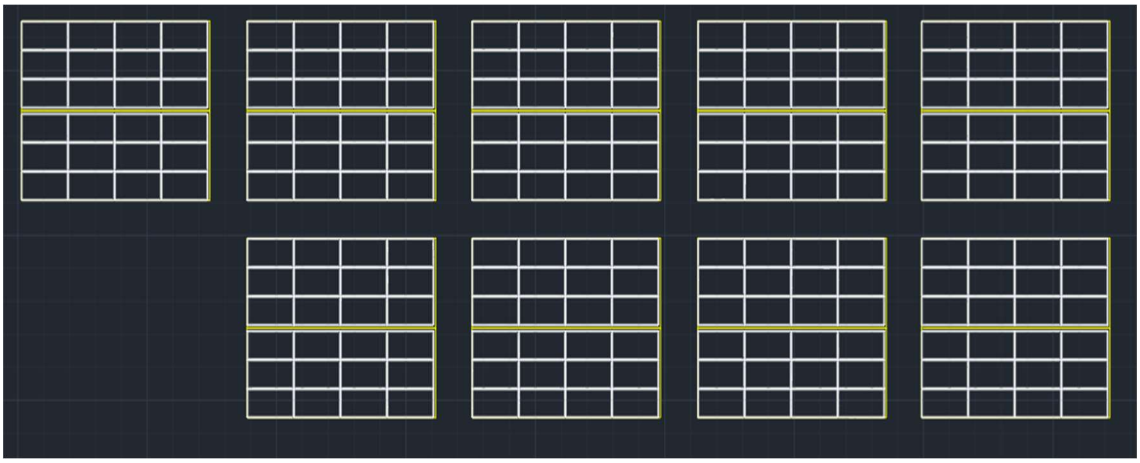

Figure 3.1 Modules disposition

The selection of the inverter was made following two main criteria: optimize the space where to install them and match the peak power above a building with the peak power of the inverter. Therefore, installing one inverter per building, above which the peak power is 11.5 kWp, an inverter with a power output of about 12 kW must be selected: the choice fell on the Huawei SUN2000-12KTL-M0 which is a three-phase inverter with an operating voltage range between 160 – 950 V. The utilization ratio is around 96%, so it is ok because the usual recommendation is to have a utilization ratio > 95%. Having this inverter 2 MPPT ports, the two pitches of a building can be connected simultaneously to it [20][21].

Now the annual producibility of the plant can be calculated with the formula:

$$E_{AC} = P_N \cdot \frac{H_g}{G_{STC}} \cdot PR$$

With nominal power of the plant P_N = 103.7 kWp, average global irradiance H_g = 1,749.1 kWh/m², irradiance in standard condition G_{STC} = 1000 W/m² and the performance ratio of 0.88 taking in consideration the various losses of a photovoltaic plant, the annual productivity of the plant is of 159,961 kWh ≈ 160 MWh.

	Annual Production
Pitch1	8,908.5
Pitch2	8,215.8
Pitch3	8,610.8
Pitch4	8,087.1
Pitch5	9,971.3
Pitch6	7,783.9
Pitch7	8,976.0
Pitch8	8,382.3
Pitch9	9,747.9
Pitch10	7,710.1
Pitch11	9,182.2
Pitch12	8,297.0
Pitch13	9,982.8
Pitch14	8,899.9
Pitch15	9,380.2
Pitch16	8,536.8
Pitch17	10,302.8
Pitch18	8,985.5
TOTAL	**159,961.0**

Table 3.2 Annual production per pitch and total plant

Scaling the annual production with hourly and daily production data from PVGIS by means of a MATLAB code, an hourly and a daily production profile for the case-study PV plant is evaluated and the daily one is shown in Figure 3.2 [22].

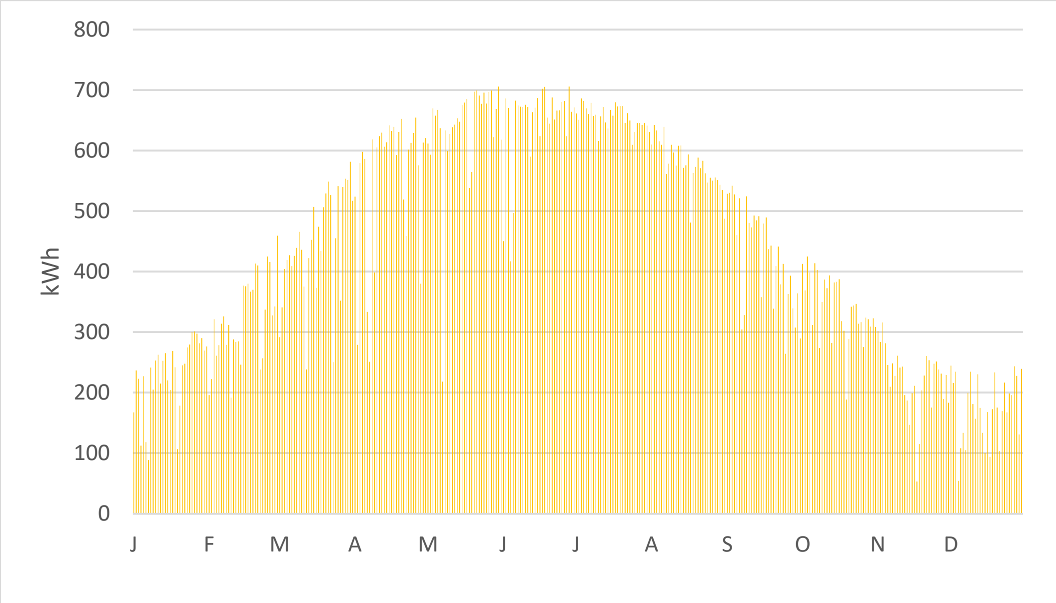

Figure 3.2 PV plant's daily production profile

3.2 Sizing of the onshore wind plant

The wind farm is actually just a small turbine. The choice is due to the fact that the positioning of the plants is limited to the park area and to the various limitations on large wind turbines in force in Pantelleria.

The selected turbine is the Rago Freccia 59/23,2, it is a 30 meters height, horizontal axis, three-blade turbine working in up-wind position, the rotor diameter is of 23.2 m and with a rated wind speed of 9.5 m/s this turbine can reach a rated power of 59 kW, the cut-in and cut-off wind speed are respectively of 2.5 and 25 m/s [23].

The turbine is placed following criteria of space and producibility, in fact it is positioned using WAsP in the northernmost and highest position on the hill in the park area.

Figure 3.3 Turbine site on Google Earth [25]

By inserting the power curve of the turbine on WAsP, the Annual Energy Production (AEP) can be calculated, and it is of 223,611 kWh ≈ 224 MWh. In Figure 3.4 is shown the wind power density map for Pantelleria, but in particular the AEP rose for the positioned turbine.

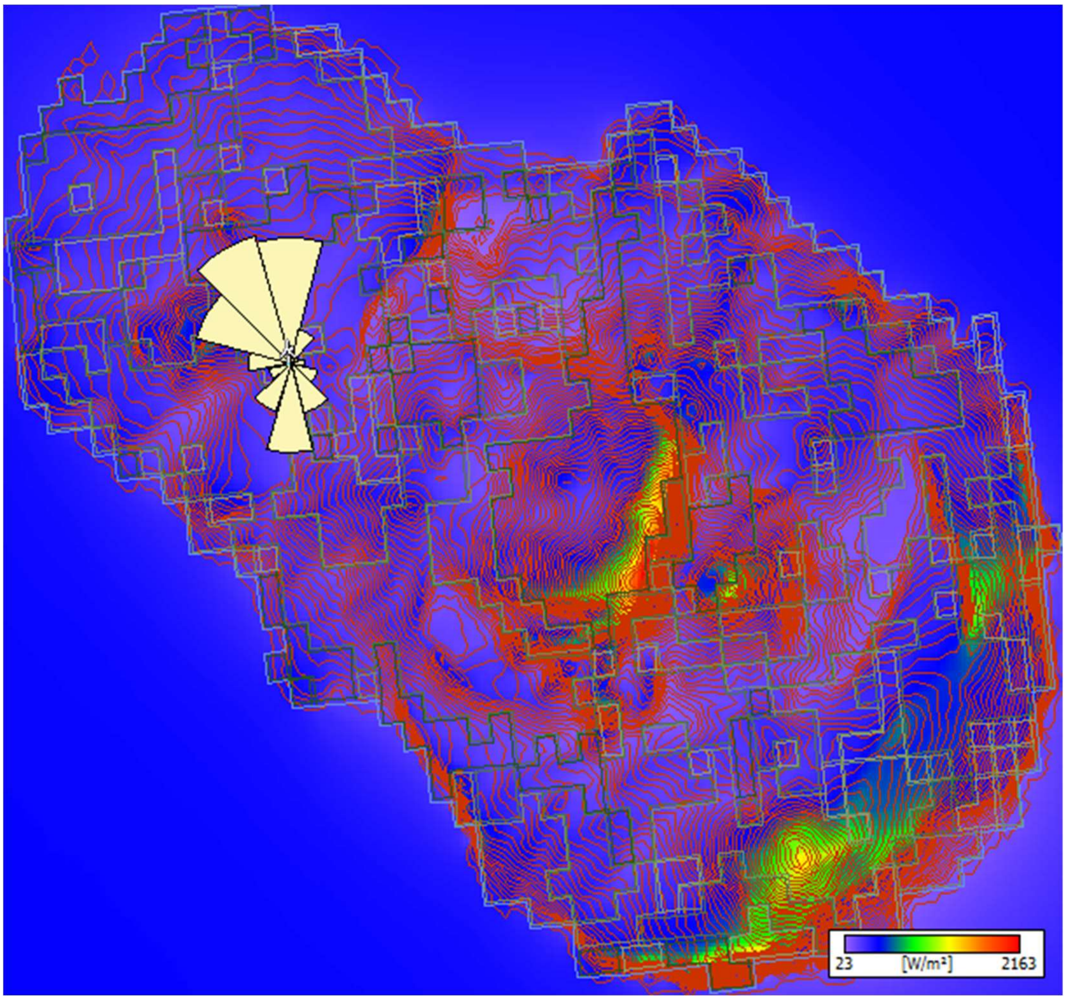

Figure 3.4 Power density map with AEP rose

As made previously with the photovoltaic plant, scaling the annual production with hourly and daily production data from Renewables.ninja by means of a MATLAB code, an hourly and a daily production profile are evaluated for the wind turbine plant.

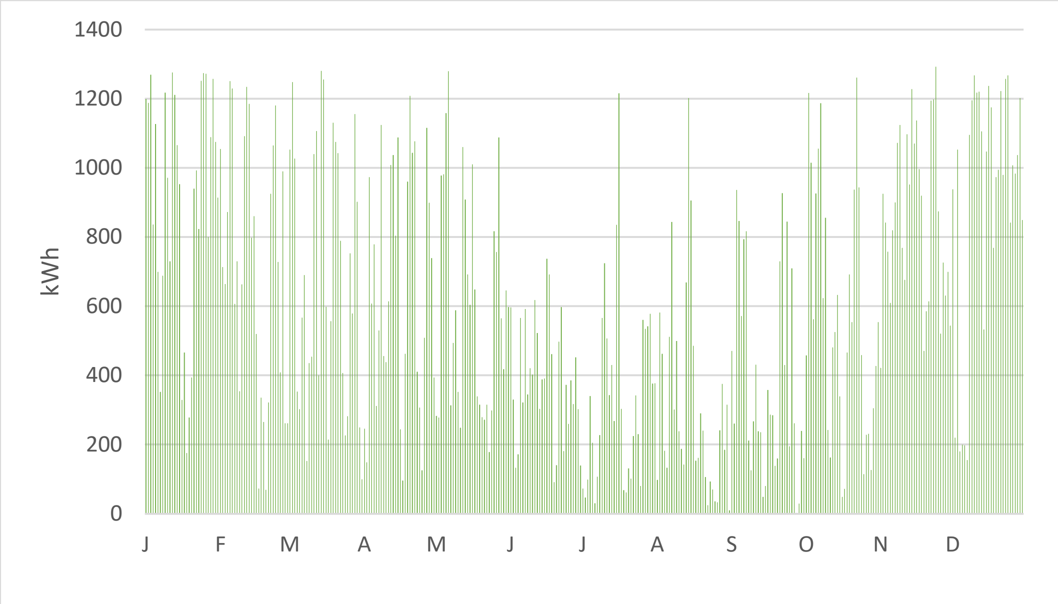

Figure 3.5 Wind turbine's daily production profile

The electricity production from RES will be the energy source for the hydrogen and electricity mobility infrastructures which will be analyzed in the next chapters. Since the total annual production is the sum of the two renewable plants, if for the PV plant is 159,961 kWh and for the wind turbine is 223,611 kWh, a total of 383,572 kWh ≈ 384 MWh is produced, and a total production profile is calculated.

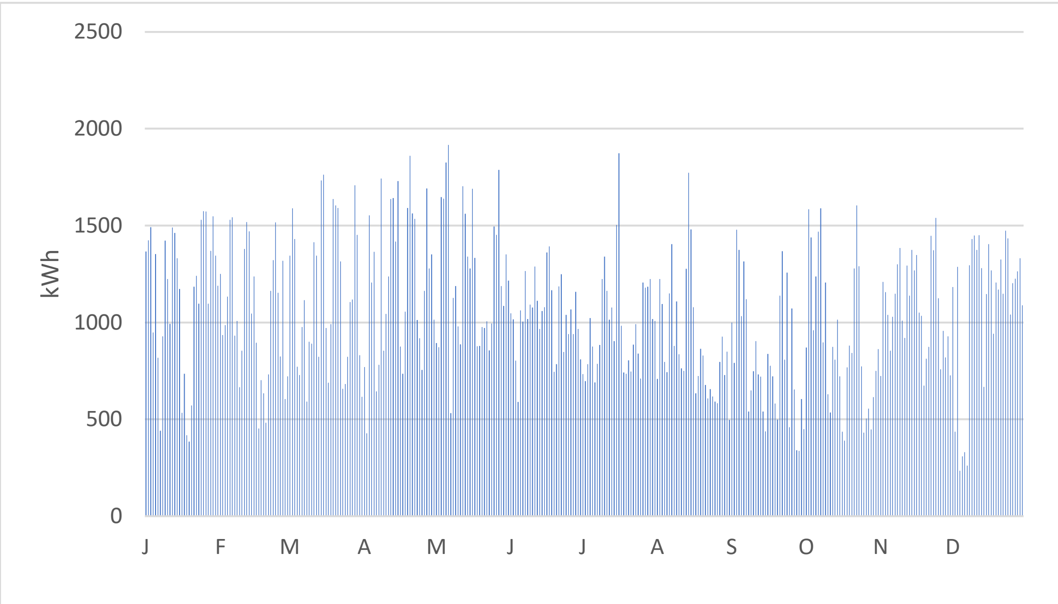

Figure 3.6 Total daily production profile from RES

4. Hydrogen and electric mobility infrastructures

In this chapter the case-study infrastructures are presented and analyzed. The production of H_2 with different sizes of electrolyzers is calculated and its storage and dispensing are studied with various tank sizes [29-34]. The same is performed for the electric infrastructure with the modelling of the battery.

4.1 Hydrogen production, storage and dispensing

The process chain of the H_2 mobility infrastructure was described in Figure 1.4 and it is summarized below.

1) The hydrogen is produced at 30 bar from the electrolysis of water using the electricity produced by RES (Green H_2)
2) Stored in low-pressure storage tank at 30 bars
3) Compressed from 30 to 500 bar in the compressor unit
4) Stored in high-pressure cascade tanks at 500 bar
5) Dispensed at 350 bar in the Dolomitech's buses

In the next paragraphs all this infrastructure is described in detail.

