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Estimation of the potential of Power-to-Power systems in remote islands in Norway

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Abstract

Rising concern about climate change and keen awareness on the effect of GHG emissions make it clear that energy transition towards low-carbon systems has to be the focus of future energy scenarios. Energy efficiency, electrification of consumptions, energy production from renewables and CCS represent the fundamental pillars of the radical transformation of energy sector. However, in order to deeply exploit variable renewable energy sources and to ensure their integration into the electric system, energy storage strategies have to be developed: hydrogen represents indeed one of the most promising solutions. Green hydrogen production allows to store large amount of renewable power surplus by means of an energy carrier that can be converted again into electricity or used in hard-to-abate sectors, namely those fields in which decarbonization is difficult to achieve. Moreover, energy production from renewables and hydrogen storage in the so-called P2P systems is a viable strategy in remote areas and islands, in which energy demand is usually met by diesel generators or costly extension of national grid infrastructure. In this framework, REMOTE EU-project aims to assess the techno-economic feasibility of P2P systems in four demonstration sites in Europe, namely two islands (in Italy and Norway) and two remote areas (in Italy and Greece).
The present thesis work, that is developed as part of REMOTE project, aims to evaluate the potential of Power-to-Power systems in Norwegian islands. The analysis consists in the creation of a database which contains information of 138 islands; in particular, data related to population, geographical location, services provided on the island and sea cable connection (if present) are included. The 138 islands are grouped into 12 homogeneous categories on the basis of population and services; for each of them a single island, that is representative of the entire group, is selected and analysed in detail. The electric load of the 12 selected islands is estimated taking into account properly the characteristics of Norwegian buildings and the peculiarities of the location under investigation: in order to evaluate the residential electric load, a model based on specific literature data is developed while non-residential load profile is obtained from an Excel tool directly provided by a Norwegian research group. Energy production from renewables is evaluated by means of a MATLAB code that runs on meteorological data extracted from PVGIS and provides hourly values of power produced by wind and PV systems. Sizing procedure is performed by using a techno-economic optimization tool that is able to determine the sizes of the components and to evaluate the LCOE of the proposed solution. LCOE of hybrid P2P system is compared with that of four alternative scenarios: *only-hydrogen* and *only-battery* involving respectively the installation of PV-wind plant with only hydrogen or battery storage, *sea cable* that includes

the substitution of existing connection or the new sea cable laying and *diesel* in which energy demand is covered by diesel generators. LCOE of hybrid P2P system always results lower than that of only-hydrogen, only-battery and diesel scenarios, while the comparison with sea cable strictly depends on cable length and energy consumption. In addition, yearly fuel consumption and related CO_2 emissions are evaluated for the 12 selected islands; these outcomes are extrapolated for the 138 included in the database in order to assess on national scale the environmental benefits arising from P2P systems installation.

Keywords: Hydrogen, Power-to-Power, remote areas, islands, energy storage.

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Acronyms

CCS Carbon Capture and Sequestration

EMS Energy Management System

FCEV Fuel Cell Electric Vehicle

GHG Greenhouse gas

GIS Geographical Information Systems

IPCC Intergovernmental Panel on Climate Change

IRENA International Renewable Energy Agency

LCOE Level Cost of Electricity

LOH Level Of Hydrogen

LPSP Loss of Power Supply Probability

NPC Net Present Cost

NREL National Renewable Energy Laboratory

NVE Norges Vassdrags- og Energidirektorat

PSO Particle Swarm Optimization

RES Renewable Energy Sources

SOC State Of Charge

TD Transmission and Distribution

TMY Typical Meteorological Year

VRES Variable Renewable Energy Sources

WPD Wind Power Density

Chapter 1

Introduction

1.1 General background

Energy transition from fossil-based system towards a zero-carbon scenario represents the key challenge of this century. At its heart is the rising awareness on climate change and its relationship with GHG emissions.
It is now clear that the human activities are the leading cause of environment alterations; namely, according to IPCC, *«human influence has been the dominant cause of observed warming since the mid-20th century»*. [1]
The effects of GHG emissions are confirmed by countless studies: over the period from 1850 to 2012 the global average surface temperature, the CO_2 emissions and concentrations exhibit the same dramatically growing trend. In particular, the global average surface temperature has increased by 0.85 °C while CO_2 concentrations has almost reached 400 ppm and the global anthropogenic carbon dioxide emissions have exceeded 35 gTon/year. [2]
Thus, in order to limit climate change related risks, a significant reduction of GHG emissions is required in the short term with the aim of reaching net zero value in the next future. This goal can be achieved only with a *«large-scale transformation in the global energy-agriculture-land-economic system»*.[1] Focusing on the energy sector, the transformation consists in electrification of energy end-user, decarbonization of electricity and other fuels, energy-demand reduction and CCS. Therefore, a prompt action on a global scale is crucial.
In the past two decades, national and international authorities have adopted worldwide specific strategies in order to cope with these challenges.
EU has been at the forefront of addressing the root cause of climate change. In particular, the "2020 Climate and Energy package" and the "2030 Climate and Energy framework" set respectively the target to be reached in EU by 2020 and 2030: 20% reduction of CO_2 emissions by 2020 and 40% by 2030, 20% share of

renewable by 2020 and 32% by 2030 and 20% improvement in energy efficiency by 2020 and 32.5% by 2030.
In December 2015 during the Paris climate conference (COP21), 195 countries signed the Paris Agreement, the first-ever universal, legally binding global climate change agreement. The Paris Agreement central aim was to identify a strategy in order to keep *«the increase of global average temperature to well below to 2°C above pre-industrial levels pursuing efforts to limit the temperature increase to 1.5 °C above pre-industrial»*. [3] It also has the goal to achieve a balance between emissions by sources and removals by sinks of greenhouse gases on a global scale in the second half of this century. [4]
The decarbonization process of energy sector in Europe is well under way. The share of renewable in the gross final energy consumption has continuously increased over the past fifteen years: it started from 8.5% in 2004, doubled this value in 2016 and kept rising up to reach 18% in 2018.

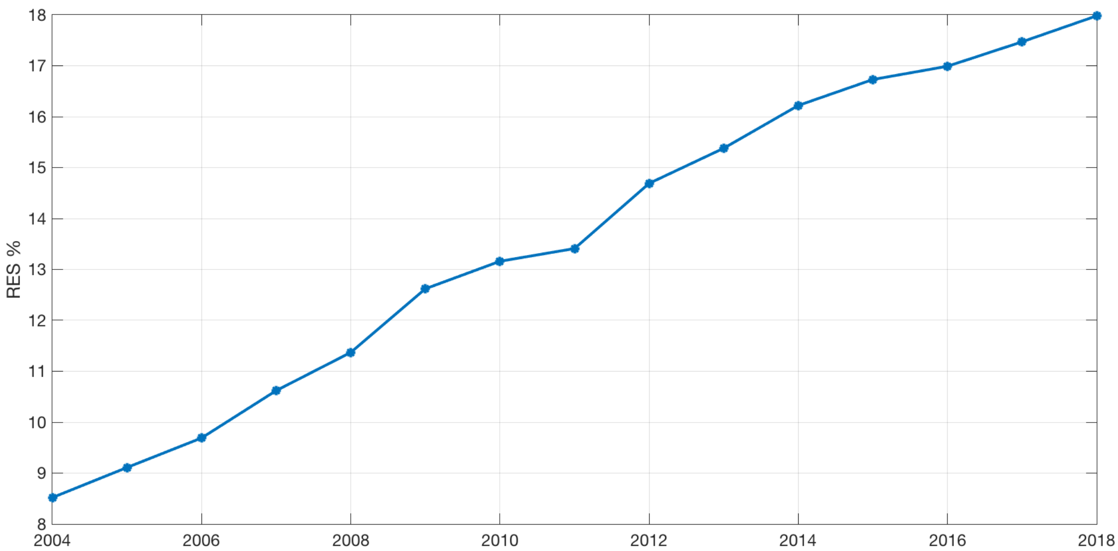


Figure 1.1: RES penetration in EU-28 gross energy consumption, 2004-2018. [5]

In absolute terms, the dominant RES market sector is still represented by heating and cooling, followed by electricity and transport. In 2018, 19.7% of the total energy use for heating and cooling in EU-28 was covered by renewable energy: in particular the largest contributions came from solid biomass, followed by heat pump and biogas. [6] The RES share in heating and cooling sector has almost doubled the 2004 value (10.4%). In 2018, renewable energy accounted for 8% of the total energy use in transport sector in EU-28 (including liquid biofuels, hydrogen, bio-methane and green energy). In the same year, more 32.1% of the electricity consumed in EU-28 was produced by renewables: in particular 33% by hydropower,

36% by wind, 9.5% by solid biomass and 12% by PV.[6]
The RES share in electricity exhibited the sharpest growth: namely, it has risen from 14.2% in 2004 to 32.1% in 2018, mainly due to the large-scale diffusion of solar PV and wind. [6]
A key factor for this significant increase was the sharp drop in the cost of electricity from PV and wind, which over the period from 2008 to 2018 have fallen by 75% and 50% respectively due to the capital cost reduction, increased efficiency and supply chain improvements. [7]

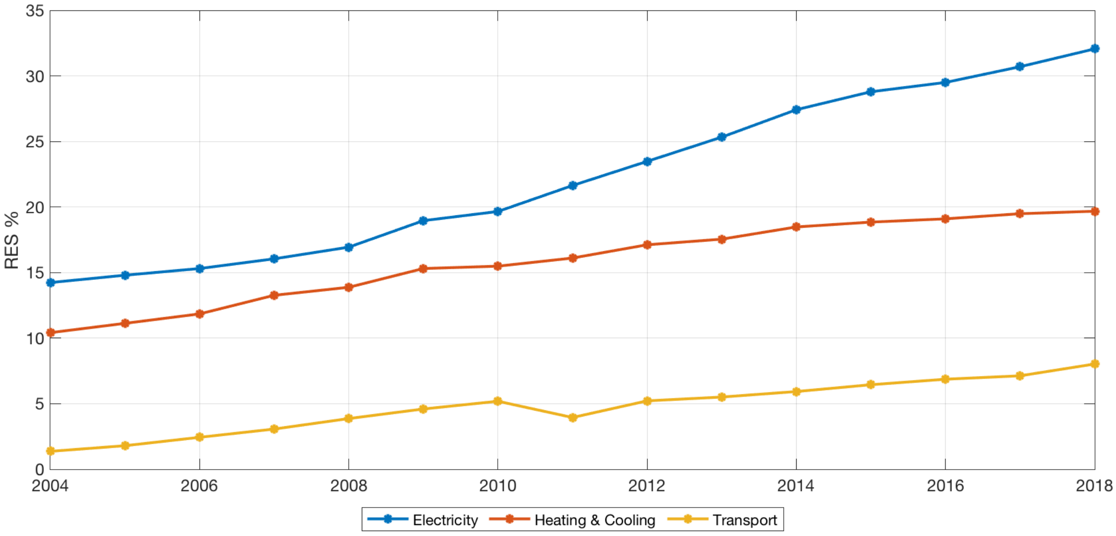


Figure 1.2: RES share in EU-28 gross final energy consumption by sector, 2004-2018. [5]

In Europe, over the past decade the wind power installed capacity has steadily grown, except for 2017 when 17.1 GW was installed. In 2019, 15.4 GW of wind power was added, reaching a total installed capacity of 205 GW. [8] Over the same period, new PV installation has exhibited a different trend: it reached its peak in 2011 with more than 20 GW of new installed capacity and then it declined reaching almost only 6 GW in 2017. In 2019 a sharp increase with new 16.7 GW occurred, reaching a total installed capacity of 132 GW. [9]
The increased use of RES since 2005 allowed EU to cut its fossil fuel consumption and related GHG emissions by, respectively, 168 Mtoe and 543 Mton CO_2 in 2018. [7] Nevertheless, EU is still the responsible of 10% of global greenhouse gas emissions and in particular energy sector accounts for more than 75% of EU's GHG emissions (including also international aviation sector). [4] Thus, a further effort is required to align the future energy system trends with 2050 decarbonisation goal; namely, even if EU were to cut its emission by 40% by 2030 a much deeper

reduction (two or three times larger than that required between current and 2030 levels) would be necessary between 2030 and 2050. [10]

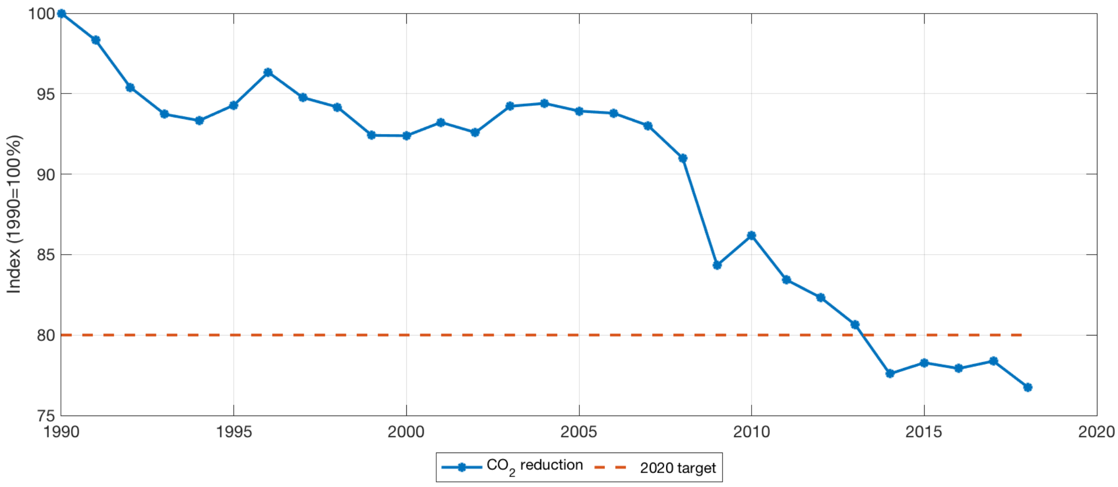


Figure 1.3: EU-28 greenhouse gases emission trend over the period 1990-2018. [11]