4.1.1 Electrolyzer

The electrolyzer is basically the hydrogen generator; it uses the electricity to split water in H_2 and O_2. In order to perform an analysis, following the state of the art of electrolyzers [26][27], on the production of hydrogen, three commercial models of PEM electrolyzer have been selected. These are the C-Series electrolyzers of Nel Hydrogen, a global leader company which provides solutions for the production, storage and distribution of hydrogen from renewable energy sources [28]. These medium-sized models have been chosen because the nominal daily production rate of hydrogen is similar to the daily demand of the buses. In fact, as can be noted from Table 4.1, the C10 electrolyzer has a nominal production rate of 21.6 kg/day, while the maximum daily demand is around 17.1 kg in summer weekdays. The economic feasibility and profitability of the storing of hydrogen will be studied considering that the production will not always be at its nominal rate.

Model	Power input, kWe	Electrolyzer efficiency	Energy consumpion, kWh/kg	Energy consumpion, kWh/Nm³H₂	Lifetime	Production rate, Nm³/h	Production rate, kg/h
C10	70	57%	68.9	6.2	20	10	0.9
C20	120	59%	66.7	6	20	20	1.8
C30	180	61%	64.5	5.8	20	30	2.7

Table 4.1 Main characteristics of the C-Series PEM electrolyzers

From the hourly, daily and monthly electricity production profile, the hydrogen production profiles are generated. The H_2 produced is calculated by dividing the energy from RES for the energy consumption per mass or volume of hydrogen which characterizes the electrolyzers.

From the average daily production of hydrogen can be seen that the daily demand of 16.8 kg_{H2} (with a maximum of 17.1 kg_{H2}) will not always be matched, and the need of a bigger storage tank is higher for the 70 kW electrolyzer than for the 180 kW one.

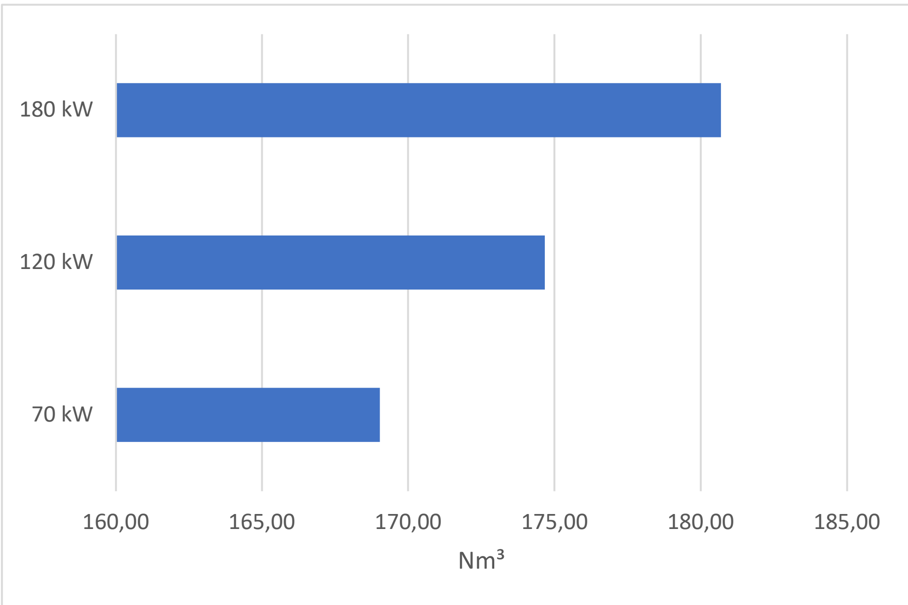

Figure 4.1 Average daily production of H_2 per electrolyzer in Nm^3

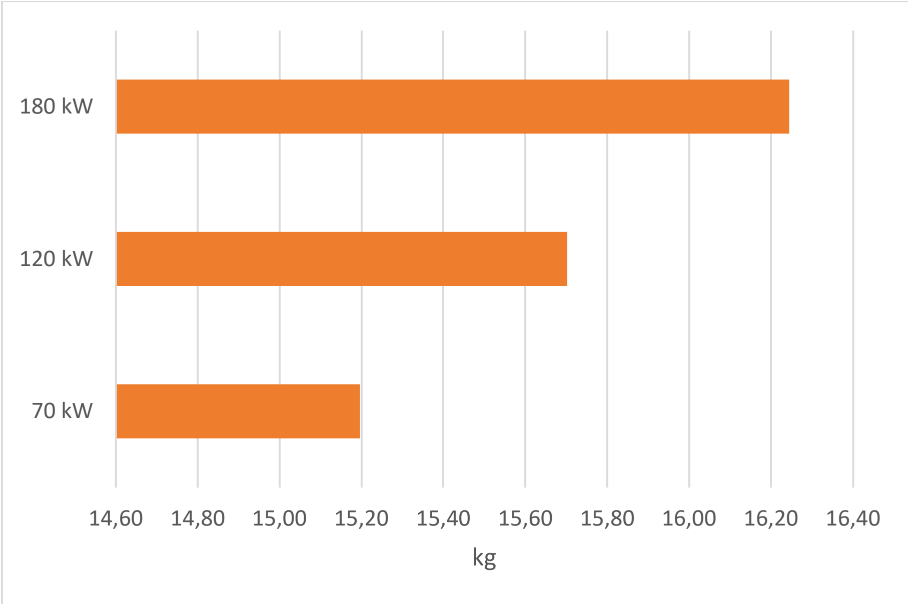

Figure 4.2 Average daily production of H_2 per electrolyzer in kg

In order to better visualize the production differences between the three electrolyzers over one year, the monthly production graph is the most compact and is shown in Figure 4.3 and 4.4 for Nm^3 and kg of hydrogen.

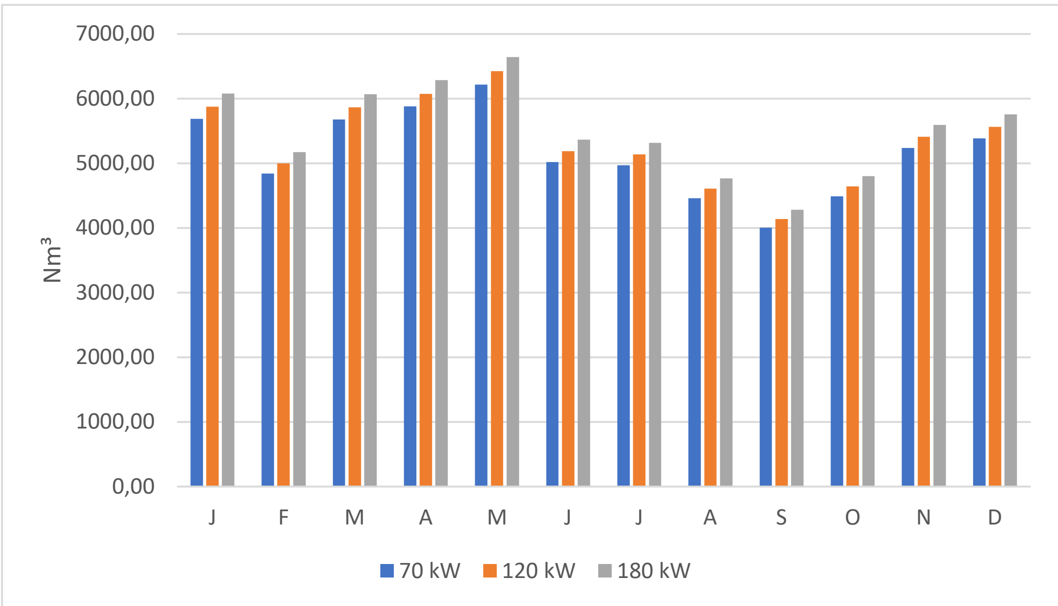

Figure 4.3 Monthly production of H_2 per electrolyzer in Nm3

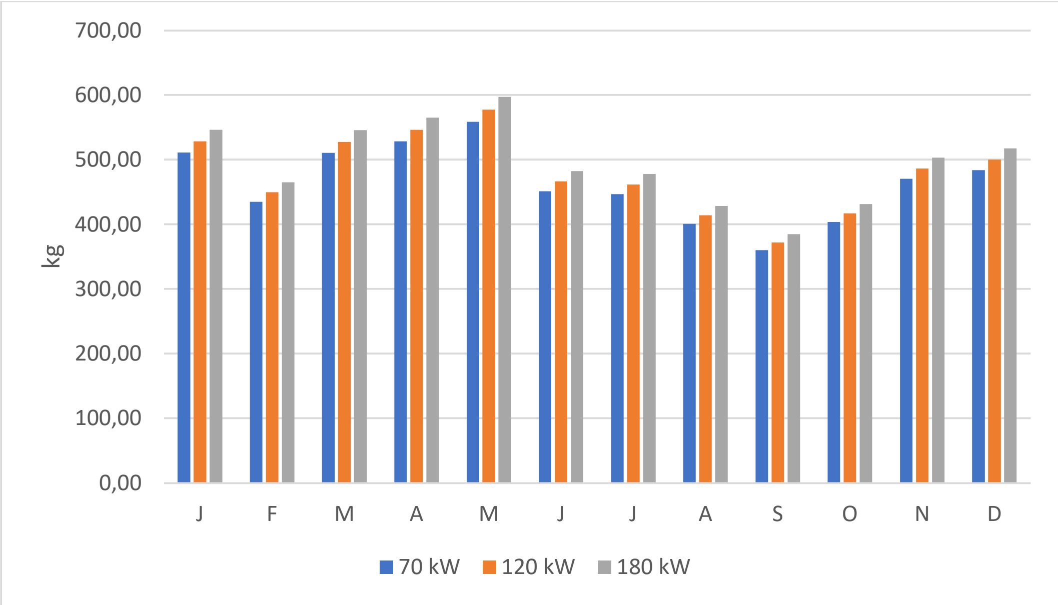

Figure 4.4 Monthly production of H_2 per electrolyzer in kg

It can be noted that the H_2 production is higher in spring than in the other seasons. This is due to the combined presence of wind and sun in those months, which brings to higher electricity production from RES. For the economic evaluation of the different plants the total yearly production data will be crucial, therefore these are summarized in Table 4.2.

	70 kW	120 kW	180 kW
Nm³H2	61,866	63,929	66,133
kg	5,562	5,747	5,945

Table 4.2 Total yearly production of H_2 per electrolyzer

4.1.2 Low-Pressure storage

The Low-Pressure storage or Bulk storage serves as a buffer between the output of the electrolyzer and the varying hydrogen demand by buses. As the hydrogen coming from the electrolyzer, the bulk storage tank is at 30 bar. This choice was made to save the electric power consumed by a pre-bulk hydrogen compressor, but in terms of footprint it will require more installation space. The principle at the basis of the choice of storage size was to exploit only the electricity produced from renewable sources, not drawing energy from the grid to produce more hydrogen. In other words, follow the hydrogen demand exploiting only the production from the previously dimensioned power plants.

Therefore, for each size of electrolyzer a calculation was made between the hydrogen produced and required so that the minimum filling of the tank is always reached with the electricity produced from the PV plant and the wind turbine. These calculations result in the suitable tank size for each electrolyzer: 336 kg (3740 Nm^3_{H2}) for 70 kW PEM, 252 kg (2800 Nm^3_{H2}) for 120 kW PEM, 207 kg (2300 Nm^3_{H2}) for 180 kW PEM.

The following charts show the State of Charge of the Low-Pressure storage in the three cases studied. It can be noted that the SOC is always higher than zero and reaches a minimum of about 0.5 ÷ 1 % in October/November. This is due to the lower production from renewables in those months that cannot follow well the accumulated demand.

Figure 4.5 SOC of the 336 kg LP storage tank for 70 kW case

Figure 4.6 SOC of the 252 kg LP storage tank for 120 kW case

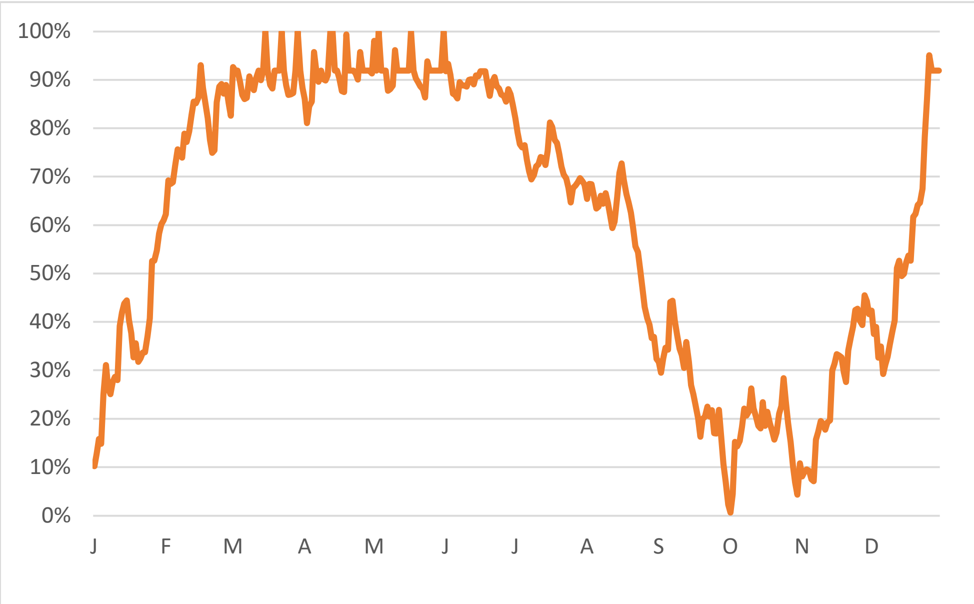

Figure 4.7 SOC of the 207 kg LP storage tank for 180 kW case

Then it is evaluated the electricity surplus upstream the hydrogen production, therefore is calculated in kWh as the electricity production that exceeds the needs of the electrolyzer to produce the hydrogen required for storage and dispensing. The economic benefit from this surplus is evaluated in chapter 5.

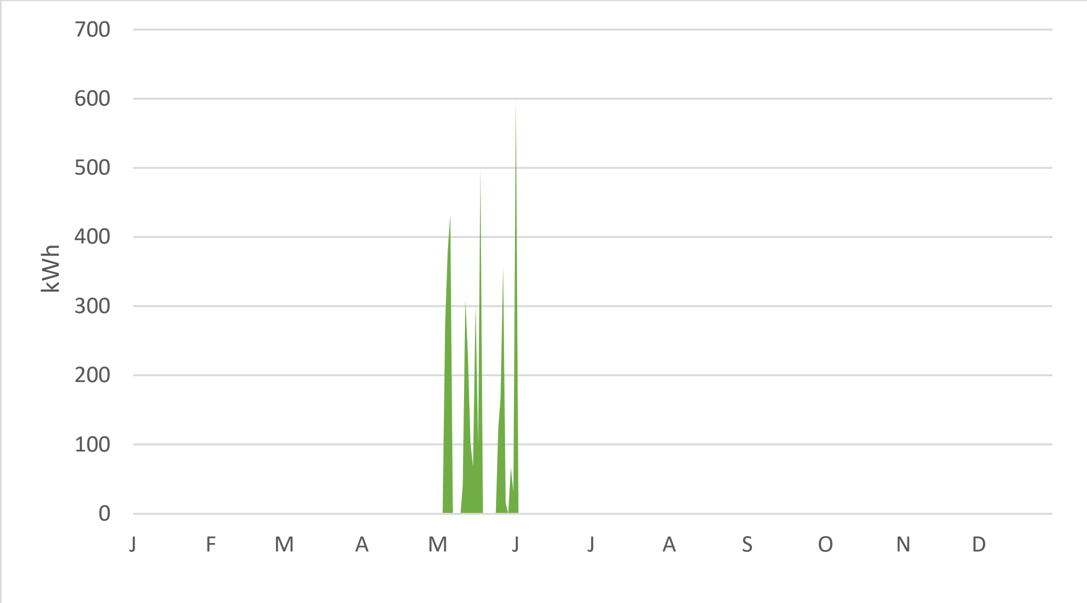

Figure 4.8 Electricity surplus in the production of hydrogen, 70 kW PEM case

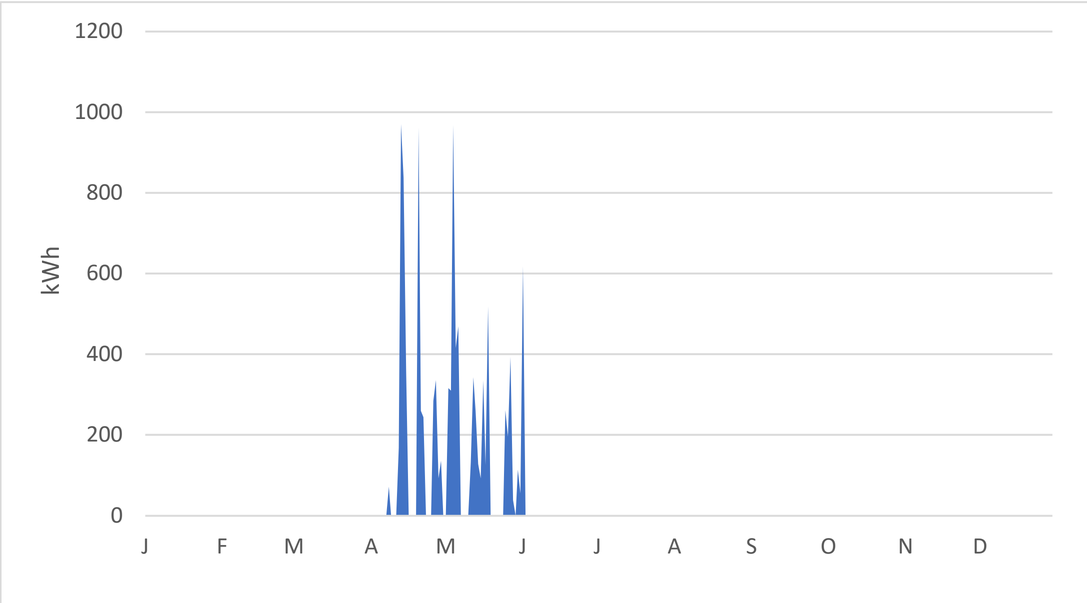

Figure 4.9 Electricity surplus in the production of hydrogen, 120 kW PEM case

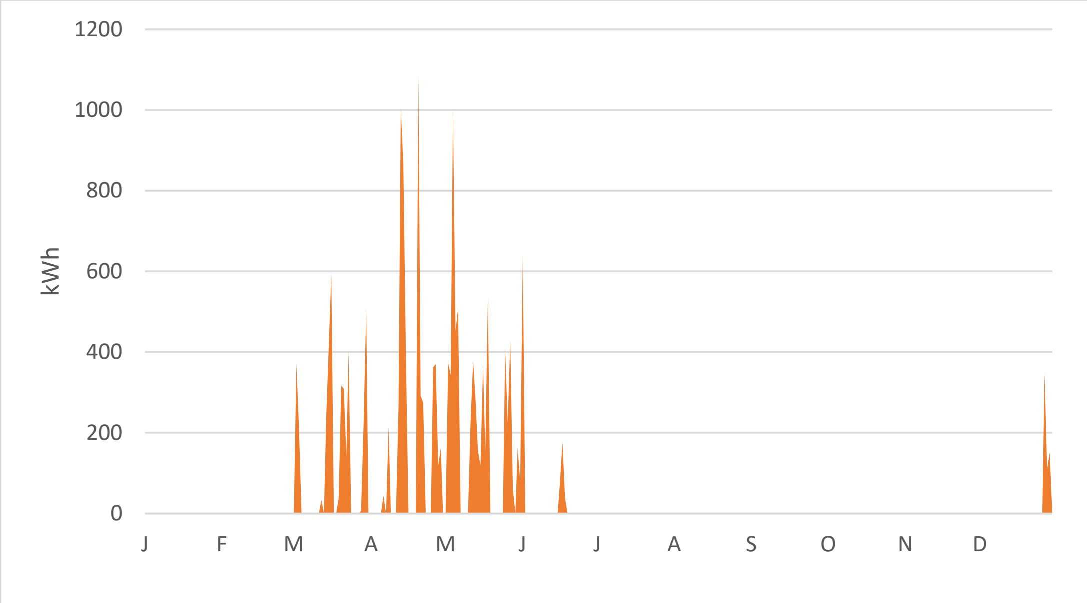

Figure 4.10 Electricity surplus in the production of hydrogen, 180 kW PEM case

4.1.3 Compression, High-Pressure storage and dispenser

After the Low-P storage the hydrogen must be compressed to enter the High-Pressure storage, named also Cascade storage, which facilitates hydrogen refueling into vehicles. The compressor must raise the pressure from 30 to 500 bar, which is the pressure chosen for the HP storage.

The sizing of the compressor is performed with a formula which calculate the power of the compressor:

$$P = Q \cdot \frac{ZTR}{M_{H_2} \cdot \eta_{comp}} \cdot \frac{N_\gamma}{\gamma - 1} \cdot \left[\left(\frac{P_{out}}{P_{in}} \right)^{\frac{\gamma - 1}{N_\gamma}} - 1 \right]$$

- Q is the flowrate in kg/s
- Z the hydrogen compressibility factor: set at 1 as an approximation
- T the temperature at the inlet of the compressor: set at 278 K
- R the ideal gas constant: equal to 8.314 J/K*mol
- M_{H2} the molecular mass of hydrogen: equal to 2.016 g/mol
- η the compressor efficiency, chosen at 75 %
- N the number of compressor stages: 3 in these cases
- γ the diatomic constant factor: equal to 1.4

- P_{in} the inlet pressure of the compressor: 30 bar
- P_{out} the outlet pressure of the compressor: 500 bar

The power of the compressors in the three cases is 1.2 kW for the 70 kW electrolyzer, 2.5 kW for the 120 kW and 3.7 kW for 180 kW.

The underlying principle of the sizing of Cascade storage is the matching of the daily demand of hydrogen. Was chosen to size the tanks taking in consideration the highest daily demand of the year which is of 17.1 kg and round it up at 18 kg (200 Nm^3_{H2}). The size is the same for all the cases since the demand of the hydrogen is the same.

Since the fuel tank of the Dolomitech's buses is at 350 bar, the hydrogen is dispensed with a proper dispenser at 350 bar. It is conceivable that the buses will be refueled or in the evening at the end of the travels or in the morning before starting them in what will be the parking lot/refueling station of the National Park. The refueling time is around 10-15 minutes per bus, therefore about half an hour is required to refill the entire fleet with only one dispenser.

4.2 Electricity storage and dispensing

As for the hydrogen, the process chain of the electric mobility infrastructure was described in the first chapter in Figure 1.3, and it is summarized again below [37].

1) The electricity is produced from the photovoltaic and wind power plants
2) Stored in Lithium-ion batteries
3) Dispensed in the Rampini E60 buses

In the hydrogen infrastructure, the analysis was focused mainly on the electrolyzers - considering three sizes - and then on the LP storage. This time, since between the production and dispensing of electricity there are only the batteries, the size's analysis is focused on the batteries [38-40].

4.2.1 Batteries and dispenser

To perform a realistic analysis, the batteries selected are commercially deployed. These are the Samsung E3-R203 of the Li-ion type [41]. One module has a capacity of 203 kWh.

The three cases of battery system's size under study are differentiated in the number of modules connected and the percentage of maximum daily demand of electricity (600.4 kWh) covered:

1) 609 kWh: three modules to cover 99.77% of the maximum daily demand of electricity
2) 812 kWh: four modules to cover 133% of the maximum daily demand of electricity
3) 1,015 kWh: five modules to cover the 166.3% of the maximum daily demand of electricity

Now the State of Charge of the battery system with these capacities can be evaluated, taking in consideration a crucial characteristic of the electrochemical storage systems. In fact, to preserve the integrity of the battery, the SOC has been considered always higher than 10% and lower than 90%. With these precautions will be guaranteed to the batteries a longer life and a low deterioration for an efficiency as constant as possible over the years.

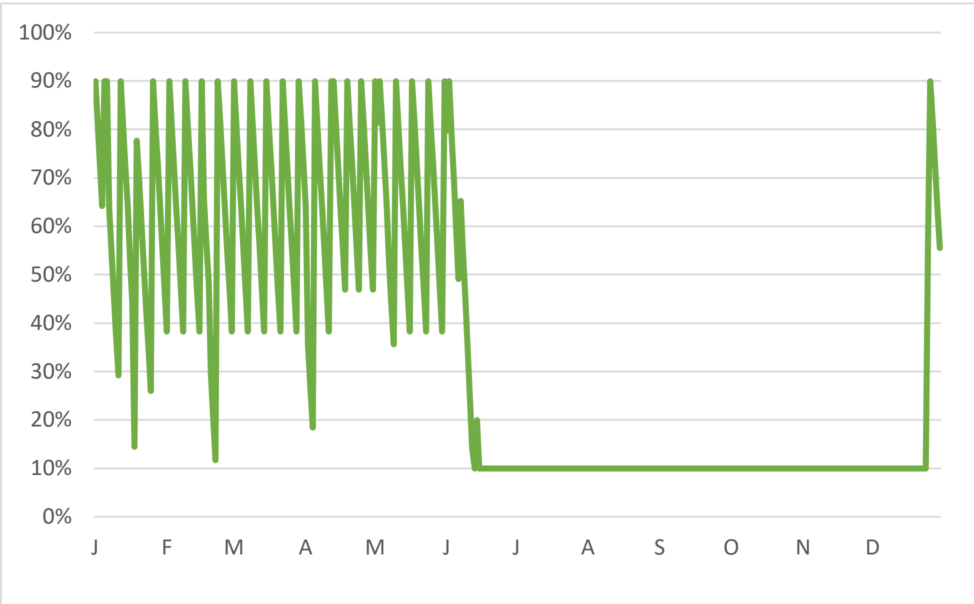

Figure 4.11 SOC of the 609 kWh Li-ion battery

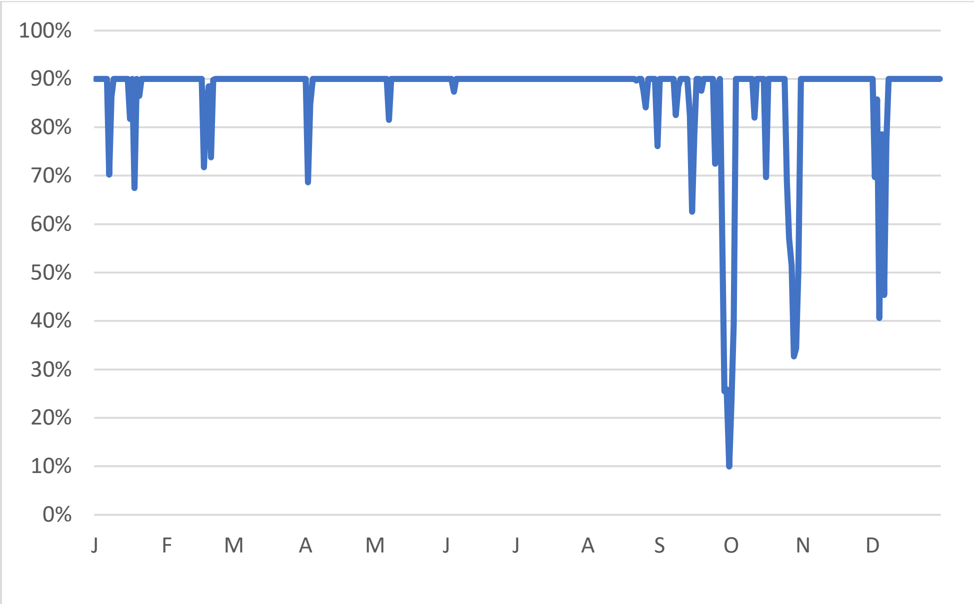

Figure 4.12 SOC of the 812 kWh Li-ion battery

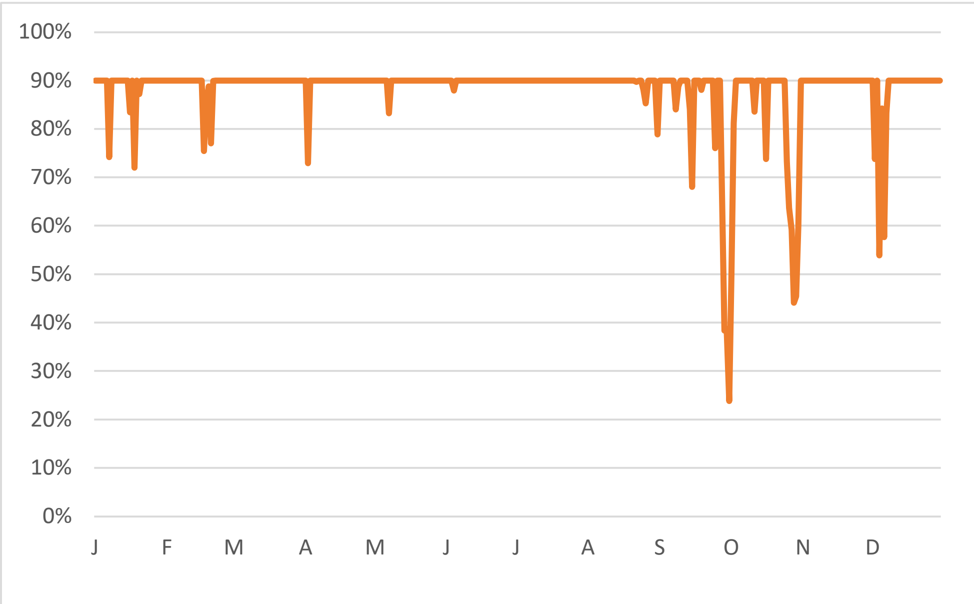

Figure 4.13 SOC of the 1015 kWh Li-ion battery

In Figure 4.12 and 4.13 can be noted that, like for the hydrogen case, the most demanding months are October and November. But for what concerns the first case, the capacity value of 609 kWh does not guarantee an adequate coverage of demand, from June to December, with the electricity produced only by the two renewable plants; therefore, the electricity needed by the buses in these months should be purchased. But, since the idea is to never rely on the electricity network, this case is the worst and should be discarded.

As made in the hydrogen case, the surplus/deficit is evaluated in kWh as the electricity production that exceeds the needs of the battery and buses or the electricity missing to match the demand of the public transport. The economic value from this surplus or deficit is evaluated in the next chapter.