Therefore, renewables are crucial for long-term decarbonisation scenario and a significant increase of installed capacity is expected: according to REmap analysis by IRENA, in order to meet and potentially exceed the 2030 target, a total installed capacity of 327 GW for wind power, 270 GW of PV and 23 GW of hydropower, geothermal and CSP is required. The REmap scenario could allow to reach a 34% RES share in gross final energy consumption and 50% in electricity bringing the EU closer to a decarbonisation pathway compatible with the "well-below" 2°C established by Paris Agreement. [12]
The previsions made by IRENA are confirmed also by Wind Europe *Central Scenario* in [13], in which it is stated that 327 GW are expected to be installed by 2030; moreover, according to Solar Power Europe, 209 GW of additional PV capacity has to be installed in the next decade in order to overcome the 32% target. [14]
Despite of decreasing trend in costs and rising of performances, the intrinsic variability of PV and wind power makes the integration in the energy mix still challenging: intermittent production and sources variation (seasonal, daily and hourly) can determine a mismatch between load and production; moreover, variable power flows can stress transmission and distribution systems. Thus, the increasing share of VRES in the energy mix requires strong power system flexibility in order to ensure stability, reliability and balance between generation and consumption. Flexibility can be obtained with four different strategies: dispatchable generation, transmission and distribution expansion, demand side management and energy storage. [15][16]

According to [17], energy storage represents one of the most promising approach; therefore, it can play a key role in the future phases of energy transition. Energy storage can enable higher RES integration in the grid and it can provide many services to the electric system. [16] [18] In particular, it can ensure electricity time-shift: the surplus of energy can be stored and used when the demand overcomes the production; this solution allows to avoid the curtailment of RES surplus and the utilization of other sources to meet demand peaks. Moreover, by means of storage technologies, it is possible to convert electricity into other energy carriers (such as heat or hydrogen) to be used in different applications. Finally, energy storage can provide frequency reserve to the grid and it can also determine the deferral of transmission and distribution infrastructure investments. [16]
Electric energy storage can be performed using different technologies that can be classified, on the basis of the form of energy stored in the system, into mechanical (pumped hydroelectric storage, compressed air energy storage, flywheels), electrochemical (conventional and flow batteries), electrical (capacitors, supercapacitors and superconducting magnetic energy storage), thermal (sensible/latent heat storage), thermochemical (solar fuels) and chemical ones (hydrogen storage with fuel cell). [17]
Pumped hydro is the most diffuse energy storage technology and it is cost effective only in case of large storage capacity (typically from 100 to 200 MW) and it is not scalable. For this reason, pumped hydro is suitable only for systems with significant load variation between baseload and peak demand and it is highly site-specific, namely it is appropriate only for mainland grids. [19]
Battery storage represents a mature and modular technology, suitable for both grid connected and off-grid systems. [20] Improving performances and reducing cost make this solution attractive for short-term storage, but environmental issues related to production and disposal still represent barriers to be overcome. Moreover, battery lifetime is strictly dependent on depth of discharge and the efficiency is affected by ambient temperature. [19]
In the last few years, a new promising long-term chemical storage option has been investigated: the so-called Power-to-X solution. As stated in [21], the main properties that denote Power-to-X as a promising strategy are *«high storage capacity, high volumetric storage density, provision of system stabilization services, storage duration, flexibility to site topography and decentralized application possibility»*.
The simplest chemical output that can be produced in a PtX system is hydrogen: in the PtH_2 process water is split into H_2 and O_2 by means of RES driven electrolysis reaction. Oxygen is usually considered as a by-product and it is discharged into the atmosphere, but actually it can also be exploited in industrial applications or as oxidant in pure combustion reaction. Hydrogen can already represent a chemical storage medium or it can be involved in further conversion reactions in order to produce SNG or DME in the so-called Power-to-Gas and Power-to-Liquid

processes. The gaseous (H_2 or SNG) or liquid (DME) energy carrier can be finally converted back to power coming full circle in the PtP route. In the PtH_2 process, hydrogen can fed stationary fuel-cell for «time-shifted electric generation» or FCEV for mobility application or it can be even exploited in industrial field. [21]
Therefore, as stated by IRENA in [22], hydrogen is the *«missing link in energy transition»*: a large amount of renewable energy can be store producing H_2 that can in turn be used in sectors in which decarbonisation is difficult, such as industry, buildings and transport. Thus, hydrogen can increase the decarbonisation of these sectors, it can allow the integration of large amount of VRES and decouple VRE production and consumption.

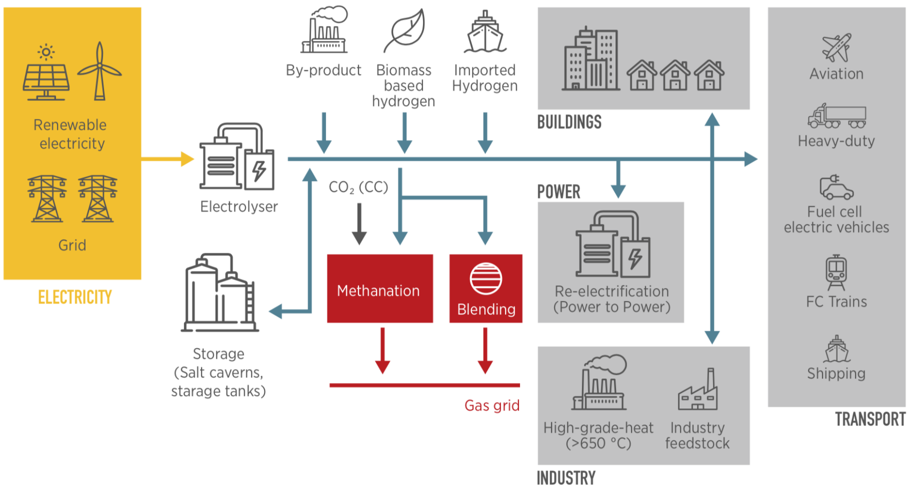


Figure 1.4: RES storage and H_2 applications. [22]

Moreover, in the medium-long term, hydrogen can become a way of transport and distribute renewable energy over long distances. For example, H_2 can allow to store in a cost-effective way the energy generated by offshore wind power: on-site produced hydrogen can be sent to the mainland by pipelines that can substitute very expensive subsea cables transporting electricity.
In addition, VRES and hydrogen storage can represent a very promising solution for remote areas (which usually depend on fossil-fuel or require expensive infrastructure to be connected to the main grid) and for off-grid regions (which often rely on diesel generators). VRES systems coupled with hydrogen storage can produce cheaper and more reliable electricity and they can reduce the environmental impacts and the dependence on imported fossil fuel.[19] Even if batteries are cheaper and characterized by higher roundtrip efficiency, in these applications hydrogen can ensure larger storage capacities, longer lifetime and higher temperature tolerance which is crucial in more extreme climates. [22]

In this framework, the REMOTE EU-project aims to demonstrate the technical and economic feasibility of fuel cell-based H_2 energy storage systems in off-grid or remote areas. In particular, four DEMO sites in four different locations across Europe (Italy, Norway and Greece) are analysed; the RES based plants are sized for two islands (Ginostra and Froan) and two isolated micro-grids (Ambornetti and Agkistro) in order to meet the electric load exploiting the local sources avoiding the use of diesel generator or the installation of new grid infrastructures.

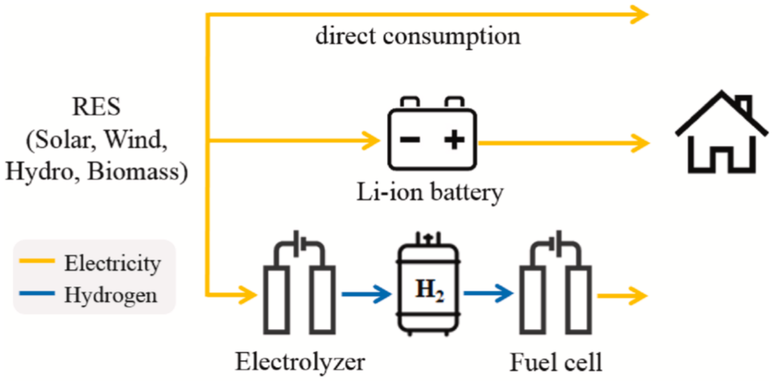


Figure 1.5: REMOTE project strategy. [23]

1.2 Aim of the thesis

The aim of this thesis work is the evaluation of the potential of Power-to-Power system in remote islands in Norway. Firstly, a detailed literature review of RES-based systems coupled with energy storage (i.e. battery, hydrogen and hybrid configuration) is carried out. Then, a database containing relevant information on Norwegian islands is developed; after a multiple-step sorting procedure, 138 islands are identified and grouped into 12 homogeneous categories: for each subset, a representative island is selected and analysed. After the implementation of load estimation procedure, a mathematical formulation of RES production is provided and the rationale of the techno-economic optimization is described. For the 12 selected islands a feasibility study is carried out: the optimal configuration that minimizes LCOE while ensuring complete autonomy is determined; the LCOE of H2-battery solution is compared with four alternative scenarios: only-hydrogen, only-battery, sea cable and diesel. In addition, the environmental benefits arising from the installation of Power-to-Power systems on a national scale are assessed: yearly avoided diesel consumption and CO_2 emissions are evaluated. Finally, the effects of energy autonomy requirement on LCOE is investigated in a sensitivity analysis.

Chapter 2

Literature review

Energy production in islands, remote areas and off-grid regions represents a worldwide challenge. In these locations electricity is usually produced with diesel generators, but this solution has several drawbacks. Firstly, the community is exposed to fuel price fluctuation and even the extra-cost associated with the transportation (usually by helicopter over long distances) has to be considered. [24]
In addition, diesel generators have to fulfil the energy demand usually working at partial load, thus with lower performances, higher fuel consumptions and emissions; this control strategy is required to continuously adjust the output power, but it increases the O&M cost and reduces the lifetime of the plant. [19]
Moreover, diesel generators require frequent maintenance and spare parts which can determine service breakdowns that can be even amplified by locations remoteness. Therefore, these systems have to cope with several challenges: security of supply, system stability and reliability, CO_2 local emissions and high energy cost. [25]
As an alternative to diesel generators, sea cables and national grid extension are usually considered and adopted. However, grid infrastructure realization is expensive, technically challenging and it can be environmental impacting. [24]
Furthermore, sea cables can undergo a series of malfunctioning during their lifetime and especially in case of very remote and sparsely populated islands the economic feasibility is uncertain. [26]
Nevertheless, remote areas and islands frequently have a significant RES potential: for instance remote mountain areas can rely on small hydropower plants and biomass, Mediterranean islands can take advantage of huge solar radiation and high-latitude islands can exploit abundant wind resource.
For these reasons, energy production exploiting local RES represents an attractive alternative solution: RES based systems can contribute to reduce fossil fuel consumption, emissions and costs.
However, due to the RES intermittency and load variability, energy storage is required in order to ensure the energy supply to the final users. Different storage

technologies can be adopted: battery-based, H2-based and hybrid H2-battery solutions are usually implemented.
In literature several articles which analyse P2P systems in islands and remote areas can be find. In the next paragraphs a literature review of the different schemes with a particular focus on island applications is presented: for each study location, load, plant components and corresponding sizes and LCOE are summarized.

2.1 Battery-based systems

Chmiel et al. in [27] analyse a hybrid RES based plant in Isle of Eigg, in Scotland. The system is composed by 119 kW of hydropower, 24 kW of wind, 54 kW of PV, 160 kW diesel generator and 48 V battery bank with 4400 Ah of capacity.
The 357 kW system has to fulfil the energy demand of 38 household and 5 commercial unit with a maximum peak load of 225 kW. In this case the investment cost was covered by government subsides. The LCOE was evaluated for two different load conditions: 856 kWh/day and 1000 kWh/day, resulting respectively equal to 0.2 £/kWh and 0.212 £/kWh.

Kaldellis et al. in [28] investigate the potential of hybrid wind-PV-battery systems in different islands in Greece. The study focuses the attention on the effect of the source availability on systems cost.

Tao Ma et al. in [29] analyse the feasibility of PV-wind hybrid plant coupled with battery storage in a small island in Hong Kong with a daily consumption of 250 kWh/day. The optimal configuration results in 145 kW of PV, 10.4 kW of wind, 168 battery and 30 kW converter, with a LCOE of 0.595 $/kWh.

Kit Gan et al. in [30] propose a PV-wind-diesel hybrid plant with battery storage in Bishopton, Scotland with a daily load of 15 kWh/day. The system is composed by 1 wind turbine, 20 PV panels, 3.3 kW diesel generator and 60 kWh of battery storage and the LCOE results 0.677 £/kWh.

Singh et al. in [31] analyse a RES based solution with battery storage for the electrification of Kavaratti island in India. The average daily load is 29333.57 kWh/day. The optimum configuration includes 1200 kW of PV, 750 kW of wind, 840 kWh of battery, 200 kW converter and 3800 kW of backup diesel generator, with a LCOE of 0.109$/kWh.

Sadrul Islam et al. in[32] assess the feasibility of a hybrid plant in St. Martin island in Bangladesh. The daily energy consumption is 78 kWh/day and the system is composed by 8 kW of PV, 6 kW of wind, 15 kW of diesel generator and 25 batteries (800 Ah each). The LCOE results in 0.345$/kWh.

2.2 Hydrogen-based systems

Chade et al. in [24] analyse the feasibility of wind-hydrogen system in Grimsey island, an Arctic remote location in Iceland. The island community relies on three 220 kW diesel generators; in order to find an alternative solution, three different scenarios are compared: wind-diesel, wind-hydrogen and wind-diesel-hydrogen. The latter turns out to be the most competitive: 300 kW of wind, 150 kW electrolyzer, 150 kW fuel cell, 250 kg hydrogen tank and 200 kW converter determine a LCOE of 0.295 $/kWh.

Enevoldsen et al. in [33] evaluate the feasibility of a wind-hydrogen solution for an off-grid community in Mykines, Faroe Islands. In order to completely avoid fossil-fuel, a 100% renewable energy system is designed: 120 kW of diesel generators are replaced by 88 kW of wind power, 42 kW of electrolyzer, 30 Nm3 of hydrogen tank and 50 kW of fuel cell. The yearly electric load is assumed 157210 kWh/year and the LCOE results in 0.53$/kWh.

Parissis et al. in [34] carry out a cost-benefit analysis of the integration of wind and hydrogen in the energy system of Corvo Island in Portugal. The yearly energy consumption of the 380 inhabitants is 1084 MWh/year and it is covered by 280 kW of diesel generators with a COE of 0.259 €/kWh. The optimized wind-hydrogen system consists of 200 kW of wind, 50 kW of fuel cell, 80 kW of electrolyzez, hydrogen tank of 200 kg and 280 kW of diesel generators. The LCOE is reduced to 0.145 €/kWh.

Kalinci et al. in [35] assess the techno-economic feasibility of stand-alone RES-hydrogen system in Bozcada island, Turkey. In particular, wind-hydrogen and PV-wind-hydrogen solutions are analysed and compared. The optimum configuration to supply 1875 kWh/day electric load includes 300 kW of PV, 660 kW of wind, 200 kW of electrolyzer, 100 kW of fuel cell and 150 kW of converter, with a LCOE of 0.83 $/kWh.

Gazey et al. in [36] provide a detailed field experience summary related to the wind-hydrogen plant installation in Unst island, Scotland. 30 kW of wind power, 3.55 Nm3/h electrolyzer, high-pressure hydrogen tank and 5 kW of fuel cell are able to supply five business properties.

2.3 Hybrid hydrogen-battery systems

Ulleberg et al. in [37] evaluate the performances of the wind-hydrogen demonstration plant at Utsira in Norway. The system includes two wind turbine 600 kW each, 10 Nm3/h alkaline electrolyzer, 11 Nm3/h hydrogen compressor, 2400 Nm3 hydrogen tank, 50 kWh of battery storage, 55 kW hydrogen engine generator and 10 kW PEM fuel cell. The system has to supply 10 households and it can provide 2-3 days of autonomy.

Groppi et al. in [25] analyse and compare different storage technologies in order to find the most suitable solution to increase the RES share and energy autonomy of small islands. In particular PV-battery, PV-hydrogen and PV-hybrid storage system are sized for Favignana island in Italy. On the basis of techno-economic and environmental indicators, battery-hydrogen storage system represents the most viable option to meet the electricity and public transport demand of the island: 900 kW of PV, 50 kW of electrolyzer, 705 kWh of battery determine a LCOE of 0.257€/kWh.

Kennedy et al. in [38] propose a RES-hydrogen system able to completely meet the energy requirement of Isle of Eigg in Scotland.
The analysis of RES generation and electricity consumption data shows that with the original configuration proposed by Chmiel et al. in [27] back-up diesel generators ran occasionally in eight months in one year. Therefore, 80 kW of wind power, electrolyzer and hydrogen storage tank are added to the existing system and the diesel generators are converted into H2-fed ones. The COE of the new system results in 0.776 $/kWh.

Garcia et al. in [39] perform a techno-economic analysis of a RES based plant with hydrogen-battery storage in Santay Island in Ecuador. In order to supply electricity to 46 houses, the system is composed by 36 kW of PV, 15 kW of hydropower, 6 kW of fuel cell, 10 kW of electrolyzer, 10 kg of hydrogen tank and 25 kWh of battery with a LCOE of 0.254 $/kWh.

Kalamaras et al. in [40] design a hybrid PV-wind plant with H2-battery storage to fulfil the electric and thermal demand of a remote off-grid household in Hydra island in Greece. The optimal configuration results in 3.35 kW of PV, 3 kW of wind, 2.9 kW of fuel cell, 4.3 kW of electrolyzer, 70 kg of hydrogen tank and 17.64 kWh of battery with a LCOE of 1.65 €/kWh.

Chapter 3

Norwegian islands analysis

In this chapter a general overview of Norwegian islands typologies and peculiarities is provided. Moreover, the database creation procedure is described in detail, with clear focus on data collection and classification according to population, community services, current electrification system and renewable energy potential. Finally, homogeneous categories are introduced and representative islands are selected.

3.1 Islands typologies and peculiarities

Norway has approximately 50 000 islands (including also islet and skerry) which differ in size, number of inhabitants and distance from the mainland.
Analysing the islands distribution, it can be highlighted that most of them are located near the coastline, but some lie in remote locations several kilometres far from the mainland.
On the basis of permanent inhabitants, Norwegian islands can be classified into populated and unpopulated. However, it is necessary to note that even islands without permanent population can host several hundreds of people during summer months in cottages, holiday houses and cabins.
Moreover, the all year-round population size can vary considerably between different islands: namely, there are some with only few people living on them and other with more than thousands of inhabitants. In addition, even on inhabited islands the population can change significantly during the year, especially between winter and summer due to tourism and seasonal working activities.
Fishing, agriculture, farming, aquaculture and tourism are the main activities that are carried out on small islands, while fish-process industries are usually located in medium-large size islands.
The services provided on the islands are strictly dependent on their size: usually small islands do not have school, stores or hospitals as opposed to medium-large

size ones.
Islands are connected to each other and to the mainland mostly by boat or ferry and only rarely by bridge and road connection; therefore, even supply of essential commodities can represent a challenge for most remote areas.
Depending on their location, islands can be connected to the national electric grid (by means of conventional T&D systems or sea cables) or they have to rely on diesel generators.
Analysing the renewable energy sources potential in Norway it is necessary to note that while onshore the peculiar topography with steep valleys, natural lakes and fjords lends itself perfectly to hydropower development, near the coastline and offshore a very abundant wind resource could be exploited. [41] [42]
As regards the solar radiation, the national average potential is quite low with respect to south-Europe countries, but in southern Norway it is comparable with that of some locations in Northern Ireland, Poland and Sweden. [42] Solar resource distribution is almost uniform between inland and coastline, but it is strongly affected by latitude variations: namely, moving towards arctic region the solar radiation magnitude decreases as the number of sunlight hours available per year.

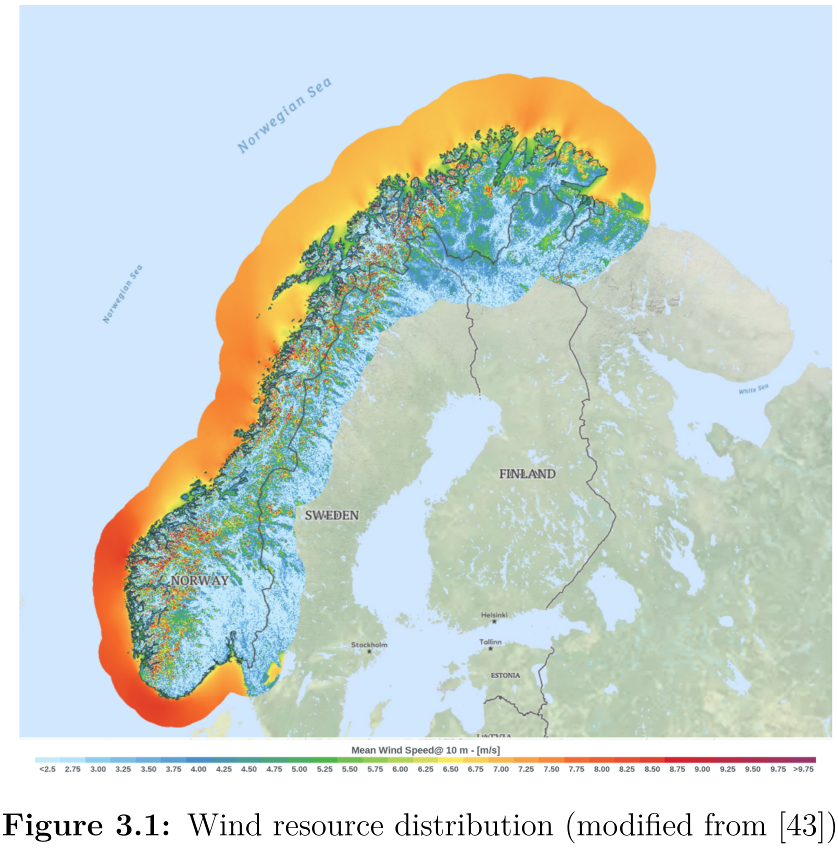


Figure 3.1: Wind resource distribution (modified from [43]).

Figure 3.2: Solar resource distribution (modified from [44]).

Solbakken et al. in [45] highlight the complementary behaviour of wind and solar resources in Norway in particular in high-latitude areas: namely, winter months are characterized by high wind speed and almost absent solar radiation while the opposite is true in summer.
Thus, the availability of wind and solar resources and the positive effect of their simultaneous exploitation put the focus on hybrid PV-wind system installation; moreover, the variability of electric load due to seasonal variations and the intermittent production of RES based systems emphasise the need of energy storage.

Therefore, a strong interest on P2P systems arises and a national level analysis is required to estimate the potential of this technology in Norwegian islands conditions.

3.2 Island data collection and classification

In order to perform a national scale analysis, it is necessary to carry out a census of Norwegian islands collecting detailed information and creating a database.
The database lists the islands sorted by county and municipalities and it contains:

1. Population on the basis of most recent available data;
2. Geographic coordinates and area in km^2;
3. List of services provided on the island;
4. Notes (e.g. tourism, summer houses, natural reserve status);
5. Indication of current electrification: sea cable (SC), transmission and distribution (TD), local grid (LG) or not connected (NC);
6. Sea cable information (length and year of installation);

Population data and geographical information are collected from *Store Norske Leksikon* website [46], while the services provided on the island are estimated on the basis on GIS and cartographical observations.
Finally, the information about the current electrification are extracted from the *Norwegian Water Resources and Energy Directorate* online tool [47].

In order to make a preliminary classification, according to the last administrative subdivision, 11 counties are considered: Adger, Innlandet, Møre og Romsdal, Nordland, Oslo, Rogaland, Troms og Finnmark, Trondelag, Vestfold og Telemark, Vestland and Viken.

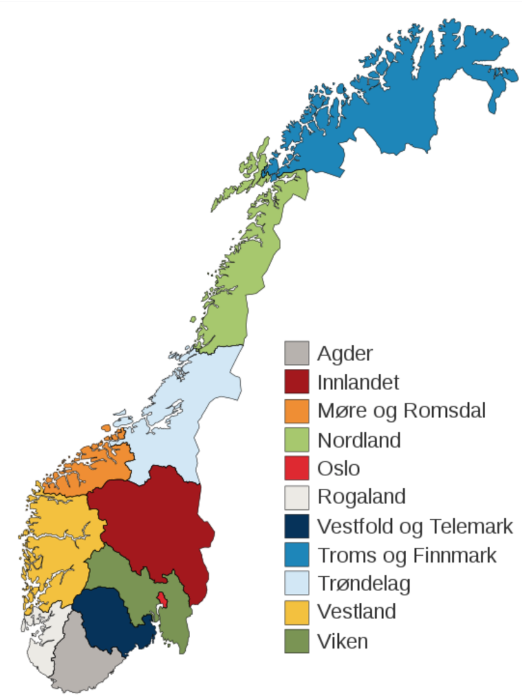


Figure 3.3: Norwegian counties. [48]

The database includes 495 islands, in particular 342 with complete information and 153 without reliable population data. The islands distribution among the counties is shown in Table 3.1.

Table 3.1: Islands distribution among counties.

County	Number of islands
Adger	41
Innlandet	1
Møre og Romsdal	65
Nordland	85
Oslo	9
Rogaland	34
Troms og Finnmark	56
Trøndelag	57
Vestfold og Telemark	26
Vestland	100
Viken	21

As can be noted in Table 3.1, Vestland, Nordland and Møre og Romsdal counties have the largest number of islands because of their peculiar rugged coastlines, followed by Trøndelag and Troms og Finnmark while Innlandet and Oslo counties have the lowest one due to location and limited extension, respectively.

As stated in Section 3.1, population sizes can vary significantly in Norwegian islands: namely, there are islands with less than a dozen of inhabitants and others with more than thousands. Thus, in order to provide a general overview of population sizes distribution, an islands classification based on permanent inhabitants is reported in Table 3.2.

Table 3.2: Population based classification.

Population range	Number of islands	Percentage
<100	138	40.35%
100-500	95	27.78%
500-1000	33	9.65%
>1000	76	22.22%

As evident in Table 3.2, a significant amount of islands (68.13%) has less than 500 inhabitants; this aspect points out the need of investigating them carefully and focusing on their current electrification systems. In fact, local electricity distribution licensees are required to provide energy supply even to these islands, despite of their small population.
Therefore, a detailed analysis of Norwegian electricity systems is performed by means of NVE online tool. This tool allows to examine the different voltage levels of national grid: transmission system at 132-300-420 kV (*Sentralnett*), regional system at 66-132 kV (*Regionalnett*) and distribution system at 22 kV(*Distribusjonsnett*); in addition, it indicates sea cable location and provides information concerning length, year of installation and voltage level. [47].
After evaluating the solution adopted by the islands included in the database, three different categories are identified: connection to the mainland through sea cable, absence of connection and connection to the distribution system. Furthermore, a fourth possibility is detected: in fact, several islands have a local grid at 22 kV but a direct connection to mainland or nearby islands is not specified by the tool.
These solutions are labelled respectively SC for sea cable, NC for not connected, TD for distribution system and LG for local grid. Possible electrification strategies are shown in Figure 3.4.

(a) *Sea cable* **(b)** *Local grid*

(c) *Distribution system* **(d)** *Non-connected*

Figure 3.4: Possible electrification systems (modified from [47]).

The results of islands classification basing on connection strategy are summarized in Table 3.3.

Table 3.3: Current electrification systems classification.

Electrification system	Number of islands
Sea cable	163
Local grid	64
Transmission and distribution	68
Not connected	35

Islands connected directly to T&D systems are not further included in the analysis since they usually have large population and they are very frequently located near the mainland with a solid electric infrastructure. In addition, because of their size they usually provide services whose electric loads are difficult to evaluate in absence of real measured data (i.e. bars, hotels, commercial activities and industrial sites). For the islands that are still under investigation a thorough survey of services provided on-site is carried out. The research focuses on local communities' key services: namely shop, school and kindergarten. The selection of these facilities allows to identify four different islands typology:

- Island than does not provide any services;
- Island with a shop;
- Island with an educational building and a shop;
- Island with two educational buildings and a shop;

As can be noted in the list above, islands are sorted with a progressively increasing level of services. The results of islands classification basing on tertiary sector activities are summarized in Table 3.4.