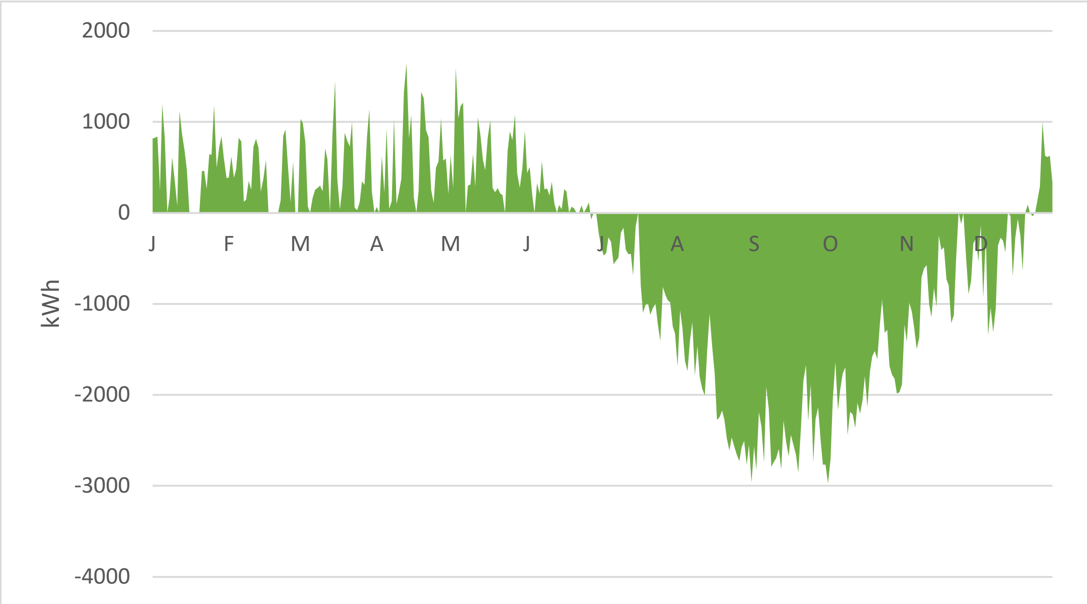

Figure 4.14 Electricity surplus/deficit in the case of a 609 kWh battery

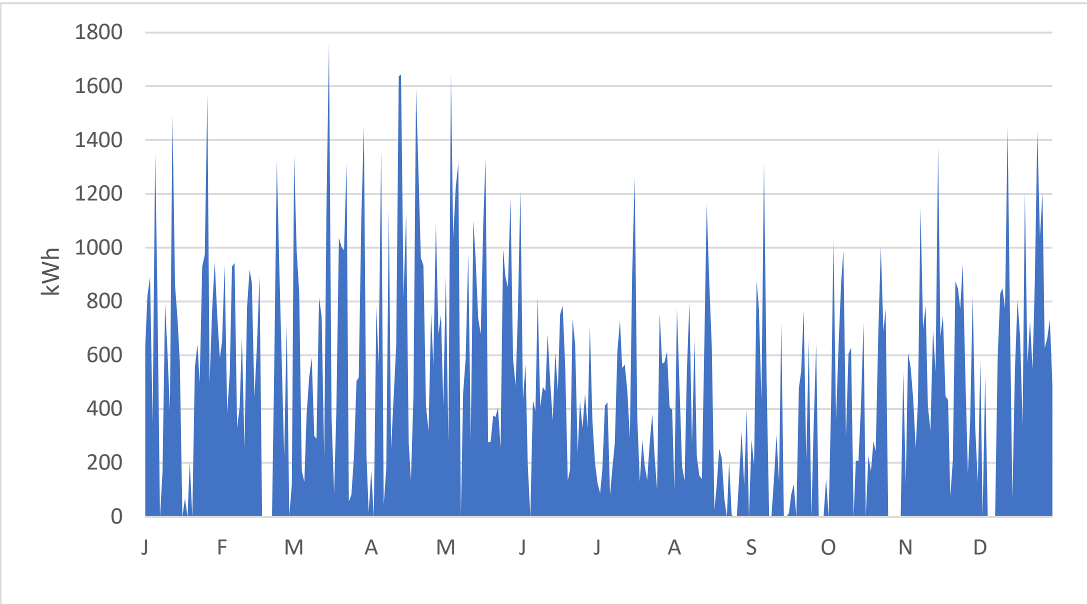

Figure 4.15 Electricity surplus in the case of an 812 kWh battery

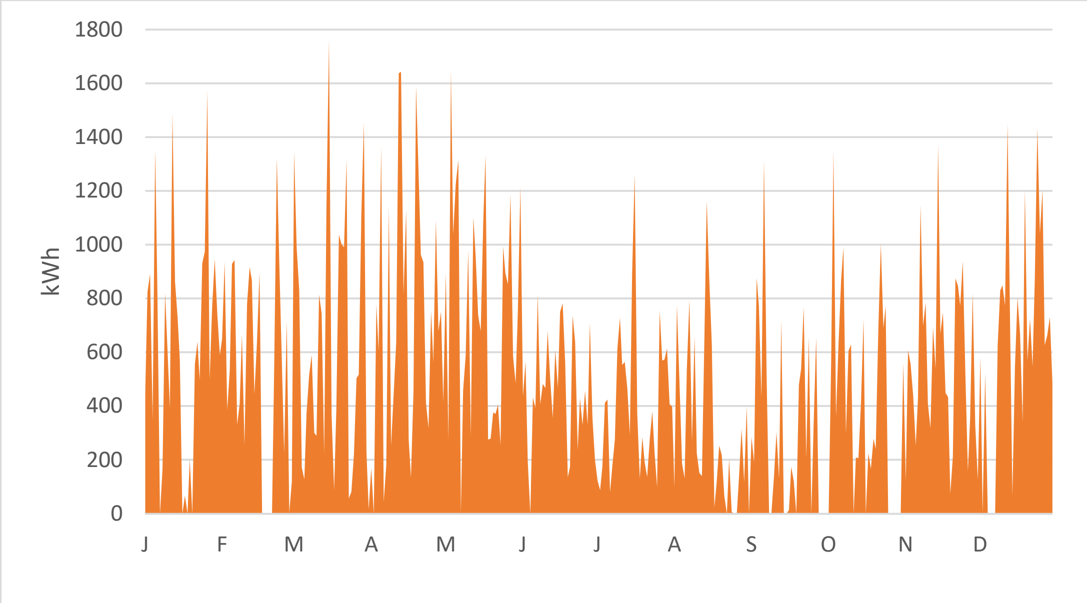

Figure 4.16 Electricity surplus in the case of a 1015 kWh battery

Unlike the hydrogen infrastructure in which only one dispenser was hypothesized, for the electrical case two sequential 150 kW dispensers with three recharge boxes to be attached to three buses are assumed to be installed. This is due to the electricity refueling which takes much longer than the faster hydrogen refueling [43].

In order to save as much time as possible, it has been assumed to use two sequential dispensers, i.e., one dispenser has the possibility of being simultaneously connected to three buses, when the first bus is fully charged the recharging of the second bus will automatically start and so on. This is a commercial technology by ABB [42].

Having a fleet of 7 buses and assuming a full charge duration of 1.5 hours for one bus, the entire fleet can be recharged in 6 hours: six buses simultaneously with two dispensers for a total of 4.5 hours and one bus thereafter for a duration of 1.5 hours.

5. Techno-economic evaluation

In this chapter, the economic feasibility of the two infrastructures is analyzed. The costs of each component are assessed with also the cashflows and the Levelized Costs for each of the six cases.

The two types of Levelized Costs, LCOH for the hydrogen infrastructure and the LCOEV for the electric case are calculated by means of the Cost Estimation Methodology by NETL [44].

5.1 Economics of the hydrogen infrastructure

The costs of the components of the hydrogen mobility plant are evaluated through various price data taken from several publications which then, by means of specific cost functions, are related to the power and capacity data of the components used in this thesis [26][27][45].

For what concerns the PEM electrolyzers, the LP and HP storage tanks, the cost function used is the following:

$$CAPEX\left[\frac{€}{kW}\right] = C_{ref} \cdot S_{ref} \cdot \left(\frac{S_{real}}{S_{ref}}\right)^{\frac{coeff}{S_{real}}}$$

Where C_{ref} is the reference capital cost, 1,285.2 €/kW for electrolyzers, while 55.7 €/Nm³ for storage tanks; S_{ref} is the reference capacity, 9,096.2 kW for electrolyzers, while 5,526.2 Nm³ for tanks; the coefficients are 0.89 for the electrolyzers and 0.77 for the storage tanks.

Therefore, replacing S_{real} with the power sizes of the three electrolyzers and the capacities of the LP and HP storage tanks, their CAPEX will be calculated.

PEM Electrolyzers:

- 70 kW: CAPEX = 2,208.5 €/kW, C_{tot} = € 154,598
- 120 kW: CAPEX = 2,080 €/kW, C_{tot} = € 249,601
- 180 kW: CAPEX = 1,988.3 €/kW, C_{tot} = € 357,888.6

Low-Pressure storage tanks:

- 336 kg (3740 Nm³): CAPEX = 61 €/ Nm³, C_{tot} = € 227,785
- 252 kg (2800 Nm³): CAPEX = 66 €/ Nm³, C_{tot} = € 182,284
- 207 kg (2300 Nm³): CAPEX = 68 €/Nm³, Ctot = € 156,669

High-Pressure storage tanks:

- 18 kg (200 Nm³): CAPEX = 119.5 €/Nm³, Ctot = € 23,922.8

The yearly OPEX for the electrolyzers are assumed to be the 4% of the CAPEX, while for the storage tanks are the 2% of the CAPEX.

The cost of the compressors is evaluated in a different way, by means of the following formula:

$$CAPEX_{compressor}[€] = 15{,}000 \cdot \left(\frac{S_x}{10\ kW}\right)^{0.9}$$

The cost of a reference 10 kW compressor is € 15,000; therefore, replacing S_x with the capacities of the compressors, their capital costs will be calculated.

- 1.2 kW compressor: CAPEX = € 2,278
- 3.3 kW compressor: CAPEX = € 4,250.5
- 5 kW compressor: CAPEX = € 6,122.5

Finally, the cost of a dispenser is assumed to be around € 30,000. This value comes out of an average of those found in literature. The yearly OPEX for both compressors and dispensers are the 2% of the CAPEX.

The total investment costs are then evaluated following the NETL's Cost Estimation Methodology, where in addition to the CAPEX of the components, other "overnight costs" are considered in the total investment:

- BEC: Bare Erected Cost (process equipment, supporting facilities, direct and indirect labor), it is the 20% of the CAPEX
- EPCC: Engineering, Procurement and Construction Cost (EPC contractor services), it is the 8% of the BEC

- TPC: Total Plant Cost (process and project contingencies). The TPC process is the 5% of the BEC and then the TPC project is the 7% of the EPCC plus the TPC process
- TOC: Total Overnight Cost (pre-production costs, inventory capital, financing costs and other owner's costs). Finally, the TOC is the 15% of the sum of EPCC and TPC (process and project)

The total initial investment costs are then: € 731,802 for the 70 kW case, about € 817,691 for the 120 kW, € 958,758 for the 180 kW.

For what concerns the OPEXs, to the fixed ones of the component, are added the variable O&M costs which include the water's purchase for the electrolyzers and the catalyst/chemical consumption. The latter is considered the same for each case and is around € 2,000 per year, while the purchase of water varies from case to case, but it does not exceed 100 € and, therefore, the $OPEX_{var}$ are around € 2,000 – 2,100; summing them to the fixed ones, the total O&M costs are about € 13,900 for the 70 kW electrolyzer, € 16,860 for the 120 kW, € 20,750 for the third case.

Before calculating the LCOH and the cashflows in the three cases, it has been evaluated if and how many times the components should be replaced, and the related costs of these replacements spread over the entire lifetime of the infrastructure. Considering the cost of each replacement as the 35% of the CAPEX, to spread it over the entire lifetime, knowing that the useful life of the PEM is 40,000 hours and calculating the yearly working hours of the three cases, the number of replacements is evaluated [46].

- 70 kW case: the yearly hours of operation are about 6200, it should be replaced every 7 years and therefore, considering the lifetime of 20 years, the number of replacements is about 3. Spreading the costs, 5% of the initial investment is paid every year.
- 120 kW: 3200 yearly working hours, a replacement every 13 years, about 1.5 replacements in 20 years, this value is not rounded to precisely calculate the yearly costs, which are the 2.7% of the initial investment.
- 180 kW: 2200 yearly working hours, a replacement every 19 years, about 1 in 20 years. The yearly replacement costs are the 1.8% of the initial investment.

The next chart shows the investment costs composition where can be noted the relevance of the electrolyzer, the bulk storage and the plant costs. The electrolyzer/storage ratio increase with the size of electrolyzer, that is because the cost per unit is higher for the electrolyzer than for the storage.

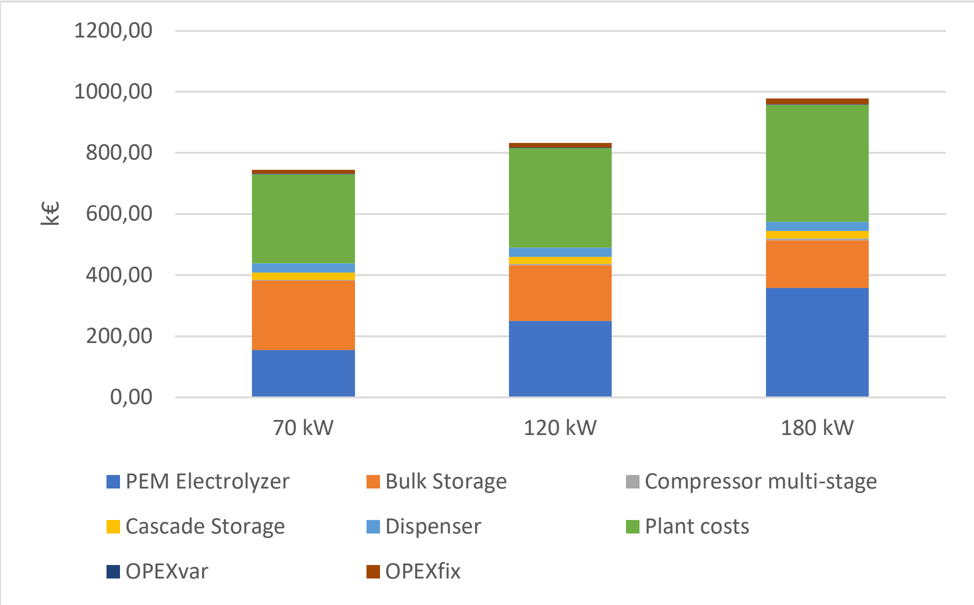

Figure 5.1 Costs composition in the three hydrogen mobility cases

5.1.1 LCOH calculation

As said before, the Levelized Cost of Hydrogen is calculated following the methodology proposed by NETL [44]. The procedure is divided into two steps:

1) The calculation of the Cost of Hydrogen, which is the revenue received by the generator per net kilogram during the plant's first year of operation, assuming that the COH escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the plant [44].

$$COH = \frac{(CCF)(TOC) + OPEX_{fix} + (CF)(OPEX_{var})}{(CF)(kg)}$$

Where:

- CCF = Capital Charge Factor that matches the applicable finance structure and capital expenditure period. In this case considering a High-Risk IOU Finance Structure and a Capital Expenditure Period of three years, the CCF is equal to 0.111.

- TOC = Total Overnight Cost
- $OPEX_{fix}$ = the sum of all fixed operation costs
- $OPEX_{var}$ = the sum of all variable operation costs
- CF = plant capacity factor, expressed as a fraction of the total hydrogen that would be generated if the plant operated at full load without interruption.
- kg = annual net kilogram of hydrogen generated at 100% capacity factor

2) The calculation of the Levelized Cost of Hydrogen is the revenue received by the generator per net kilogram during the plant's first year of operation, assuming that the COH escalates thereafter at a nominal annual rate of 0%, i.e., that it remains constant in nominal terms over the operational period of the plant [44]. Therefore, multiplying the COH by a levelization factor LF.

$$LCOH = LF \cdot COH$$

$$LF = \frac{A \cdot (1 - K^{LP})}{(D - N)}$$

With:

$$K = \frac{1 + N}{1 + D}$$

$$A = \frac{D \cdot (1 + D)^{LP}}{(1 + D)^{LP} - 1}$$

Where:

- LP = levelization period, 20 years
- D = discount rate = 4%
- N = nominal escalation rate → N = R + I (R = real escalation rate, I = inflation rate)

The inflation rate is assumed to be at 2% and the real escalation rate at 4%.

The calculations, made for each case, give us the results shown in Figure 5.2.