Table 3.4: Services provided classification.

Services provided	**Number of islands**
NO service	60
1 shop	22
1 school and 1 shop	36
1 kindergarten, 1 school and 1 shop	20

As stated in Section 3.1, near coastline and offshore a very abundant wind resource can be exploited. However, it is necessary to note that wind potential is not uniformly distributed across Norway: namely, it can differ considerably due to land conformation and climate conditions. Even solar radiation is highly variable depending on latitude, but in absolute terms its potential is substantially lower than wind one. Therefore, in order to perform an islands classification according to RES availability, wind resource is adopted as evaluation criteria.
Thus, a preliminary assessment of wind availability is carried out by using *Global Wind Atlas* online tool. [] More specifically, mean wind speed and mean wind power density at 10 m height are explored for insular locations. Approximate values of both parameters are collected for the different counties in Table 3.5.
Mean wind power density (WPD), expressed in W/m^2, is defined as:

$$WPD = \frac{\sum_{i=1}^{N} 1/2 \cdot \rho_i \cdot {v_i}^3}{N} \tag{3.1}$$

Table 3.5: Wind resource based classification.

County	Area	Average wind speed [m/s]	Average wind power density [W/m^2]
Adger	Aust-Adger Vest-Adger	4.5-5 5.5-6	100-150 200-250
Møre og Romsdal	North South	4.5-5 5.5-6	100-150 200-250
Nordland	North South	5-5.5 5.5-6	150-200 200-250
Rogaland	-	5-5.5	150-200
Troms og Finnmark	-	5.5-6	200-250
Trøndelag	North South	5.5-6 5-5.5	200-250 150-200
Vestfold og Telemark	-	4.5-5	100-150
Vestland	Hordaland Sogn og Fjordane	5-5.5 6.5-7	150-200 300-400
Viken	-	<4.5	<100

WPD provides an estimation of the amount of wind power per square meter of rotor-swept area that is available in a specific site and can be converted into electricity by a wind turbine. Since WPD takes into consideration frequency distribution of wind speed and the dependence of wind power on air density and cube of wind speed, it is a more accurate indicator than the mere wind speed. [49] [50] Therefore, according to WPD value the feasibility of wind resource exploitation in a certain area is determined: Wind Power Class definition provided by NREL is outlined in Table 3.6. [51]

Table 3.6: Wind power classes.

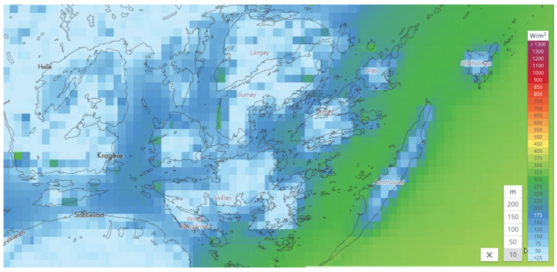
Wind Power Class	WPD [W/m^2]	Classification
1	<100	poor
2	100-150	marginal
3	150-200	fair
4	200-250	good
5	250-300	excellent
6	300-400	outstanding
7	>400	superb

On the basis of the data extracted from Global Wind Atlas and the Wind Power Class definition, a general evaluation of wind potential in Norwegian islands (sorted by county) is assessed. The results are summarized in Table 3.7.

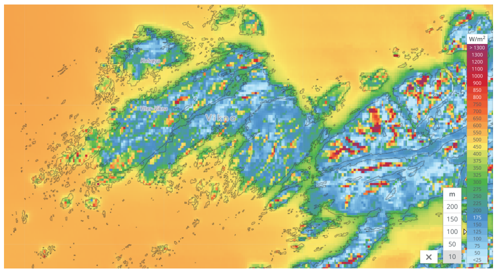
Table 3.7: Wind power density classification.

County	Wind potential
Adger	Marginal/Good
Møre og Romsdal	Marginal/Good
Nordland	Fair/Good
Rogaland	Fair
Troms og Finnmark	Good
Trøndelag	Fair/Good
Vestfold og Telemark	Marginal
Vestland	Fair/Outstanding
Viken	Poor

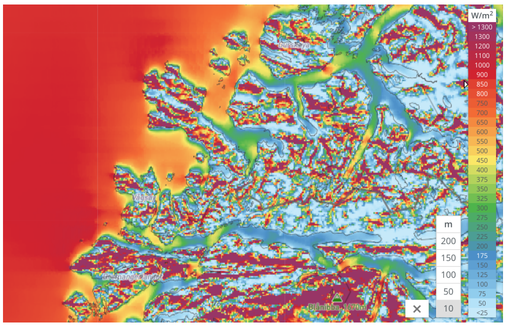
Obviously, this preliminary assessment only aims to provide a general indication of wind potential distribution: actually, islands with either lower or higher wind resource can be identified in each county. In Figure 3.5 three examples of wind maps extracted from Global Wind Atlas are reported: in 3.5a islands in Vestfold og Telemark county are shown, while in 3.5b Trøndelag insular locations are depicted and in 3.5c Vestland region is dispayed.



(a) *Low wind potential*



(b) *Medium wind potential*



(c) *High wind potential*

Figure 3.5: Wind resource maps. [43]

3.3 Selection of representative islands

After collecting a wide set of detailed information (i.e. geographical location, population, current electrification, provided services and RES availability) of Norwegian islands and classifying them according to a single criteria, islands can be grouped into homogeneous categories depending multiple assessment parameters. Therefore, focusing on islands labelled with SC, LG and NC, the classification based on provided services can be further developed introducing a population range indicator. Thus, starting from 138 islands grouped into the 4 categories shown in Table 3.4, 12 subcategories can be identified. Finally, a representative island for each subset has to be selected: in Table 3.8 the outcome of sorting process is reported.

Table 3.8: Representative islands.

Typology	Population range	Reference size	Reference island	Population	Represented islands	Code
NO service	0-50	25	Stottvær	27	41	STV
	50-100	75	Linesøya	77	15	LNS
	100-200	150	Fjøløy	179	4	FJL
1 shop	0-100	50	Selvær	55	13	SEL
	>100	-	Lurøya	138	9	LUR
1 school, 1 shop	0-100	50	Møkster	53	7	MOK
	100-200	150	Fjørtofta	136	9	FJT
	200-400	300	Lepsøya	313	12	LEP
	>400	-	Røst	498	8	ROS
1 kindergarten, 1 school and 1 shop	<100	-	Rovær	86	2	ROV
	100-350	200	Skrova	196	9	SKR
	>350	-	Værøya	640	9	VRY

As can be noted in Table 3.8, the selected islands try to cover as much as possible the wide range of insular locations typologies for both population and facilities.
In addition, it is necessary to emphasise that the reference islands are chosen also trying to be consistent with "reference size" value.
In Table 3.9 sea cable information of selected islands are summarized. It is necessary to highlight that in Fjøløy, Selvær and Lurøya island a real sea cable connection does not exist; therefore, the cable length is assumed equal to the distance from mainland.

Table 3.9: Sea cable information.

Island	Length [km]	Year of installation
Stottvær	2.8	1991
Linesøya	3.8	1980
Fjøløy	4.5	-
Selvær	34	-
Lurøya	7.6	-
Møkster	1.2	1954
Fjørtofta	2.9	-
Lepsøya	4.6	2011
Røst	33.2	2009
Rovær	7.8	2005
Skrova	9	1979
Værøya	27.9	1986

As is evident, sea cable connection represents a widespread solution: it is adopted either for islands near the coastline or for very remote locations; in addition, recently installed cables (i.e. Lepsøya, Røst and Rovær) confirm that this solution is still considered a valid option.
In the following sections, after outlining the adopted methodology, the 12 islands are analysed in detail: electric load and RES production are estimated, P2P system is sized and economic assessment is carried out.

Chapter 4

Methodology

In this chapter the methodology adopted in the study is described in detail. Firstly, the electric load estimation procedure is outlined: as regards residential load, the assumptions are listed and the implementation process of load model is summarized while as concerns non-residential load the operation of Excel tool is explained. Moreover, meteorological data source is indicated and mathematical formulation of the RES production estimation is provided. Furthermore, the rationale of optimization tool applied during system sizing is described and the assumptions of techno-economic analysis are highlighted. Finally, the alternative scenarios are introduced.

4.1 Residential electric load

Due to the absence of real measurement, the residential electric load has to be estimated on the basis of literature data. It is necessary to highlight that the majority of load models available in literature does not fit with Norwegian case study due to the specific features of environmental conditions and living standards. Namely, as claimed by Kipping and Thømborg in [52], more than 50% of Norwegian dwellings is represented by detached house and the most common space heating technology is direct electric heating system, often coupled with wood burning stoves or air-to-air heat pumps.

Moreover, as it typically happens in Nordic countries, the length of the days during winter affects dramatically the electricity consumption for lightning purposes. For these reasons, the residential load profile is expected to clearly show a seasonal distribution with the highest values during winter months, due to the combined impact of space heating and lightning demand.

In addition, the yearly average electricity consumption of a Norwegian household results in 16834 kWh/year: this value is considerably higher than other EU countries

average (i.e. 3790 kWh/year in Spain, 3334 kWh/year in Germany, 3535 kWh/year in Denmark and 2651 kWh/year in Italy). [53]
Therefore, in order to properly take into account the peculiarities of Norwegian household electric load, a *reference building's* load profile has to be developed. The *reference building* specifications based on [54] are shown in Table 4.1.

Table 4.1: Reference building specifications.

Charactestic	**Value**
Dwelling type	Detached house
Number of residents	2 adults, 2 children
Floor area [m^2]	150
Building year	<1980
Heating source	100% electric

According to [55], the following fragmentation of electric consumption is assumed:

- Space heating: 45%;
- Hot water: 12%;
- Lightning: 9%;
- Electric appliances: 19%;
- Residual: 19%.

With the aim of obtaining an hourly-based load profile a two steps procedure is implemented: firstly, the monthly average electric load values are extracted from [54] and then the daily distribution presented in [56] is applied.
More in detail, on the basis of the data reported in [54], the monthly average electric load and the mean value of daily minimum and maximum variations are evaluated for a household with an average daily electric consumption of 61.5 kWh/day. The results are shown in Figure 4.1. Then, the typical daily load profile is identified: the load pattern of a remote household in Southern Norway with an average daily electric consumption of 54 kWh/day is adopted as reference. [56]
Analysing the Figure 4.2, it can be pointed out that the reference load profile has two peaks during the day: namely, the first one in the morning (around 8 am) and the second one during evening hours (around 8 pm).
Therefore, by combining this information it is possible to create a daily profile for the different months: the reference load pattern is properly scaled in order to preserve the monthly average electric load and thus the monthly energy consumption. The results are shown in Figure 4.3.

By adopting this procedure, every day of each month exhibits the same load profile as it can be noted in Figure 4.4; thus, in order to obtain a more realistic set of data, two different random parameters are introduced: the *day-to-day* and the *timestep-to-timestep* variability indices. [57]

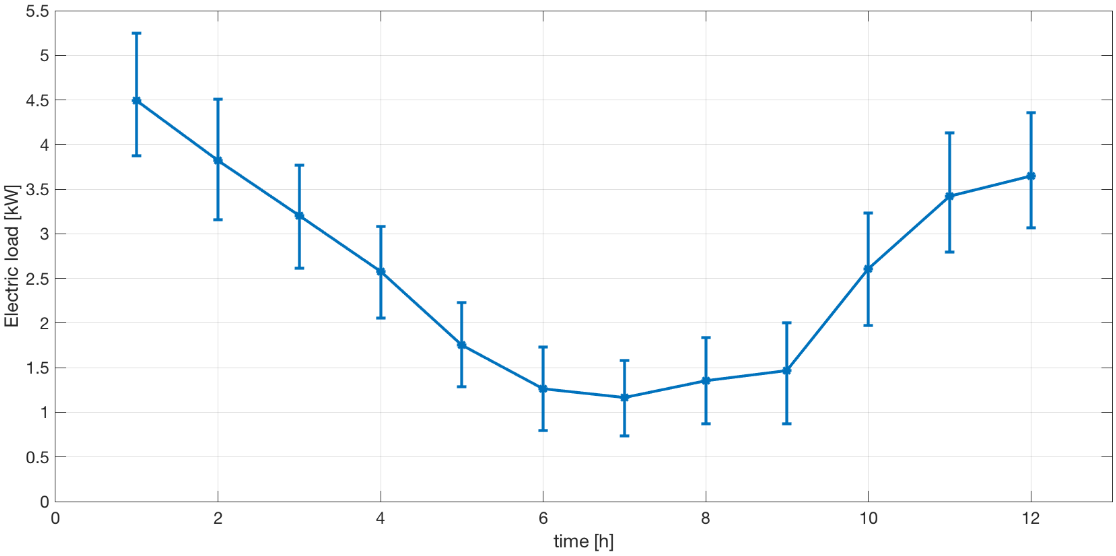


Figure 4.1: Monthly average electric load values.

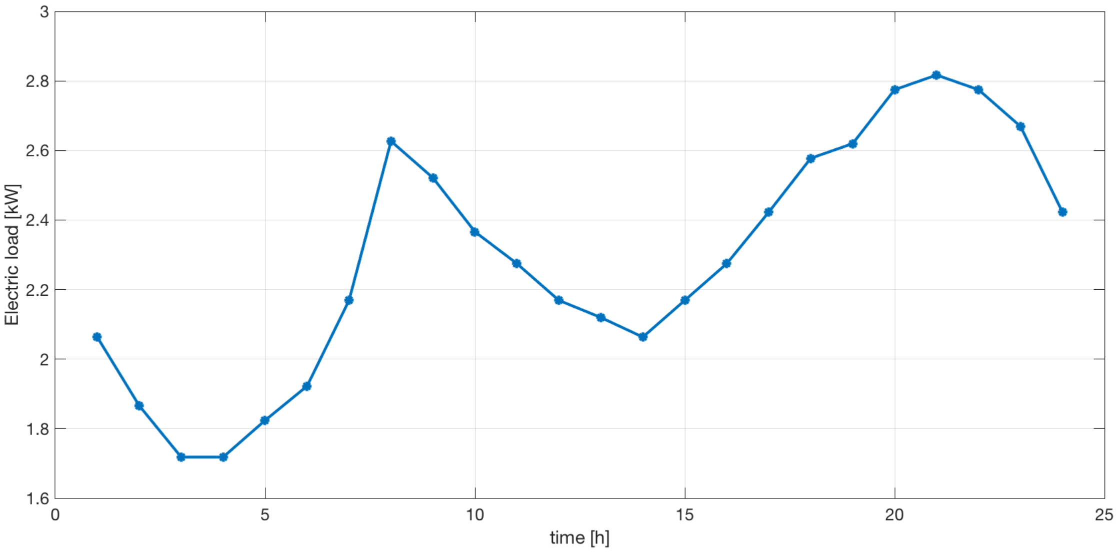


Figure 4.2: Reference electric load profile.

The *day-to-day* variability determines the random variation from day to day of the size of the load profile while leaving the shape unchanged. On the contrary, the

timestep-to-timestep acts on the shape without affecting the size. By combining the effects of these two parameters, it is possible to modify both the shape and the size and a variable and realistic electric load can be generated. [57]
In order to properly take into consideration the random variation, the constant electric load is multiplied by a correction factor, defined as:

$$\alpha = 1 + \delta_{day} + \delta_{timestep} \tag{4.1}$$

The δ_{day} is randomly evaluated once per day from a normal distribution with mean value equal to zero and standard deviation set to *day-to-day* variability value, while the $\delta_{timestep}$ is randomly generated once per hour according to a normal distribution with mean value equal to zero and standard deviation equal to *timestep-to-timestep* variability value. [57]
In this case the daily and the timestep variability parameters are assumed respectively equal to 12% and 5%. [54]
The resulting residential electric load profile is shown in Figure 4.5: as required, it clearly exhibits a seasonal pattern with random peaks and valleys.
The yearly electric consumption results in 22421 kWh/y and the monthly distribution is represented in Figure 4.6.

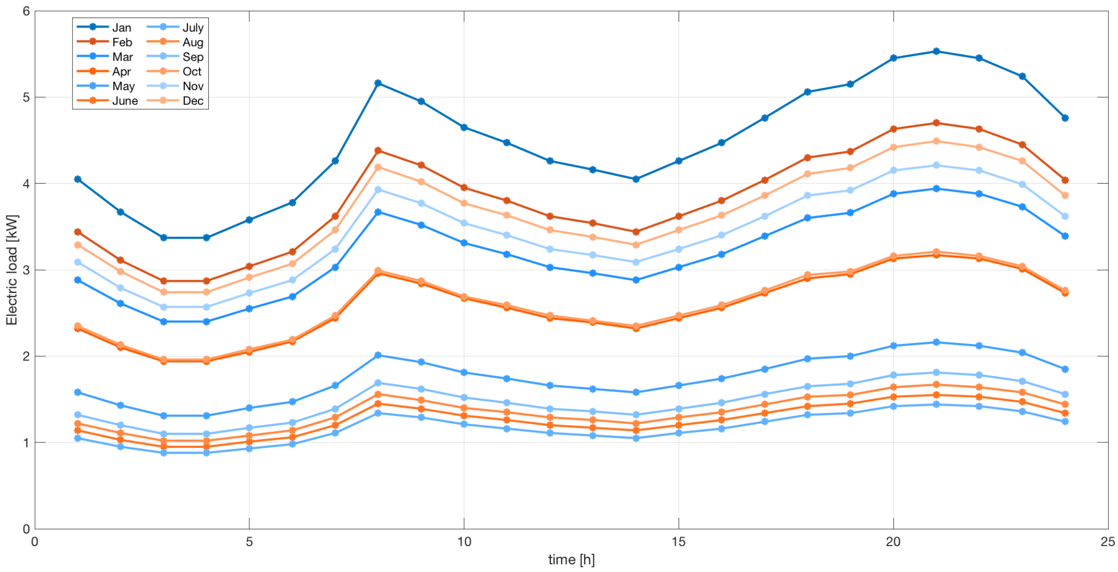


Figure 4.3: Daily electric load profile for different months.

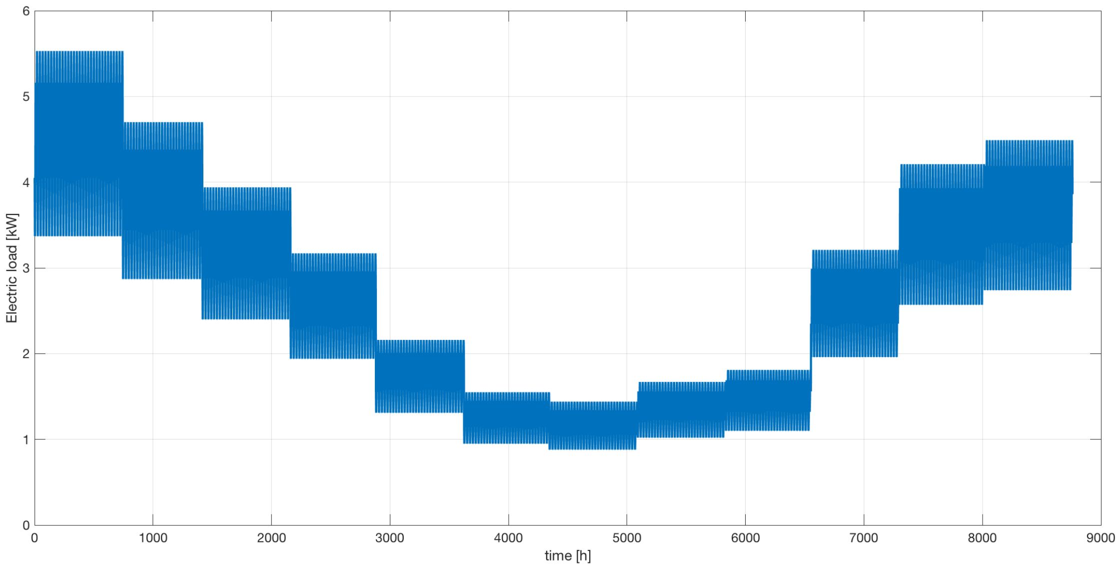


Figure 4.4: Hourly based residential load profile.

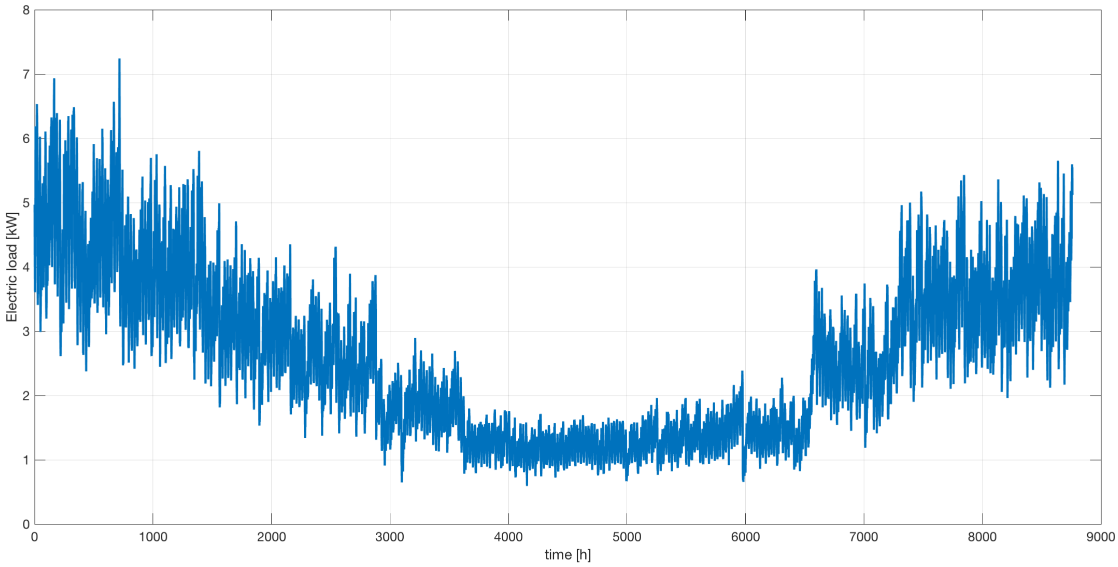


Figure 4.5: Modified hourly based residential load profile.

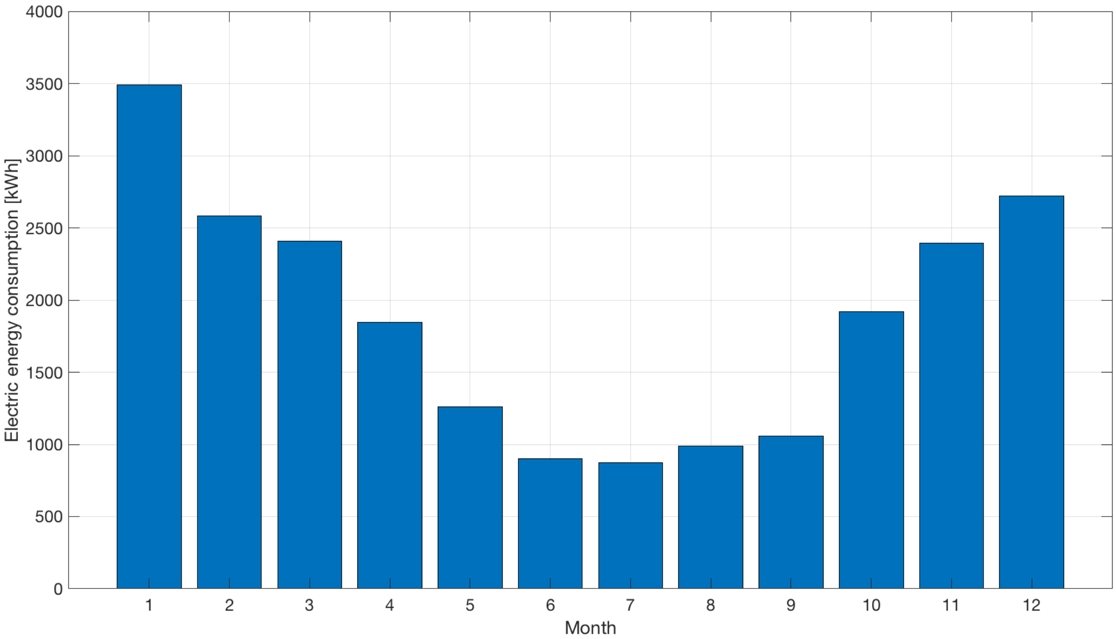


Figure 4.6: Monthly energy consumption.

4.2 Non-residential electric load

The non-residential building load profile is estimated on the basis of the regression model described in "Modelling electric and heat load profile of non-residential buildings for use in long-term aggregate load forecast", a scientific publication by K.B. Lindberg, S.J. Bakker and I. Sartori, researchers from SINTEF Building and Infrastructure and Norwegian University of Science and Technology (NTNU). [58]
In the paper, a methodology to separately estimate electric and thermal load is proposed: more in detail, electric load is defined as *«the energy demand that cannot be met by other energy carrier than electricity, i.e. lightning, appliances, funs and pumps»*, while the thermal load is considered as *«the energy demand required to satisfy the building's space heating and domestic hot water (DHW) needs»*. In addition, it is necessary to emphasise that the energy demand for cooling is included in electric load definition, since it is often met by electric driven solutions. [58]
As stated by Santori et al. in [59], in Norway electricity represents the most widely used energy carrier for heating purposes (both space heating and domestic hot water production) even in non-residential buildings: namely, energy generation from hydropower can ensure cost-effective and carbon-free electricity to be used to drive direct electric systems and electric boilers. Patronen et al. in [60] confirm that electricity is the *«dominant source of energy for heating and hot water in*

residential and service sector»: according to ENOVA, 85% of heating demand was covered by electricity in 2015. Therefore, in this study thermal demand in non-residential buildings is assumed to be met by electricity (e.g. direct electric systems and/or electric boilers).
The regression model is obtained from the analysis of hourly measured data from 116 non-residential building in Norway; in particular, 7 building typologies are analysed: kindergarten, school, office, shop, hotel, hospital and nursing home.
The regression model takes into account the building specific features and includes both the direct effect of temperature and that of 24-hours moving average. Furthermore, the model takes into consideration the operating mode of heating and cooling system; in fact, comparing ambient temperature with two specific values (CPT_H and CPT_C), three different load regions are identified:

- if the ambient temperature is lower than the CPT_H, heating mode is active and the load is temperature dependent;

- if the ambient temperature is between CPT_H and CPT_C, the load is temperature independent;

- if the ambient temperature is higher than the CPT_C, cooling demand occurs and the load is still temperature dependent.

Therefore, the energy consumption increases while reducing the temperature due to space heating demand, it is almost constant for DHW production and it increases while increasing the temperature due to cooling demand. It is necessary to note that the hourly values of CPTs are selected for each building typology in order to reach higher model accuracy.
The load depends on outdoor temperature, hour of the day and type of day (i.e. working day, weekend day and holiday) and the results are normalized with respect to floor area. Thus, in order to estimate the load only ambient temperature of the specific location and building dimensions are required. An Excel tool that post-processes the results explained in [58] is provided directly by the research group. The tool requires as input data the hourly values of ambient temperature and the size of the buildings expressed in m^2 and it elaborates hourly profiles and duration curves for both electric and thermal load.
Basing on the services provided on the selected islands, the load profiles of kindergarten, school and shop are modelled and analysed in detail.
At this point, in order to obtain general results, a floor area of 1 m^2 is adopted, namely the specific electric load in W/m^2 is generated. In addition, since a yearly temperature distribution is required, values of Rovær island are used.

4.2.1 Kindergarten

The kindergarten yearly energy consumption results in 179 kWh/m^2. The value obtained with the regression model is consistent with that provided by Statistics Norway in [61] and it is slightly lower than that provided by SINTEF in [62], respectively equal to 175 kWh/m^2 and 200 kWh/m^2.