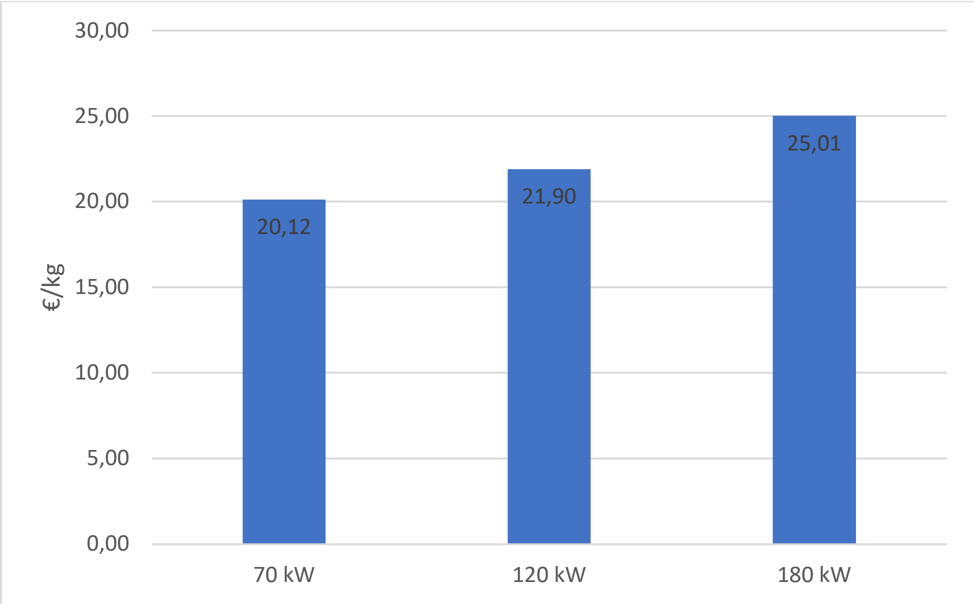

Figure 5.2 LCOH in the three cases

The cashflows can now be calculated, taking in consideration the initial investment, the electricity sold and purchased, the O&M costs, the incomes, the replacement costs spread over 20 years and a yearly insurance assumed to be the 1% of the initial investment.

The electricity prices are taken from two diverse sources:

- The price of the electricity sold is taken from [47]. For Pantelleria this is 0.144 €/kWh.
- The price of the electricity purchased is the average of the Italian electricity's price at 31/12/2020 and 31/12/2021 taken from the IEA electricity prices database [48]. The result is 0.108 €/kWh.

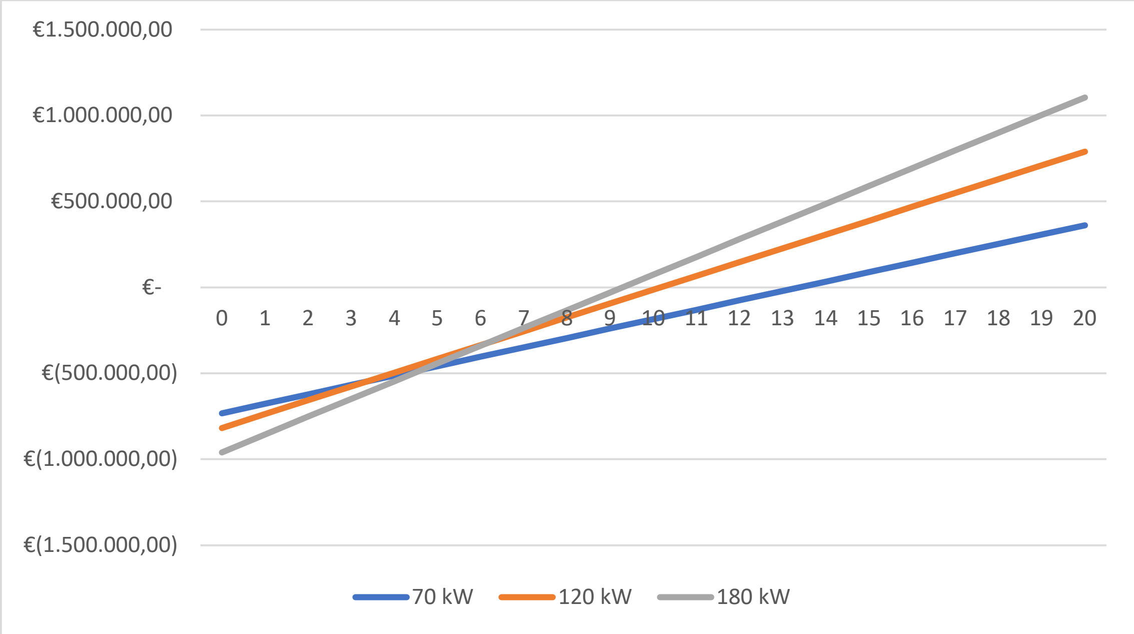

Figure 5.3 Cashflows of the hydrogen infrastructures

From Figure 5.3 can be seen that the Pay Back Times are different in the three cases: 13 years and 5 months in the 70 kW case, 10 years and 2 months in the 120 kW case and 9 years and 3 months in the 180 kW case. Therefore, increasing the size of electrolyzer and storage tank, the economic profitability will increase but with higher investment, higher annual costs and less competitiveness in terms of LCOH.

5.2 Economics of the electric infrastructure

Given the smaller number of components, the electrical case is simpler and faster to analyze. The costs to be defined are those of batteries and chargers, but unlike the components of the hydrogen infrastructure, their costs are not calculated by means of formulas, but directly taken from sources: the cost of batteries is 300 €/kWh [49] and the cost of a 150 kW charger is € 75,000 [50], which since in this study is assumed that two chargers of the same type will be installed, the total cost is € 150,000. Therefore, considering the size of batteries in the three cases studied, the prices of batteries can be calculated:

- 609 kWh → € 182,700
- 812 kWh → € 243,600
- 1,015 kWh → € 304,500

The yearly fixed OPEX are the same for both components and are assumed to be the 2% of the CAPEX. The variable O&M were hypothesized to be the 20% of the fixed ones.

The total initial investment costs are then evaluated following, like in the hydrogen case, the NETL's Cost Estimation Methodology [44]. The results in the three cases are:

- 609 kWh: € 555,130
- 812 kWh: € 656,745
- 1,015 kWh: € 758,360

The sum of fixed and variable OPEX are respectively € 7,985, € 9,450, € 10,908.

For the electric infrastructure, the replacement of components was assumed to happens only one time in 20 years and that it will costs 50% of the initial investment. Spread it over the entire lifetime it will costs 2.5% of the initial investment per year.

In Figure 5.4 the investment costs composition is shown for the three cases where can be noted the relevance of the battery's price.

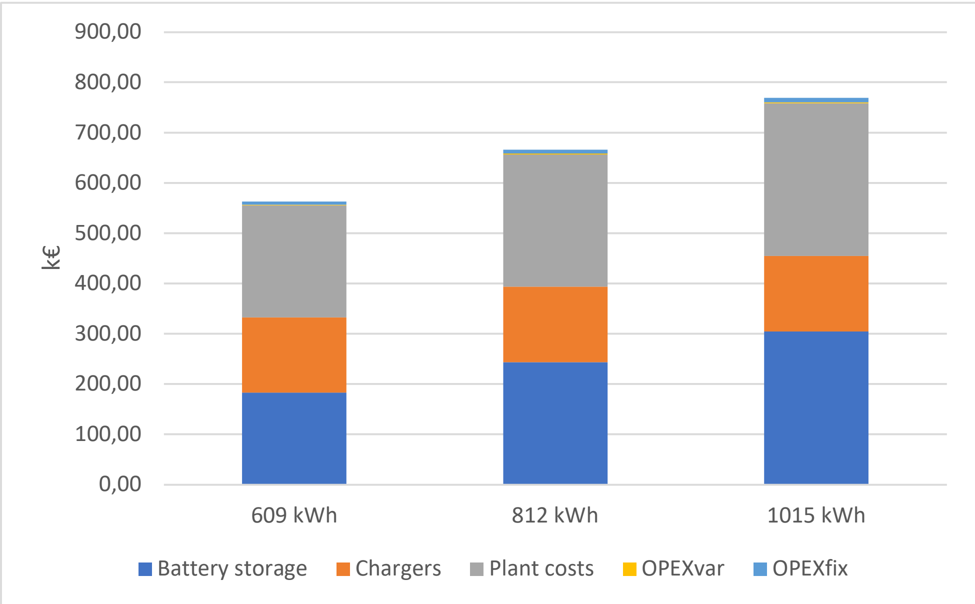

Figure 5.4 Costs composition in the three electric mobility cases

5.2.1 LCOEV calculation

The evaluation of the Levelized Cost in the electric case follows again the NETL methodology, but this time the Cost of Electric Vehicles and the Levelized Cost of

Electric Vehicles are expressed in €/kWh [44]. The economic parameters remain the same and therefore the major changes are in the TOC, the OPEXs and the Capacity Factor expressed as a fraction of the total electricity that would be generated if the plants operated at full load without interruption and the annual net kilowatt-hours of electricity generated at 100% capacity factor. The results for the calculated LCOEV are in Figure 5.5.

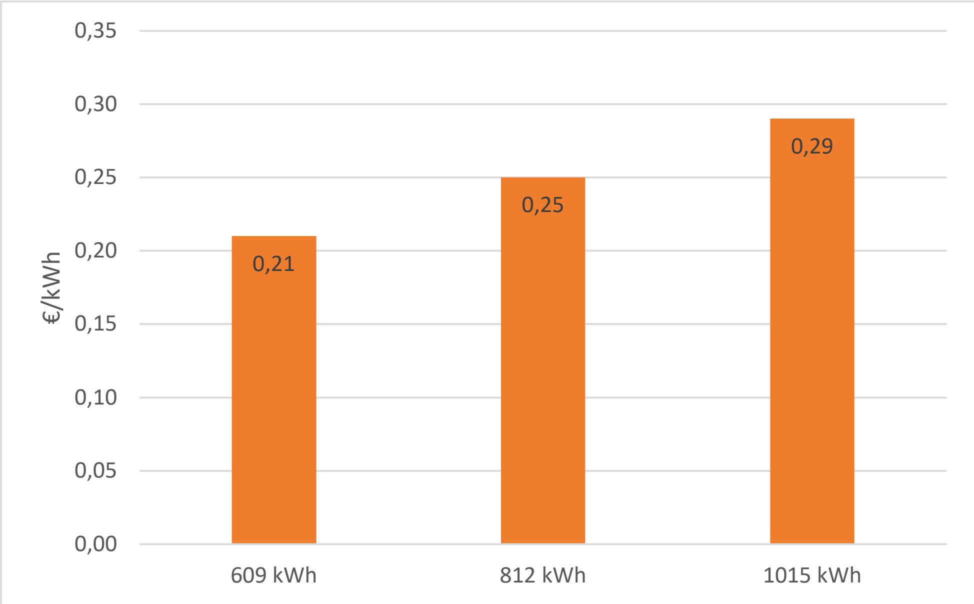

Figure 5.5 LCOEV in the three cases

The cashflows can now be evaluated considering, like in the hydrogen's case, the initial investment, the electricity sold and purchased, the O&M costs, the incomes, the replacement costs spread over 20 years and a yearly insurance assumed to be the 1% of the initial investment. The electricity prices are the same as before 0.144 €/kWh for the electricity sold and 0.108 €/kWh for the electricity purchased [47][48].

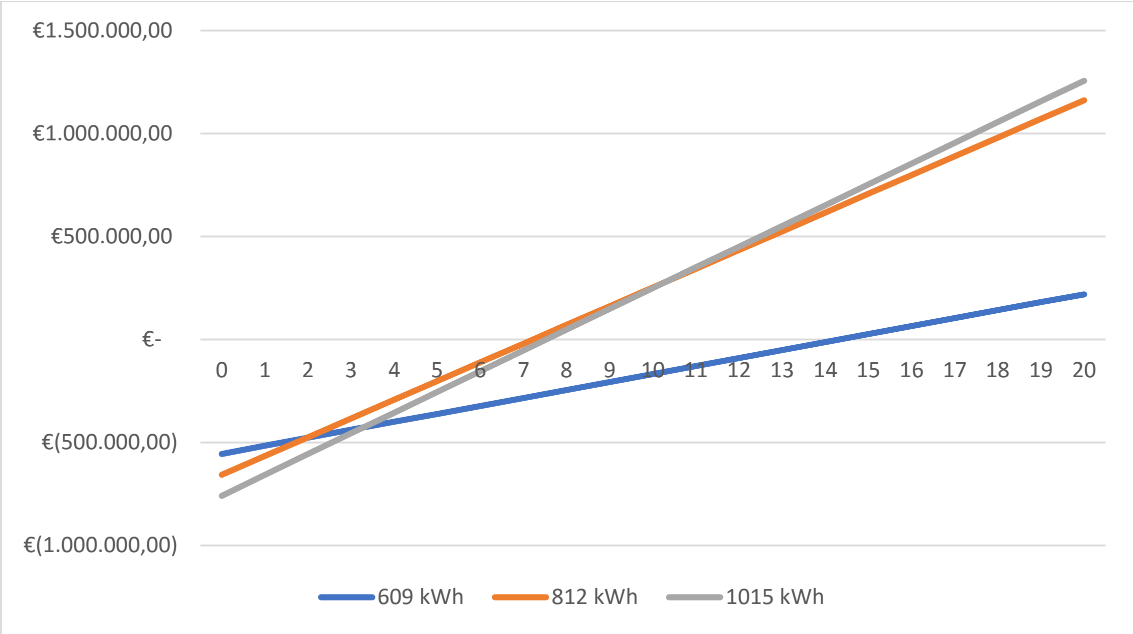

Figure 5.6 Cashflows of the electric infrastructure

The PBT is respectively 14 years and 4 months, 7 years and 3 months, 7 years and 6 months. The case with a 609 kWh battery is the worst because of the need to purchase the electricity from the grid, while the other two are very similar to each other. The 1,015 kWh case is more expensive than the 812 kWh case but more profitable at the end of 20 years.

In the next chapter is optimized the sizing of the two infrastructures, with also the evaluation of the total cost of the project in the two cases, considering both the costs of the two renewable plants and the costs of the buses.

6. Sizing and costs optimization

The purpose of this last chapter is to find the optimal configuration in the two cases, following both a technical and an economic criterion. In a nutshell, dimensioning the infrastructure components (electrolyzer and LP tank on the hydrogen side, battery on the electrical side) in order to perfectly satisfy the demand of the buses by exploiting only the photovoltaic and wind power plant, but at the same time minimizing investment costs.

This techno-economic optimization work was carried out through the use of PyPSA, an open-source toolbox for simulating and optimizing modern power systems that include features such as conventional generators with unit commitment, variable wind and solar generation, storage units, coupling to other energy sectors, and mixed alternating and direct current networks [51].

Two simulation/optimization codes were then written on PyPSA. These created models work like networks, with a central node to which the various components are connected. Considering that nationwide networks can be modeled with PyPSA the components can be of many types, but the models created in this case are very simple and therefore were used only two generators (PV and Wind power plant), a storage (LP tank in one case, battery in the other) connected to a storage node and a load (demand of buses). Important components are the links which connect the storage with the central node. For the hydrogen case they are the electrolyzer which "recharge" the storage unit and the compressor which "discharge" it, while for the electric case they are simply a recharge and a discharge link. Every component is technically and economically characterized and some useful parameters to be set are capital costs, nominal power, and efficiency. The technical and then economic results of the optimized infrastructures are explained in detail in the next paragraphs.

6.1 Optimized hydrogen mobility infrastructure

The before-mentioned network for the hydrogen case is presented in Figure 6.1. Remembering that the purpose for the hydrogen case was to find the optimal size of both the electrolyzer and bulk storage tank, following the optimization criteria of PyPSA, the results are that the first should be of 100 kW and the second of 306 kg (3400 Nm^3). Being these values similar to the ones hypothesized previously, these results can be considered really valuable.

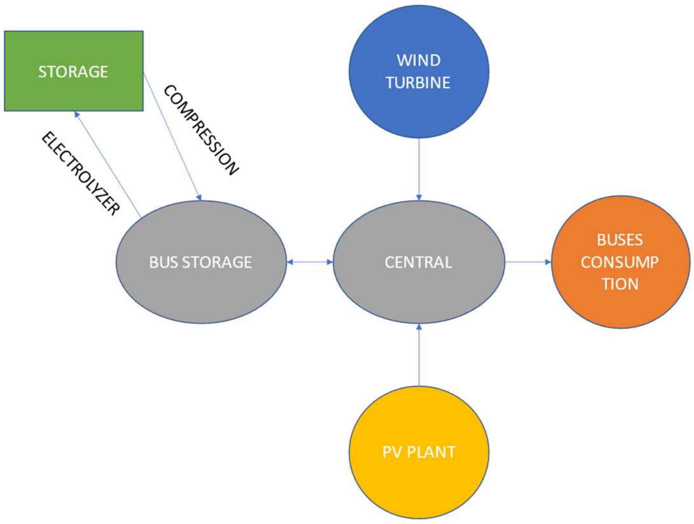

Figure 6.1 Hydrogen mobility infrastructure on PyPSA

With the optimal values of sizes just found, the production, storage and dispensing of hydrogen is again studied and compared with the results from PyPSA.

Assuming that the characteristics of the 100 kW electrolyzer are an average between those of the 70 kW and 120 kW (i.e., efficiency 58%, energy consumption of about 68 kWh/kg), the average daily production (Figure 6.2) and the monthly production (Figure 6.3) charts are shown with the addition of the results for the optimal electrolyser.

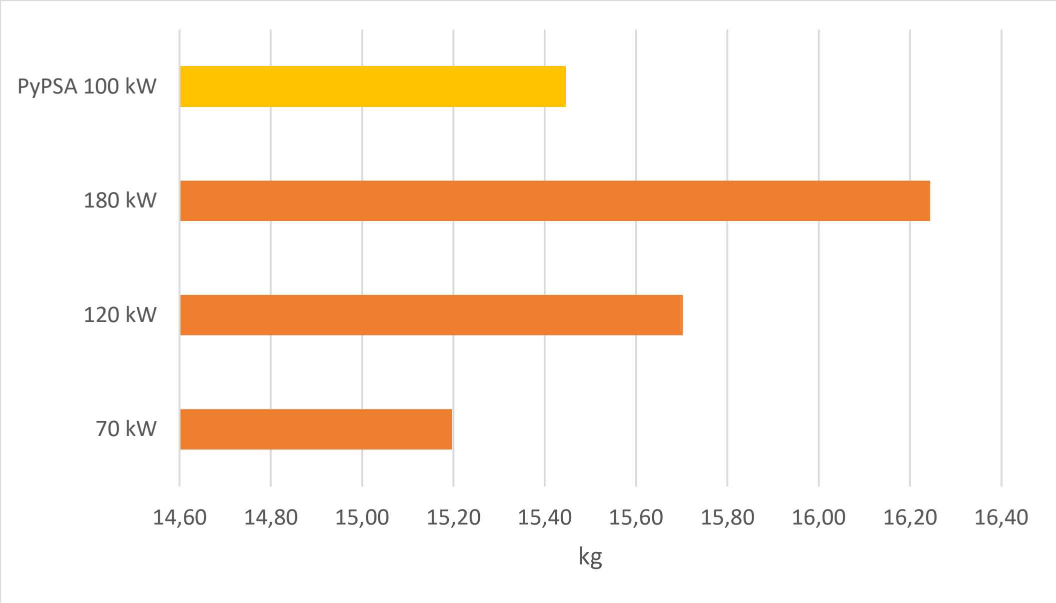

Figure 6.2 Average daily production of hydrogen in all four cases

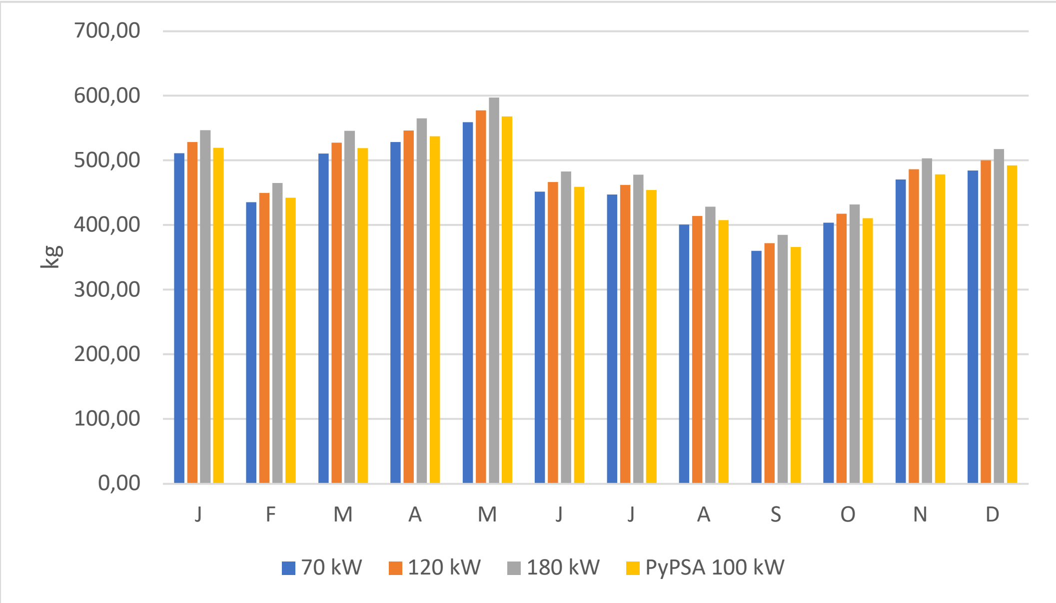

Figure 6.3 Monthly production of hydrogen in all four cases

This time was decided also to show the daily production of hydrogen for the optimal case to better visualize the production trend which follows the combined production of PV and Wind power plant.

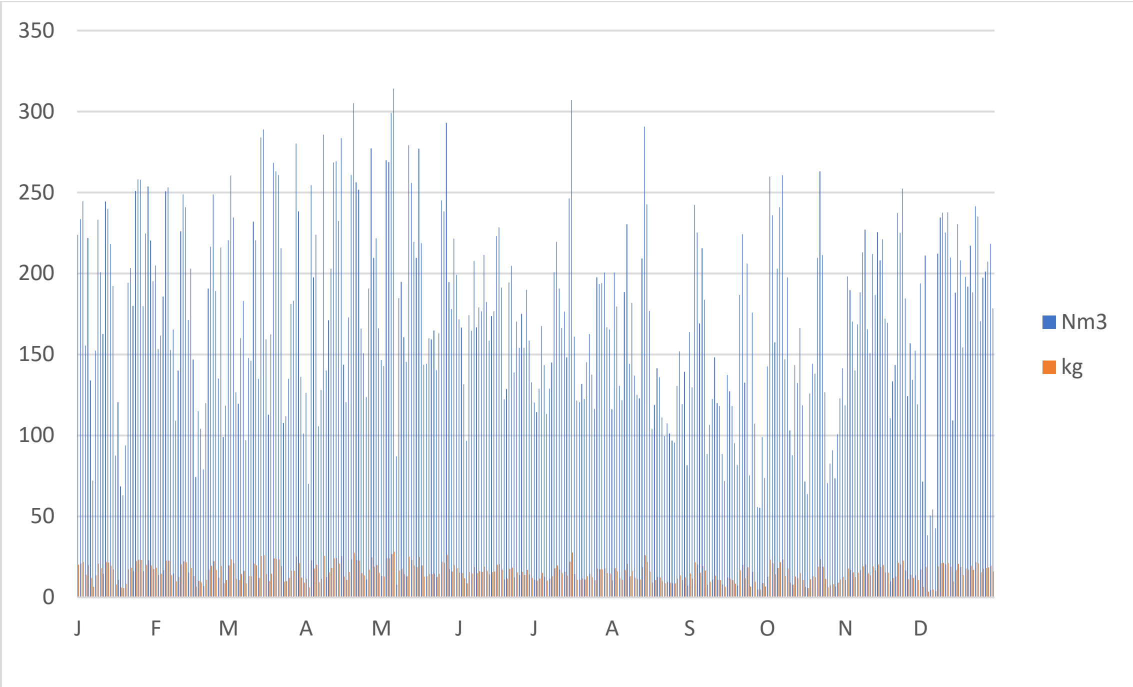

Figure 6.4 Daily production of hydrogen with 100 kW electrolyzer

The SOC of the optimal 306 kg LP storage tank is calculated (Figure 6.5) and the first thing that can be noted is that the minimum filling of the tank is always reached with the electricity production from the two RES plants and never needs the aid of the grid. Also, the surpluses of electricity are not so high, therefore it can be confirmed the validity of the values found with PyPSA.

Figure 6.5 SOC of the optimal 306 kg LP tank for the 100 kW case

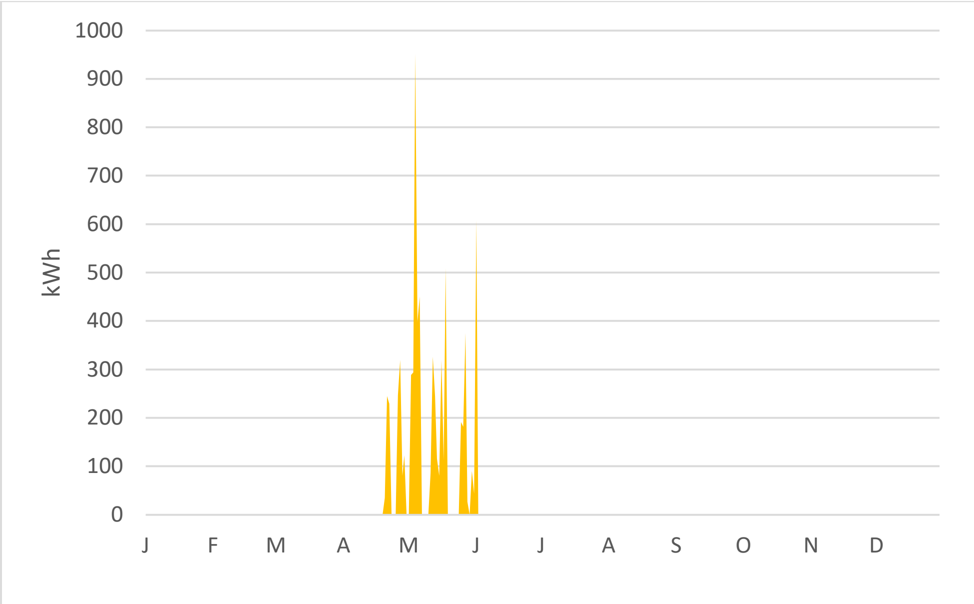

Figure 6.6 Electricity surplus in the optimal case

The suitable compressor for this case is evaluated with the formula presented in 4.1.3 for the calculation of the power size of compressors which in this case is 2.1 kW. The Cascade storage's size is the same as in the other cases since, as already explained, it is dimensioned taking in consideration the highest daily demand of hydrogen which doesn't change with the simulations. Finally, is assumed the installation of only one dispenser like in the other cases.

6.2 Optimized electric mobility infrastructure

The network for the electric case is presented in Figure 6.2. The goal for the electric case was to find the optimal capacity of the battery and the result in this case is that the battery should be of 933 kWh. Given the similarity to the previously hypothesized capacities, it can be stated that this is a valid result.

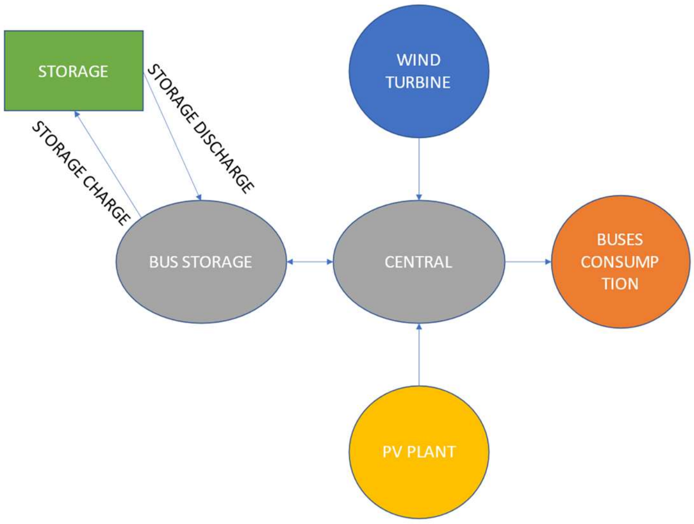

Figure 6.7 Electricity infrastructure on PyPSA

As was done for the hydrogen case, the calculations on the storage of electricity are performed with the optimal capacity and compared to the ones obtained before.

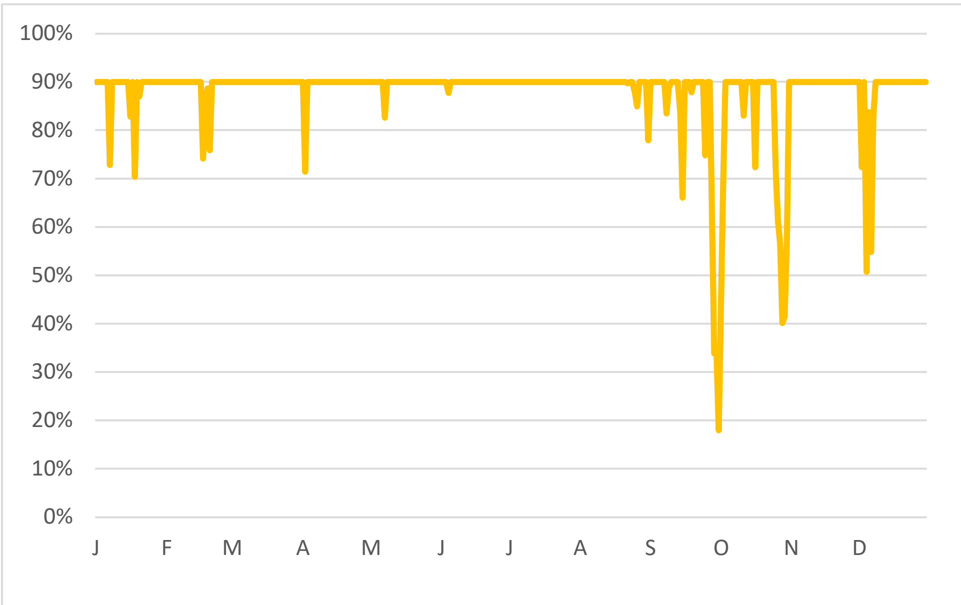

Figure 6.8 SOC of the optimal 933 kWh Li-ion battery

The State of Charge of the optimal 933 kWh Li-ion battery (Figure 6.8) confirm that the value found with PyPSA is a valid result and comparable with the others. In fact, the minimum charge of the battery is always reached without the need of the grid and the surplus is in line with the other cases (Figure 6.9).

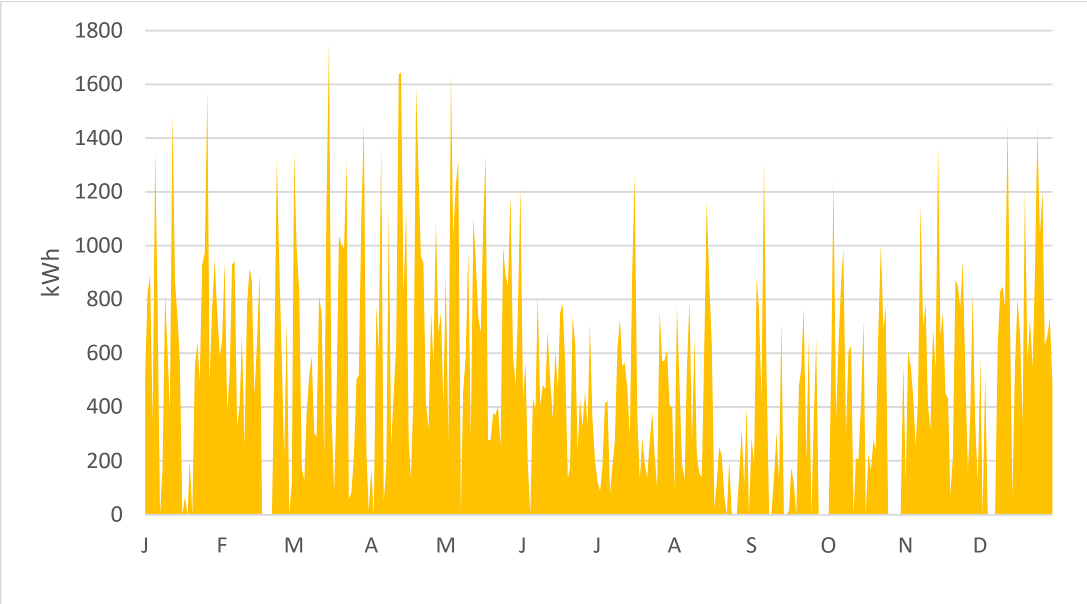

Figure 6.9 Electricity surplus in the case of a 933 kWh battery

For what concerns the dispensing side and its configuration, it is the same already presented, two sequential chargers with three connections each, to make the most of the hours of the night to recharge all the electric buses.