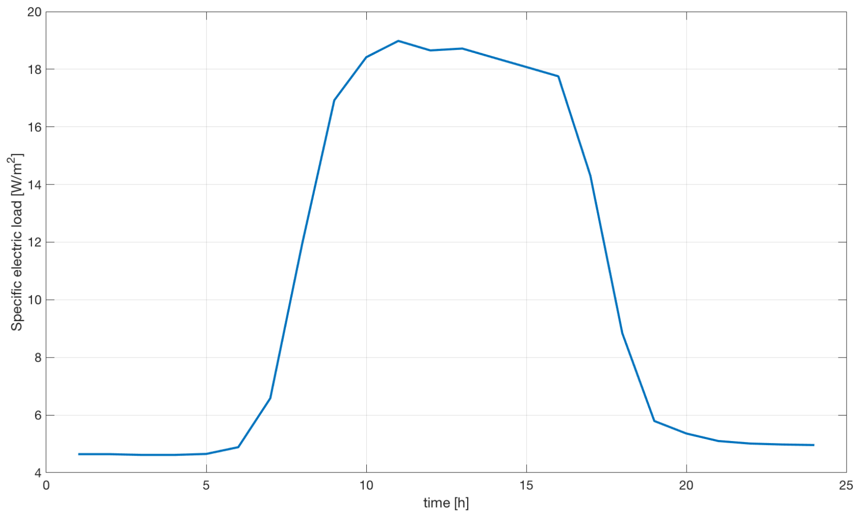


Figure 4.7: Kindergarten daily electric load.

According to [62], kindergartens are open on average 10 hours per day and 5 days per week, but they are usually in use also during summer months.

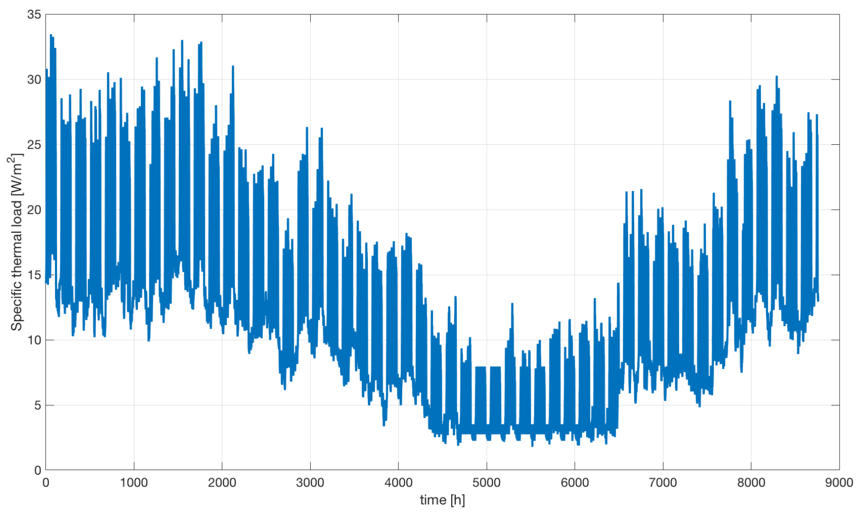


Figure 4.8: Kindergarten yearly thermal load.

Moreover, heating demand accounts for more than 60% of the total energy requirement since the set-point temperature is equal to 24°C. In Figure 4.7, the specific daily electric load is shown: it exhibits the typical bell-shape profile with a peak of almost 19 W/m^2 around 11 am and a flat behaviour near the maximum. In Figure 4.8 the thermal load profile is reported. The effect of temperature variation over the year is evident: the thermal demand is considerably lower during spring and summer, but it is still present due to DHW production.
In Figure 4.9 the cumulative load profile is show. It has the same trend of thermal load, but it is shifted towards up due to the electric contribution (that is almost constant during the whole year).

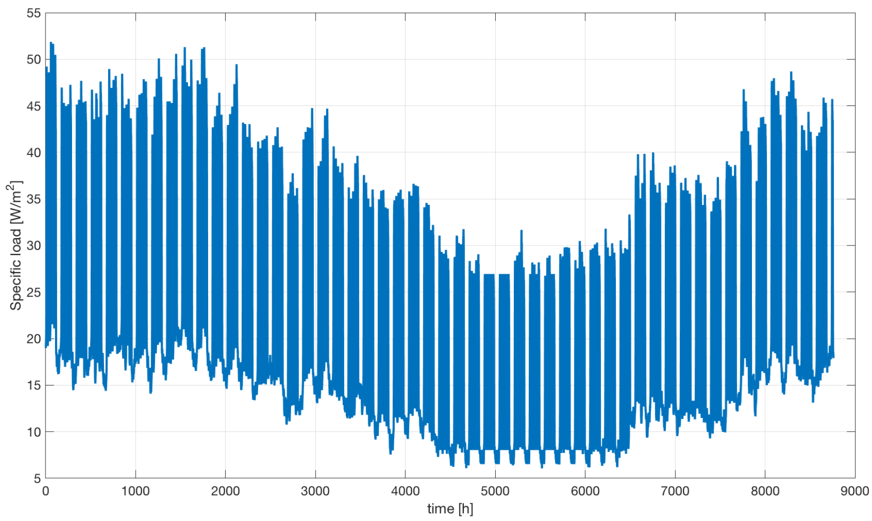


Figure 4.9: Kindergarten cumulative load.

4.2.2 School

The school yearly energy consumption results in 149 kWh/m^2. Even this value is in line with that provided by Statistics Norway in [61] and it is slightly lower than that provided by SINTEF in [62], respectively equal to 150 kWh/m^2 and 170 kWh/m^2. According to [62], schools are open on average 7-8 hours per day and 5 days per week, but they are usually closed during summer months. Moreover, even in this case heating demand accounts for more than 58% of the total energy requirement. In Figure 4.10, the specific daily electric load is shown: it exhibits the typical bell-shape profile with a peak of almost 16 W/m^2 between 12 am and 1 pm. In Figure 4.11 the thermal load profile is reported. The load variation reflects the temperature evolution through the year and during summer only DHW production contributes.

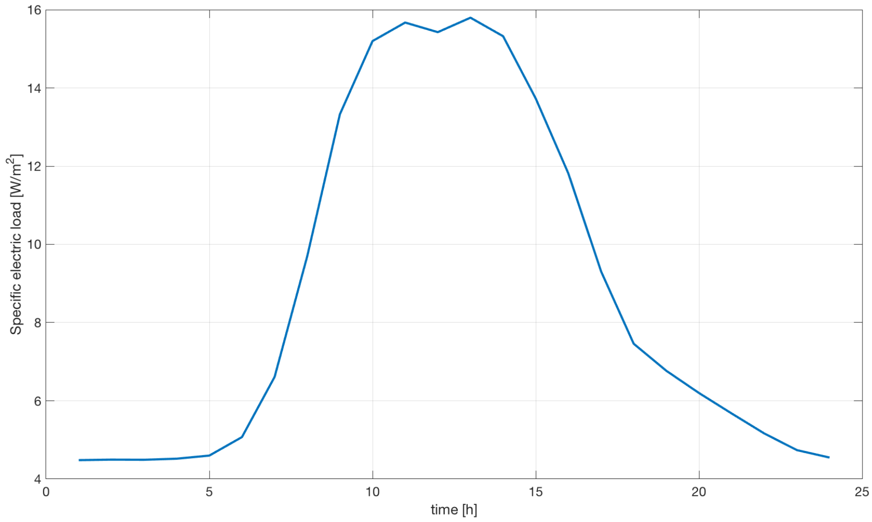


Figure 4.10: School daily electric load.

Comparing this profile with that of 4.8, it can be noted that schools have lower thermal loads due to the lower set-point temperature and opening time. [62].

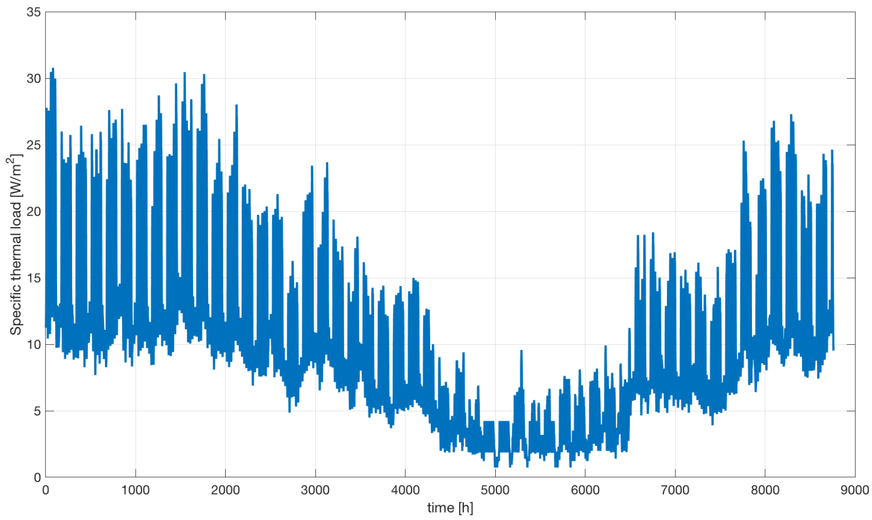


Figure 4.11: School yearly thermal load.

In Figure 4.12 the cumulative load profile is show. Even in this case, it has the same trend of thermal load, but it is shifted towards up due to the additional electric contribution.

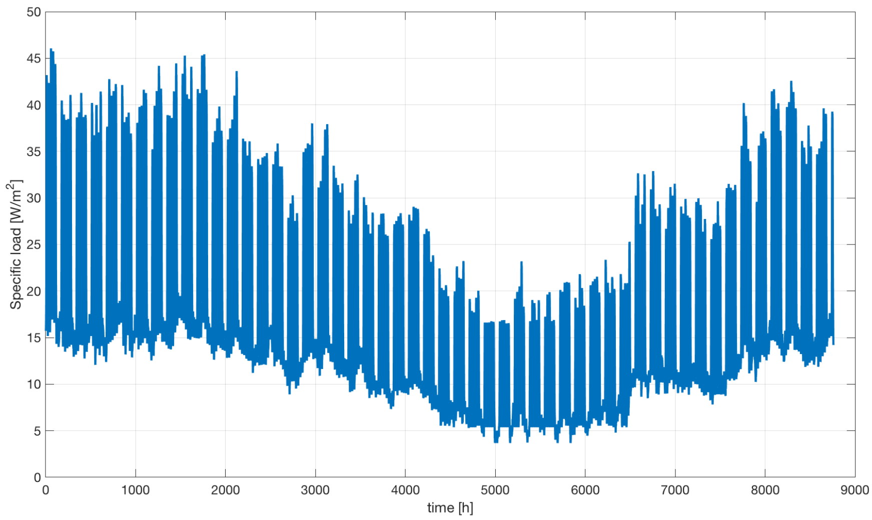


Figure 4.12: School cumulative load.

4.2.3 Shop

The shop yearly energy consumption results in 202 kWh/m^2. In this case, the model underestimates the energy requirement with respect to Statistics Norway in [61] and SINTEF in [62]. According to [62], the main contributions are related to

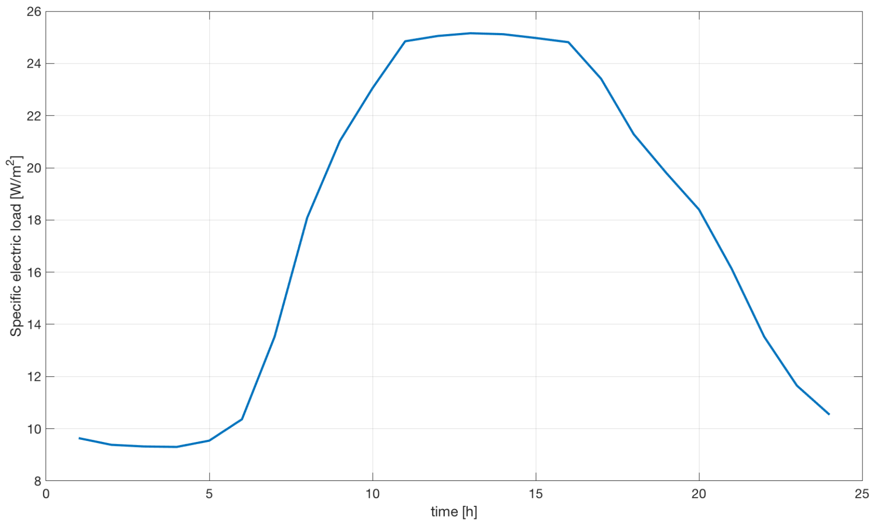


Figure 4.13: Shop daily electric load.

refrigeration systems and lightning; in this case space heating and DHW production are less impacting.
In Figure 4.13, the specific daily electric load is shown: the bell-shaped profile has

a quite flat behaviour near the maximum (that occurs at almost 25 W/m^2).
In Figure 4.14 and 4.15, thermal and cumulative loads are depicted: it is evident that the cumulative profile is less variable than that of kindergarten and school, since it is dominated by electric consumption.

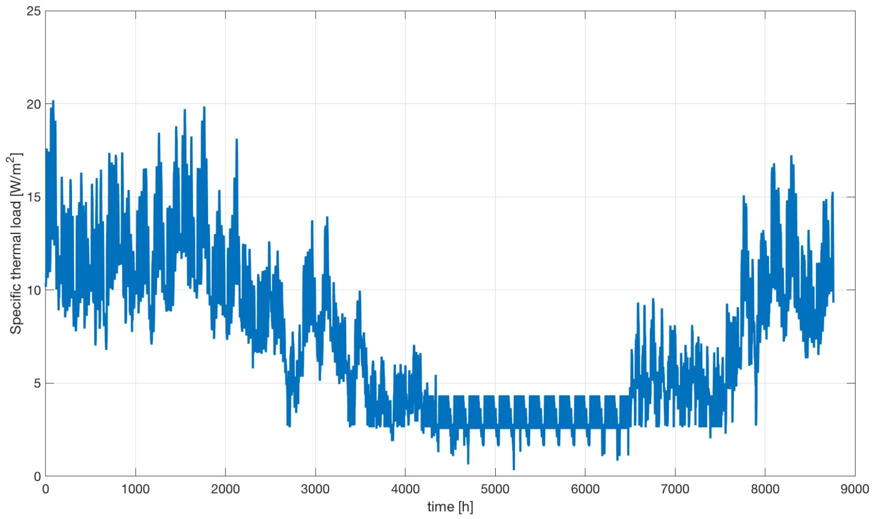


Figure 4.14: Shop yearly thermal load.

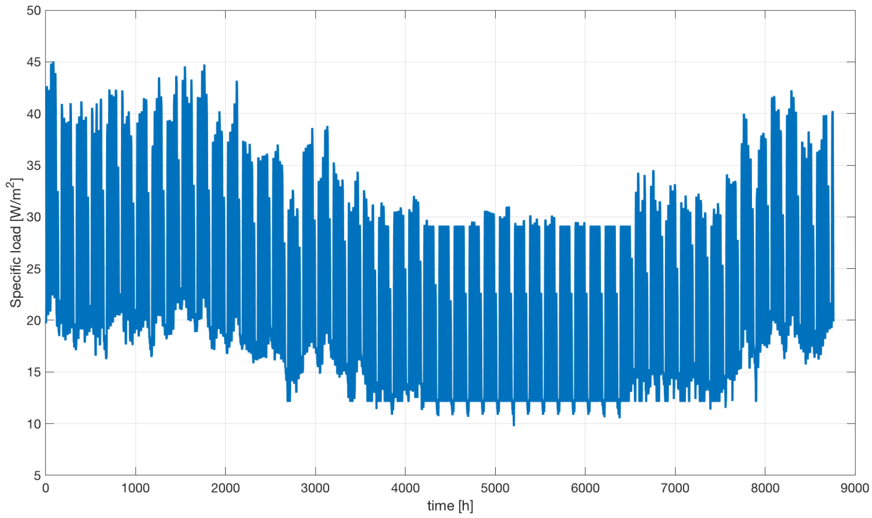


Figure 4.15: Shop cumulative load.

4.3 Meteorological data and RES production

In order to estimate PV and wind power productions, meteorological data from PVGIS are extracted: the most recent Typical Meteorological Year (TMY) dataset (2007-2016) is adopted. PVGIS online tool allows to elaborate yearly profile of several meteorological variables (e.g. temperature, wind speed, solar radiation) creating a reference year with the most representative months in the last decade. More in detail, for wind power estimation a 3 columns CSV file is extracted including ambient temperature at 2 m height, wind speed at 10 m height and ambient pressure, while for PV power assessment a multiple steps procedure is implemented. In order to properly take into consideration the albedo effect, which in case of snow covered surfaces can deeply impact PV production, the total solar radiation on sloped surface is extracted directly from PVGIS since it is obtained from satellite measurements. Namely, firstly the optimized slope and azimuth angles are evaluated, then using this configuration the total solar radiation on PV plane is extracted for the decade 2007-2016. Therefore, by using the same refence year composition of wind power data, the yearly profile of total solar radiation is obtained.
After evaluating wind resource, a commercial model of wind turbine able to withstand harsh environmental conditions (i.e. ice formation, extreme wind speed, saltness effect) has to be selected. [37] [33] For these reasons, WES80 wind turbine provided by Wind Energy Solutions BV is assumed as the reference model to be installed. According to IEC Wind Classes, WES80 turbine is classified as II class (medium wind) and it can stand up to 60 m/s windstorm. In addition, it can operate with an ambient temperature up to 20 degrees below zero. The technical specifications extracted from manufacturer data-sheet are summarized in Table 4.2.

Table 4.2: Wind turbine technical specification

Parameter	**Value**
$P_{rated}[kW]$	80
Cut-in wind speed [m/s]	3
Cut-out [m/s]	25
Rated speed [m/s]	13
Survival speed [m/s]	60
Tower height [m/	30
Rotor diameter[m]	18
Operating temperature [°C]	-20∼+40
Expected life-time [years]	20

In Figure 4.16 the reference wind turbine power curve is depicted. The plot shows the power produced by the turbine as a function of wind speed in reference conditions: namely, ambient temperature equal to 15 °C and ambient pressure of 101325 Pa, with a corresponding air density equal to 1.225 kg/m^3.

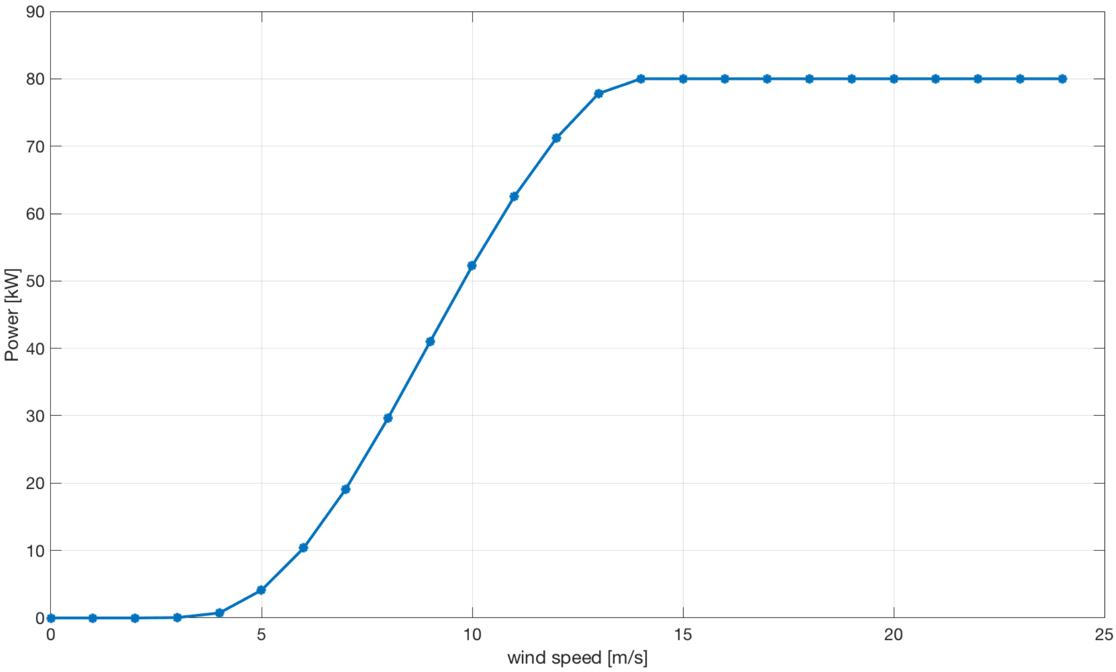


Figure 4.16: WES 80 power curve.

In order to evaluate wind turbine production by means of power curve in Figure 4.16, wind speed at the hub height has to be used. Wind speed extracted from PVGIS is available at 10 m height, thus this value has to be suitably corrected; in this case, a power law variation is applied:

$$u_{wind,hub} = u_{wind,anem} \cdot \left(\frac{h_{hub}}{h_{anem}} \right)^{\alpha} \tag{4.2}$$

It is necessary to note that α value can be set equal to 1/7 in case of flat surface. [57]

In the data-sheet, the power curve is provided only for discrete wind speed values, thus by processing these figures the following formulation is obtained:

$$P_{wind,std} = \begin{cases} 0 & \text{if } u_{wind,hub} < \textit{cut-in} \\ \text{Polynomial interpolation} & \text{if } \textit{cut-in} \leq u_{wind,hub} < \textit{rated} \\ P_{rated} & \text{if } \textit{rated} \leq u_{wind,hub} < \textit{cut-out} \\ 0 & \text{if } u_{wind,hub} \geq \textit{cut-out} \end{cases} \tag{4.3}$$

It is necessary to stress that the power curve equation provides the power output in reference conditions but, especially in the locations under investigations, the ambient temperature effects has to be included. In fact, the lower the ambient temperature, the higher the air density and therefore the power production. In Equation 4.4, the adopted correction is shown:

$$P_{wind} = P_{wind,std} \cdot \left(\frac{\rho}{\rho_{ref}} \right) \tag{4.4}$$

The PV power production taking into consideration the effect of solar radiation and ambient temperature can be evaluated as:

$$P_{PV} = P_{PV,STC} \cdot \left(\frac{G_T}{G_{STC}} \right) \cdot [1 + \alpha_P \cdot (T_c - T_{STC})] \tag{4.5}$$

with T_{STC}=25 °C.
According to [57], the power balance for the PV array states that:

$$\tau\alpha \cdot G_T = \eta_c \cdot G_T + U_L \cdot (T_c - T_a) \tag{4.6}$$

Solving for T_c:

$$T_c = T_a + G_T \cdot \left(\frac{\tau\alpha}{U_L} \right) \cdot \left(1 - \frac{\eta_c}{\tau\alpha} \right) \tag{4.7}$$

The $(\frac{\tau\alpha}{U_L})$ term can be expressed as:

$$\left(\frac{\tau\alpha}{U_L} \right) = \left(\frac{T_{c,NOCT} - T_{a,NOCT}}{G_{T,NOCT}} \right) \tag{4.8}$$

with:

- T_{STC}=800 W/m^2;
- $T_{a,NOCT}$=20°C
- $\tau\alpha$=0.9

Thus:

$$T_c = T_a + G_T \cdot \left(\frac{T_{c,NOCT} - T_{a,NOCT}}{G_{T,NOCT}} \right) \cdot \left(1 - \frac{\eta_c}{\tau\alpha} \right) \tag{4.9}$$

Assuming that the PV array always works in maximum power point:

$$\eta_c = \eta_{mpp} \tag{4.10}$$

Thus:

$$T_c = T_a + G_T \cdot \left(\frac{T_{c,NOCT} - T_{a,NOCT}}{G_{T,NOCT}}\right) \cdot \left(1 - \frac{\eta_{mpp}}{\tau\alpha}\right) \tag{4.11}$$

It is necessary to note that also η_{mpp} depends on cell temperature according to the following equation:

$$\eta_{mpp} = \eta_{mpp,STC} \cdot [1 + \alpha_P \cdot (T_c - T_{STC})] \tag{4.12}$$

Thus:

$$T_c = \frac{T_a + (T_{c,NOCT} - T_{a,NOCT}) \cdot \left(\frac{G_T}{G_{T,NOCT}}\right) \cdot \left[1 - \frac{\eta_{mpp,STC} \cdot (1 - \alpha_p \cdot T_{c,STC})}{\tau\alpha}\right]}{1 + (T_{c,NOCT} - T_{a,NOCT}) \cdot \left(\frac{G_T}{G_{T,NOCT}}\right) \cdot \left(\frac{\alpha_p \cdot \eta_{mpp,STC}}{\tau\alpha}\right)} \tag{4.13}$$

In the above equation, the temperatures must be expressed in Kelvin.

After estimating the solar resource and developing a model to evaluate the PV power production, a commercial PV panel has to be selected. A 365 W_{peak} PV panel provided by LG is assumed to be installed.
The LG365Q1C-A5 technical specifications are summarized in Table 4.3.

Table 4.3: PV technical specification

Parameter	**Value**
Cell type	Monocrystalline silicon
P_{rated} [W]	365
η_c [-]	0.21
NOCT [°C]	44±3
α_p [%/°C]	-0.3
Operating temperature [°C]	-40 ∼+90

4.4 Sizing procedure and economic analysis

After estimating load profile and assessing RES production, the Power-to-Power system has to be sized. In order to carry out the sizing procedure, a techno-economic optimization tool implemented as part of REMOTE project is adopted.
Local renewables and energy storage are required to met electric load reducing (or even completely avoiding) external sources. In P2P system, renewable power surplus can be stored in battery or in form of hydrogen (produced by water electrolysis) whereas power shortage has to be covered by battery discharge or electricity

production in hydrogen-fed fuel cell. A schematic of P2P system is shown in Figure 4.17.
In case of hybrid-P2P systems, two different storage solutions are exploited: battery for short-term storage and hydrogen for long-term one. Due to the system complexity, a proper Energy Management System (EMS) is developed during REMOTE project activities. [23]. Basing on EMS strategy, battery system has priority of operation and its state of charge (SOC) represents the *«main decision factor for the EMS»*, as stated by Marocco et al. in [23]. Therefore, maximum and minimum battery SOC determines the operation of fuel cell and electrolyzer: in fact, if during charging phase maximum battery SOC is reached, electrolyzer switches on and starts producing hydrogen while if during discharging phase minimum SOC is achieved, fuel cell turns on. Even Level of Hydrogen (LOH) has to be monitored: electrolyzer can operate until when hydrogen can be stored in H_2 tank and fuel cell can work if the required amount of hydrogen is available. Finally, also modulation of electrochemical devices have to be kept in a range such to ensure correct operation. The input parameters of EMS are summarized in Table 4.4. [23]

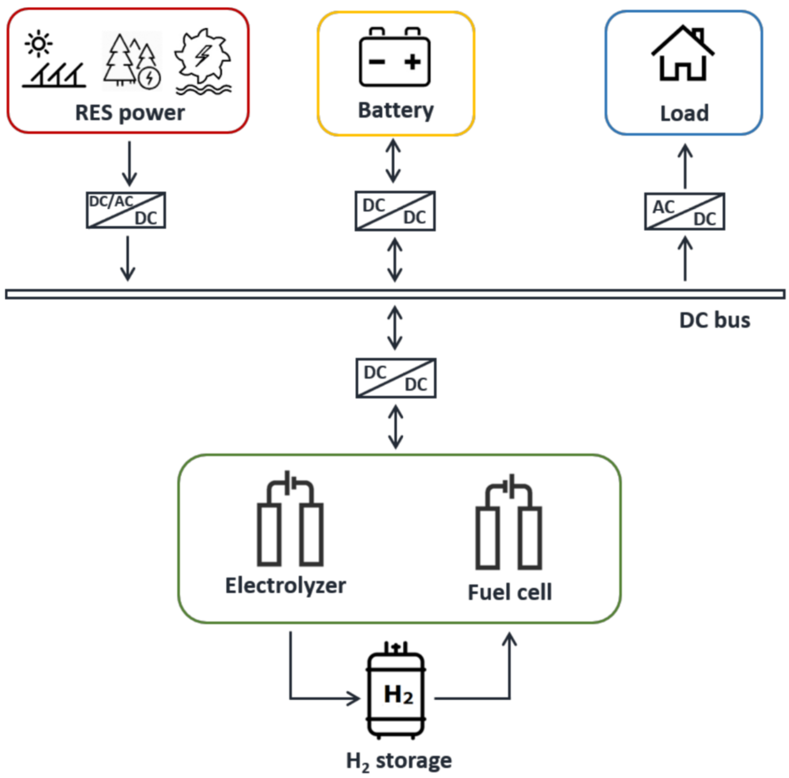


Figure 4.17: Power-to-Power system layout. [63]

Table 4.4: EMS input parameters.