6.3 Techno-economic evaluation on optimized plants

This chapter deals with the economic evaluation of optimized infrastructures. As previously done in CAPEX analyses, specific cost's functions are used for each component to assess their costs, or, as in the case of the battery in the electrical infrastructure, unit costs suggested by sources consulted. The functions and unit costs used are the same, so it is only needed to replace the values found with the previous ones.

The other plant costs are evaluated following again the NETL's Cost Estimation Methodology. Remembering the composition of these overnight costs:

- BEC: 20% of the CAPEX

- EPCC: 8% of the BEC

- TPC: TPC process 5% of the BEC, TPC project 7% of the EPCC plus the TPC process

- TOC: 15% of the sum of EPCC and TPC (process and project)

By carrying out all the appropriate calculations, the results on the total costs of the optimal plants are achieved, which as shown in Figures 6.10 for the hydrogen case and Figure 6.11 for the electric case are in line with the previous ones. In fact, considering their role of configurations that optimize performances minimizing costs, it is for this reason that they rank below the most expensive cases and clearly above the cheapest, finding a compromise between technical characteristics and economic feasibility.

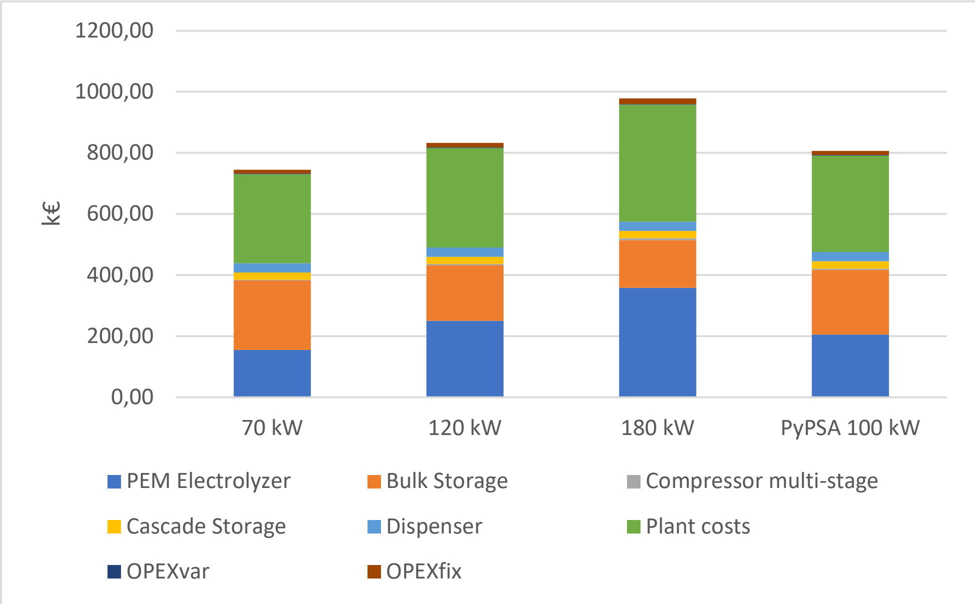

Figure 6.10 Costs composition in all four hydrogen cases

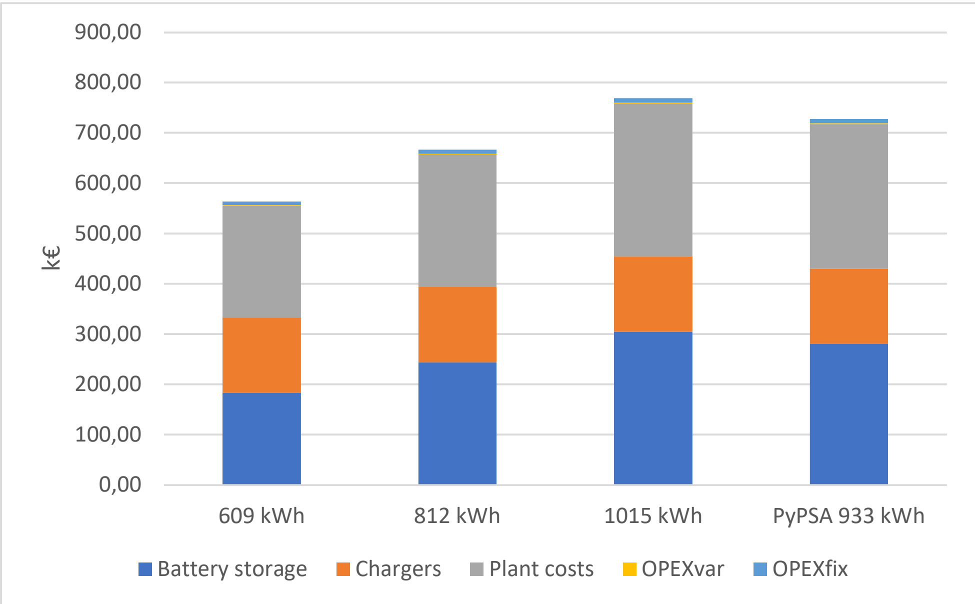

Figure 6.11 Costs composition in all four electric cases

For what concerns the Levelized Costs of the two technologies, they are calculated with the NETL's methodology as done before for the other cases. The economic parameters are the same as those used previously. The results are shown in Figure 6.12 for the LCOH and Figure 6.13 for the LCOEV.

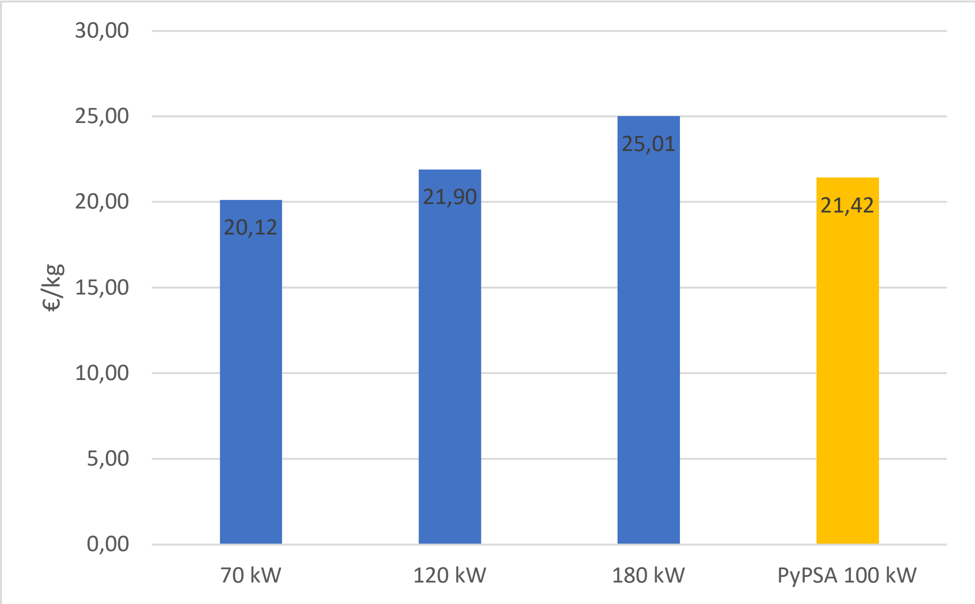

Figure 6.12 LCOH for all the hydrogen cases

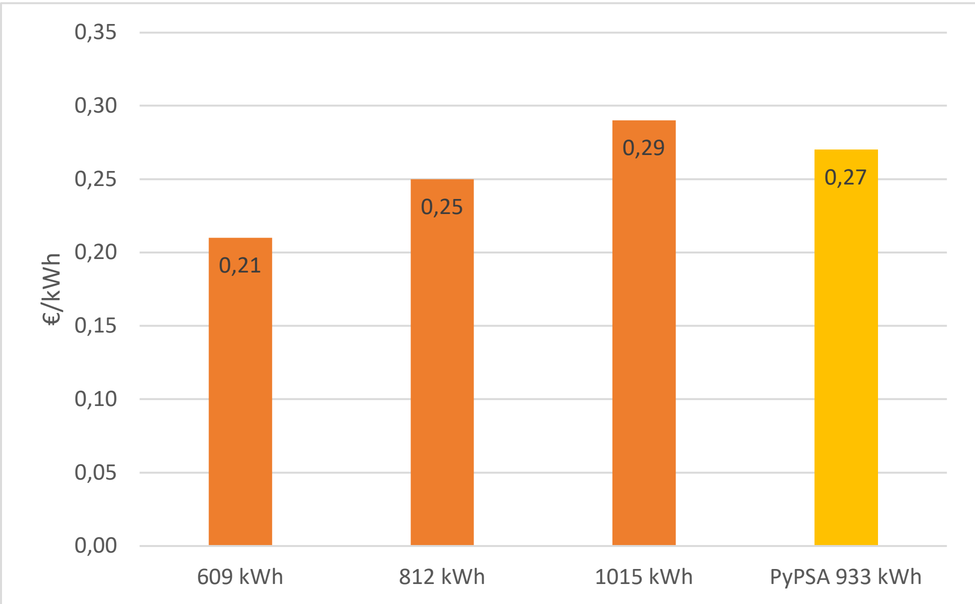

Figure 6.13 LCOEV for all the electric cases

In the next graphs, of significant importance, the contributions of each component to the total of Levelized Costs are highlighted. We can therefore see how in the case of hydrogen the electrolyzer and bulk storage, both around 5 €/kg, are the components with the largest share and therefore those on which a decision maker should act to reduce costs.

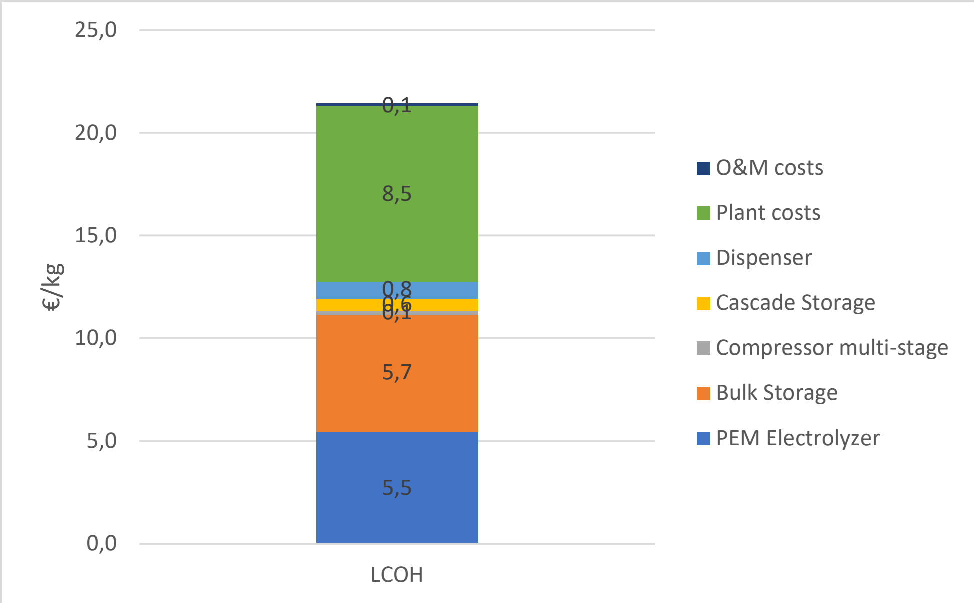

Figure 6.14 Optimal LCOH composition

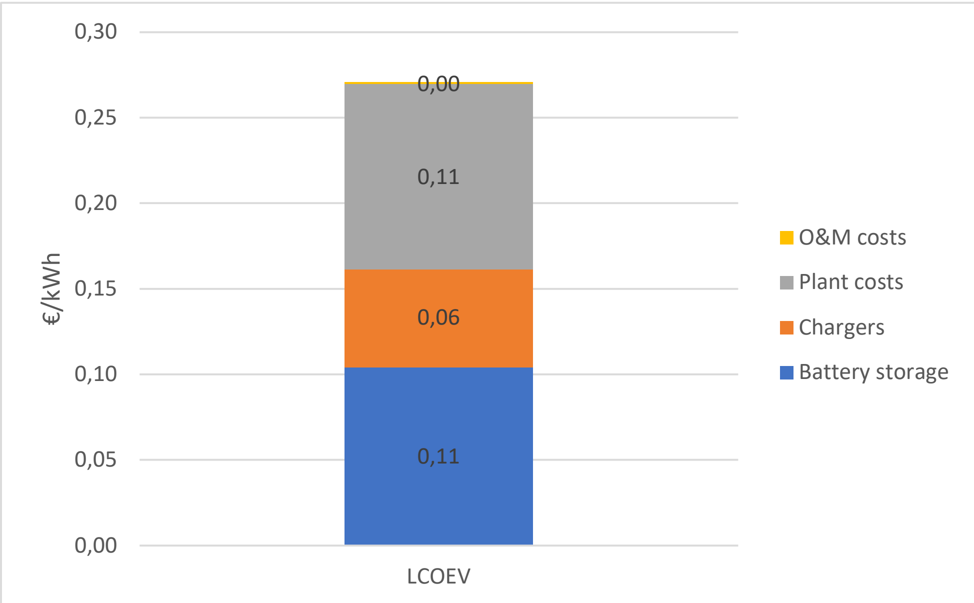

Figure 6.15 Optimal LCOEV composition

The cashflows are calculated in the same way before, considering the initial investment, the electricity sold (0.144 €/kWh) and purchased (0.108 €/kWh), the O&M costs, the incomes, the replacement costs spread over 20 years (about 3% for the hydrogen's case, 2.5% for the electric case) and a yearly insurance of 1%.

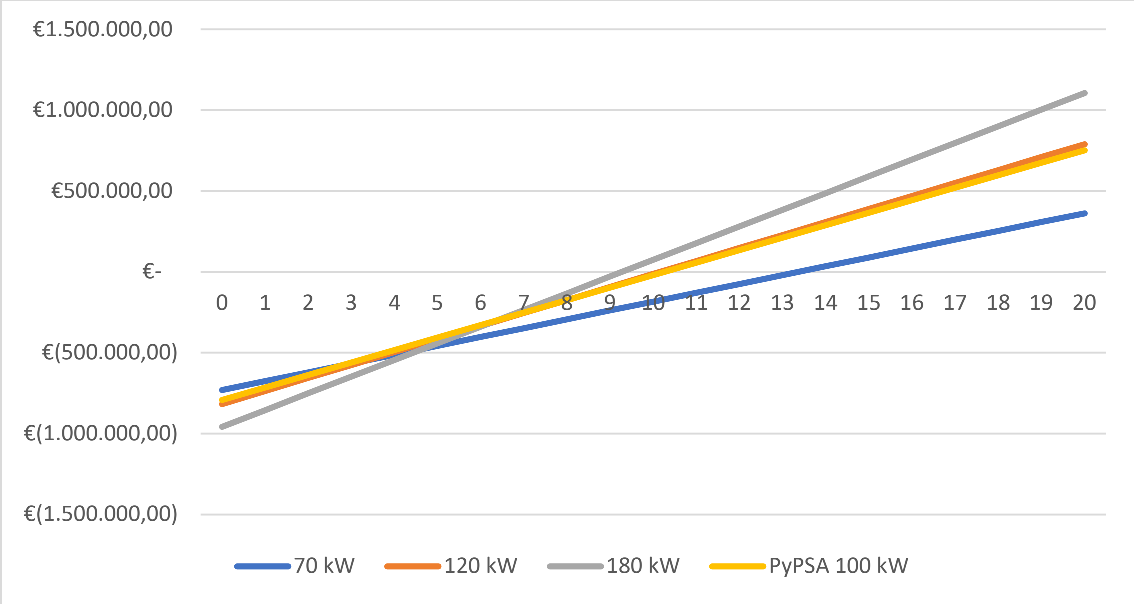

Figure 6.16 Cashflows of all the hydrogen cases

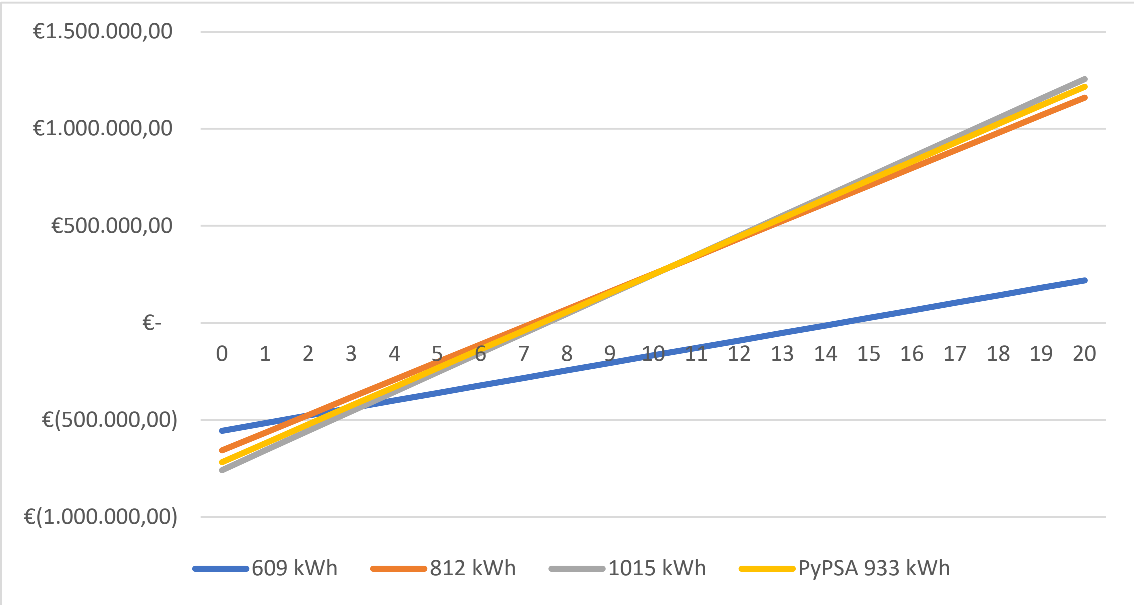

Figure 6.17 Cashflows of all the electric cases

The PBT for the optimized hydrogen's case is 10 years and 3 months, while for the electric case is 7 years and 5 months.

The choice to show all the techno-economic graphs again is due to the fact that, with the addition of the results obtained with the values found by means of PyPSA, it is possible to better visualize and analyze the cost's differences in the various cases. In fact, from the cash flows it is possible to note that the optimal case always lies in a sort of average between the cases previously analyzed.

From these results, the better economic performance of the electrical infrastructure is already evident, mainly due to the still non-competitive costs of the electrolyzer and hydrogen storage tank but also to the greater technological maturity of the components for the electric mobility, already widely installed and used all over the world.

6.3.1 Total costs of hydrogen and electric mobility projects

In addition to the specific costs for the two different infrastructures, it is useful to analyze the total costs of the projects, therefore also considering PV and wind power plants, and the buses (electric on one hand (Rampini E60) and fuel cell on the other (FCD Dolomitech) already presented in Chapter 2.

The costs per kW installed of the two electricity production plants are based on estimations made from reliable sources [52][53], while the costs of buses have been assumed by averaging those found online. Summarizing everything:

- Utility-scale PV plant on rooftops: 1,500 €/kW
- Small wind turbine power plant: 3,000 €/kW
- Rampini E60: € 305,000
- FCD Dolomitech: € 300,000

The costs of PV and wind power plant were used also on PyPSA to construct the simulation/optimization model.

Summing all the costs of the components of the optimal infrastructure and considering as before the BEC, EPCC, TPCs and TOC, the total investment costs of the two projects are evaluated:

- Hydrogen mobility infrastructure: € 4,265,086
- Electric mobility infrastructure: € 4,240,785

The similarity of these values is due to the buses costs which are almost the same, but more significant is their relevance to the total investment, as we can see in the following charts.

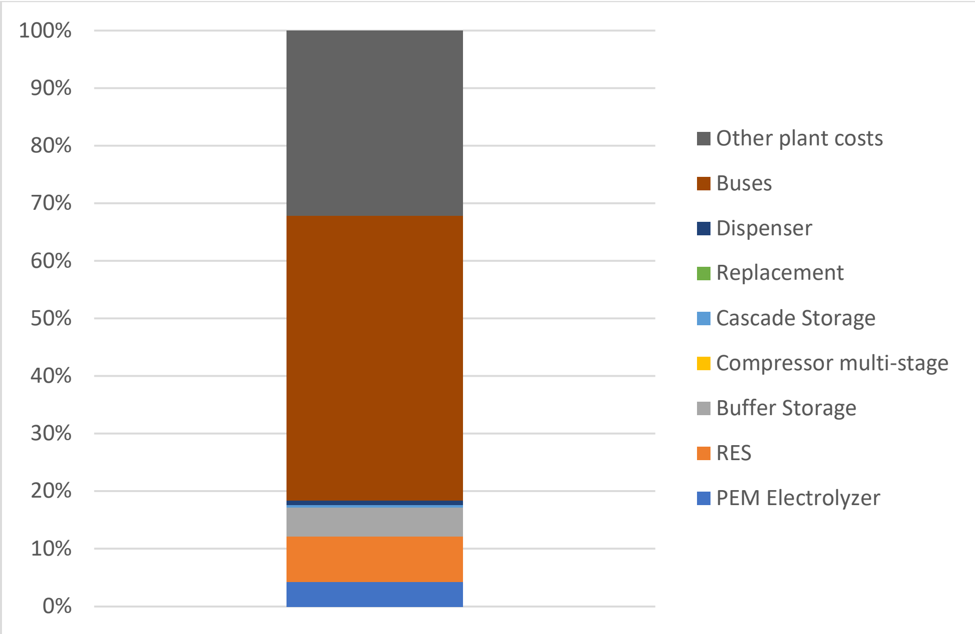

Figure 6.18 Total project's cost composition, hydrogen case

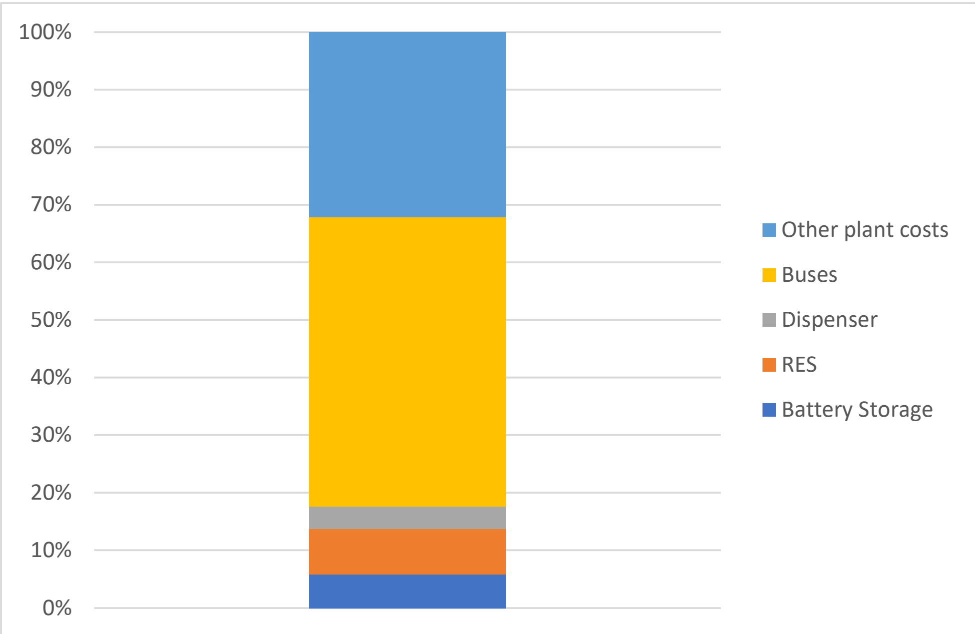

Figure 6.19 Total project's cost composition, electric case

Calculating the cashflows in this case has less significance as the incomes, which were previously calculated as hydrogen and electricity sold at the price dictated by LCOH and LCOEV, would be too low to recover the investment costs of the buses.

6.4 Hydrogen competitiveness

As previously stated, hydrogen is a key energy carrier for the energy transition and decarbonization of society. The great potentials such as high energy density and zero emissivity make hydrogen the fuel of the future. But the need to reduce CO_2 emissions in the shortest possible time goes hand in hand with the need to make hydrogen infrastructures, from purely energy to transport infrastructures, economically feasible and advantageous; for this reason, in this paragraph an analysis is carried out on the breakeven hydrogen costs at which hydrogen's mobility applications become competitive against low-carbon alternative: battery electric vehicles [54]. According to a study conducted by Hydrogen Council, passengers cars applications become viable with an LCOH around 3 €/kg, but heavy duty/medium duty trucks and long-range passenger vehicles can breakeven with BEVs at higher hydrogen production costs, between 4 and 6 €/kg (the target will be 5 €/kg) [54]; in fact, trucks, long-distance buses and large passenger vehicles are particularly competitive, as the cost of batteries required to secure the necessary range is very high for the battery alternatives [54]. In this case the target will be 5 €/kg. In the optimal case it has been calculated an LCOH of 21.4 €/kg, therefore it is needed the evaluation of the breakeven investment costs at which these two values will coincide.

By means of a "goal seek" with Excel, the target value was set to the LCOH by varying the COH, which in turn depends on the TOC and fixed OPEX. At the end of the procedure, the value of the TOC and of the fixed OPEX at which the LCOH becomes 5 €/kg is displayed.

	Previously calculated costs	**Breakeven costs**	**Costs reduction needed**
TOT PLANT COST	474,834.5 €	108,089.3 €	**-77.2%**
FIXED OPEX	13,596.7 €	3,094.9 €	
TOC	792,288.8 €	180,343.2 €	

Table 6.1 Breakeven costs of hydrogen infrastructure and needed reduction

The costs reduction that would make hydrogen more competitive in public transport applications should be mainly applied to the electrolyzer and storages which are the components with the largest share in the calculation of LCOH; in fact, the price of electrolyzers per kW is still too high to be competitive. But the lack of competitiveness is also the result of a technical maturity still to be achieved; a lower energy consumption in the production of hydrogen and, consequently, a greater efficiency would make it possible to use higher sizes of electrolyzers at the same cost. Finally, in order to make the penetration of hydrogen's applications in the market as effective and fast as possible, structured policies actions and therefore targeted incentives and subsidies should be applied.

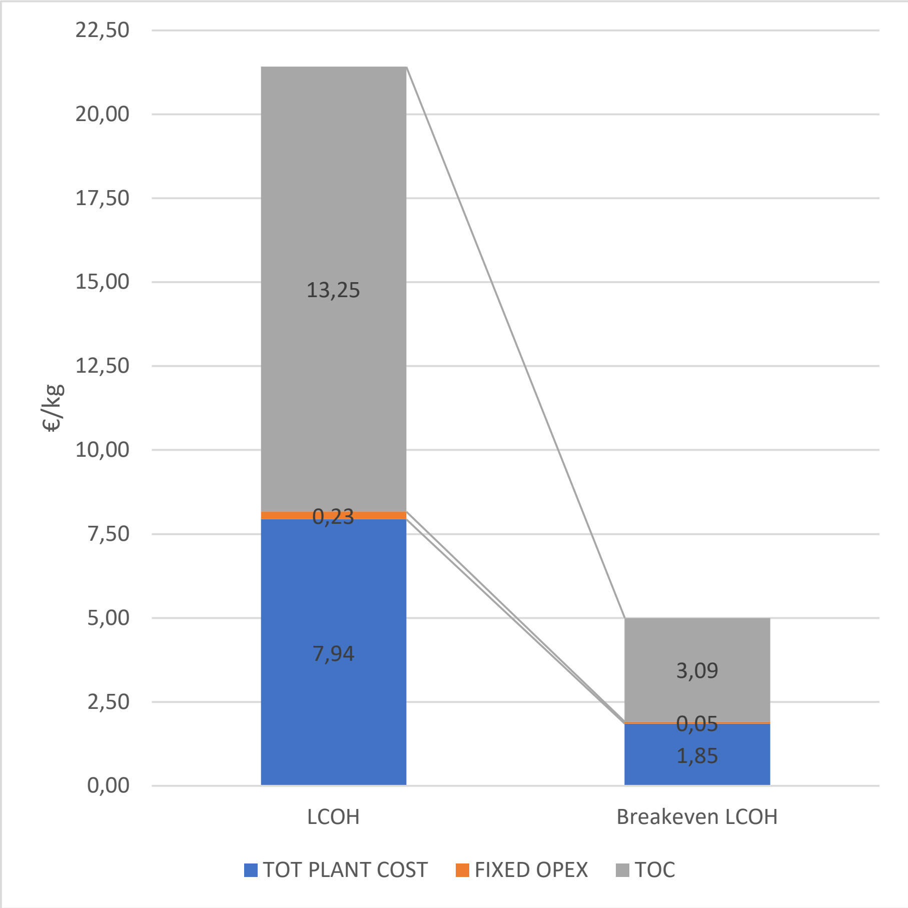

Figure 6.20 Reduction of the LCOH

7. Conclusion

The purpose of this thesis was to compare the technical and economic feasibility of two different sustainable public transport infrastructures on Pantelleria: electric and hydrogen. The electricity stored to then recharge the buses is produced by two renewable sources of energy (photovoltaic and wind power plant). The same electricity, coming from the same plants, is used in the other case, for the production of hydrogen through water electrolysis (green hydrogen), which is stored to then recharge the fuel cell buses.

The practically zero-emissivity of these two alternative mobility makes them the main solutions to decarbonize public, private, but also commercial transport. But, if electric mobility is already mature and enough developed to compete against fossil-fueled ones that still, but not for long, dominate the market, hydrogen production is not yet economically competitive to the point of being able to compete for a good share of market to other alternatives. For this reason, as last study of this thesis, the breakeven costs that would make hydrogen competitive against other alternatives have been calculated.

In recent years, hydrogen has begun to be increasingly present in the speeches of sector's experts, in plans for the energy transition of different nations, in reports and scenarios of intergovernmental organizations; all this is due to the great potential it has in the various sectors, but above all in the energy and transport sectors, two of the most polluting. Therefore, for a faster energy transition, which only with renewables or electric and hybrid cars alone would take longer, hydrogen is a valid solution. It should be specified that when we talk about an effective solution for the energy transition, we refer to green hydrogen, which produced through the electrolysis of water with electricity coming from renewable sources, turns out to be a zero-impact fuel from start to finish.

The results of this thesis show that at the moment the electric solution is the most advantageous in terms of performances, economic efficiency (PBT of about 7 years against 10 in the case of hydrogen) and Levelized Costs (0.27 €/kWh against 21.4 €/kg), but with the incentives proposed, a higher efficiency in production (≥ 70%) and lowering the costs of the components (costs reduction around 70%), hydrogen infrastructures will certainly be competitive (LCOH between 4 and 6 €/kg) and have a good share of the market.

The results achieved are in line with those found in literature and one last thing that could be underlined is that the Levelized Costs, especially in the case of hydrogen, would significantly decrease if more electricity from grid were used to produce H_2. This is because the full potential of the electrolyzer would be exploited, the capacity factor would increase with a consequent lowering of LCOH, which, making a simulation with the optimal case studied, would drop to about 9 €/kg, from a starting value of 21.4 €/kg. This will reduce the needs for incentives, but the economic performances should be carefully evaluated given the greater expenditure on electricity purchased and the need to exploit in some way the surplus of hydrogen produced, selling it or using it in other ways: fuel cells, boilers or other buses.

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