Component	Parameter	Value
Battery	SOC min	0.2
	SOC max	1
Fuel cell	modulation range	0.06-1
Electrolyzer	modulation range	0.1-1
H2 tank	p_{min}	3 bar
	p_{max}	28 bar
	SOC min	p_{min}/p_{max}
	SOC max	1

In Table 4.5 the efficiencies of hybrid-P2P system components are listed.

Table 4.5: Components efficiency.

Component	Value
Fuel cell	0.471
Electrolyzer	0.58
Battery	0.95 (charging)
	0.95 (discharging)

Analysing in detail EMS strategy proposed in [23], two possible situations are identified:

- **RES>Load:** if RES power exceeds electric load, the surplus is firstly used to charge battery; when maximum SOC is reached, electrolyzer working in its modulation range and driven by RES surplus starts to produce hydrogen until completely filling storage tank. If still present, the remaining surplus is curtailed. The charging phase is depicted in Figure 4.18.
- **Load>RES:** if the load exceeds RES production, energy stored in battery or hydrogen tank has to be used to cover the power deficit. Basing on battery SOC, the most suitable solution is adopted: firstly the shortage is covered by battery, but if minimum SOC is reached fuel cell switches on. Fuel cell can work within its modulation range and if a sufficient amount of hydrogen is stored in the tank. If electric load to be covered is lower than the minimum allowed fuel cell power, EMS forces fuel cell to work at its minimum power; in this case, the remaining fuel cell power is used to charge battery (if possible) or it is curtailed. The discharging phase is shown in Figure 4.19.

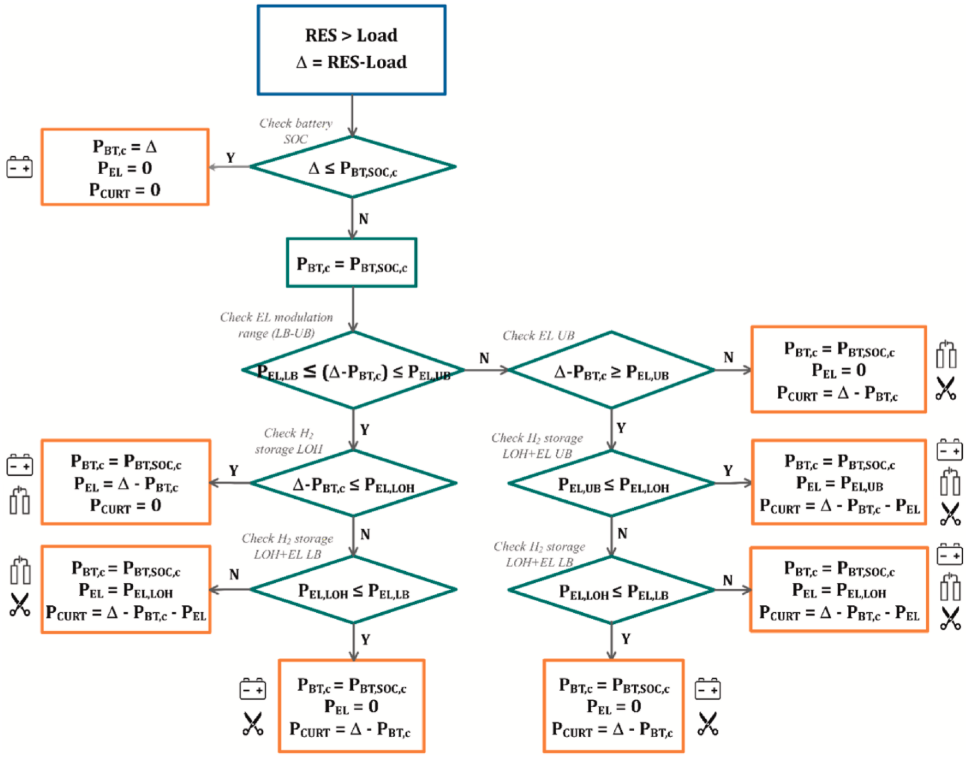


Figure 4.18: EMS strategy in case of surplus. [23]

The techno-economic optimization tool includes the EMS model and it is based on Particle Swarm Optimization (PSO) algorithm, a meta-heuristic method that allows to explore very large search-spaces in order to determine the optimal solution. The algorithm relies on a population (the so-called swarm) of possible solutions (i.e. particles) that move around the search-space basing on information related to their own best position and that of the whole swarm.
The objective function of the optimization method is the minimization of the LCOE of the system, while the constrains to be satisfied are:

- $LPSP \leq LPSP_{target}$
- $S_{i,min} \leq S_i \leq S_{i,max}$

The Loss of Power Supply Probability (LPSP) represents an evaluation criterion for the reliability of the off-grid system: namely, it indicates the number of hours per year in which electric load is not met by the supply system. Therefore, it is defined as:

$$LPSP = \frac{\sum_{i=1}^{8760} P_{deficit}(t) \cdot \Delta t}{\sum_{i=1}^{8760} P_{load}(t) \cdot \Delta t} \tag{4.14}$$

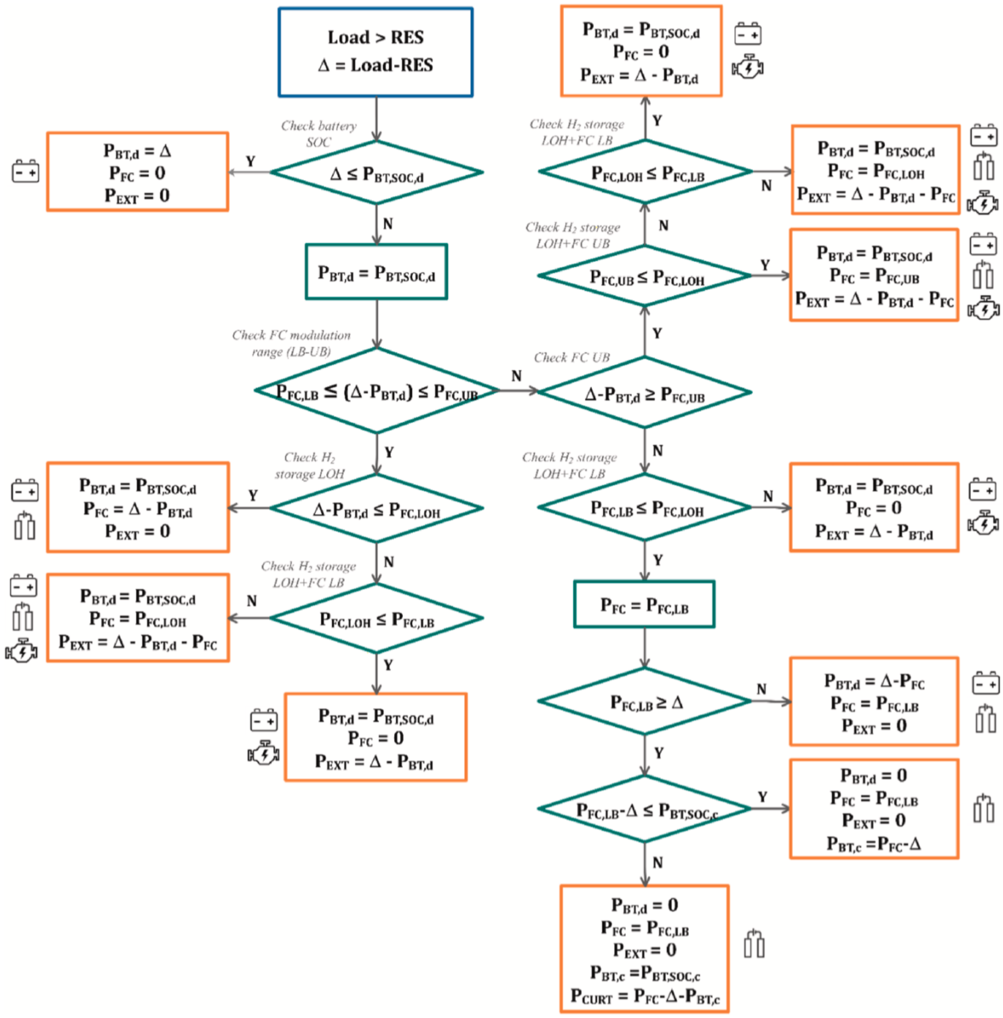


Figure 4.19: EMS strategy in case of deficit. [23]

By definition, LPSP ranges between 0 and 1: the lower bound implies that the load is always satisfied, while the upper one indicates that the load is never met. In literature, wide range of LPSP are investigated (e.g. from 0 to 5% in [64]) but in general, reliable off-grid systems are characterized by LPSP lower than 1%.
In this case LPSP target value is set to 0: namely, the system is designed in order to reach complete autonomy and ensure continuous load supply.
The tool provides in output the sizes of the components and the corresponding LCOE. In order to achieve these outcomes, a detailed techno-economic analysis of P2P system is carried out at each algorithm iteration until reaching the optimum configuration. LCOE assessment requires the evaluation of discounted cash-flows and total energy production during the whole lifetime of the system.

Thus, LCOE is defined as:

$$LCOE = \frac{CAPEX + \sum_{i=1}^{N}\left(\frac{O\&M_j}{(1+c)^j} + \frac{RC_j}{(1+c)^j}\right)}{\sum_{i=1}^{N}\left(\frac{Energy_j}{(1+c)^j}\right)} \tag{4.15}$$

with:

- $CAPEX$: capital expenditure;
- $O\&M$: operation and maintenance cost;
- RC: replacement cost;
- N: plant lifetime;
- c: real interest rate;

CAPEX represents the investment cost (including transport and installation) that is incurred at the beginning of the analysis (i.e. i=0). OPEX accounts for the cost incurred for running and maintaining the plant from the beginning to the end of its lifetime: namely, it includes operational and general maintenance costs and replacement expenditure. CAPEX, OPEX and lifetime of plant components adopted by Marocco et al. in [23] are summarized in Table 4.6. As can be noted, PV modules, wind turbines and hydrogen storage lifetimes are assumed equal to plant lifespan while fuel cell, electrolyzer and battery replacement time are derived from the simulation: namely, they are evaluated on the basis of yearly operating hours and number of startups.
In order to evaluate discounted cash-flows, an interest rate is required: taking into consideration the effect of inflation, real interest rate has to be used. Nominal interest rate can be expressed as a function of real interest and inflation rates according to the following equation :

$$i = (1 + c) \cdot (1 + e_i) - 1 \tag{4.16}$$

whit:

- i: nominal interest rate;
- c: real interest rate;
- e_i: inflation rate;

Table 4.6: CAPEX, OPEX and lifetime

Component	CAPEX		OPEX		Lifetime
PV	PV panels transport and installation	1133.33 €/kW 320 €/kW	PV replacement transport and installation O&M	680 €/kW 360 €/kW 320 €/kW·y	plant lifetime
Wind	Wind turbine	1175 €/kW	Replacement O&M	723 €/kW 3% of CAPEX/year	plant lifetime
Fuel cell	Reference size Reference specific cost 100 units Reference cost Cost exponent	10 kW 4381 $/kWh 39827.27 € 0.7	Replacement O&M	26.7% of CAPEX 3% of CAPEX/year	by simulation
Electrolyzer	Reference size Reference specific cost Reference cost Cost exponent	50 kW 4600 €/kW 230000 € 0.65	Replacement O&M	26.7% of CAPEX 4% of CAPEX/year	by simulation
Hydrogen storage	H_2 tank	470 €/kg	Replacement O%M	470 €/kg 2% of CAPEX/year	plant lifetime
Battery	Battery	550 €/kWh	Replacement O%M	350 €/kWh 10 €/kWh·y	by simulation
Converters	Inverter	93.33 €/kW	Replacement O%M	80 €/kW 4% of CAPEX/year	10 y

thus:

$$c = \frac{i - e_i}{1 + e_i} \tag{4.17}$$

Assuming the values reported in Table 4.7, the real interest rate results in 4.9%.

Table 4.7: Interest rates and inflation.

Parameter	**Value**
Nominal interest rate	7%
Inflation rate	2%

It is necessary to highlight that the economic analysis is carried out with a time-horizon of 20 years.

4.5 Sea cable and diesel generator

After evaluating LCOE of P2P system (in both *only-battery* and *battery-hydrogen* configurations), alternative electrification solutions are analysed. In particular, techno-economic and environmental feasibilities of sea cable and diesel generators installation are investigated. LCOE is determined for both solutions and yearly CO_2 emissions are estimated for the diesel scenario.
In order to evaluate sea cable and diesel generator LCOE, investment and operating costs have to be assessed.
In case of sea cable scenario, CAPEX is estimated on the basis of specific information provided by REMOTE project partner. Due to confidentiality reasons, detail outcomes are omitted in the present work; however, it is possible to state that basing on project data, capital expenditure is properly scaled depending on sea cable length. As regards operating cost, $O\&M$ is assumed to be a fixed percentage of CAPEX while the electricity cost contribution takes into account the operating conditions: namely, electricity can be provided by national grid (with a certain price) or can be locally produced by backup systems. In fact, due to outages and maintenance activities, only 95% of yearly load is assumed to be covered by sea cable and the remaining 5% is supposed to be met by diesel generator (that only provides backup function).
Thus, sea cable LCOE can be evaluated as:

$$LCOE_{SC} = \frac{CAPEX_{SC} + \sum_{i=1}^{N} \left(\frac{O\&M_j}{(1+c)^j} + \frac{E_{grid} \cdot C_{e,grid}}{(1+c)^j} + \frac{E_{back-up} \cdot C_{e,back-up}}{(1+c)^j} \right)}{\sum_{i=1}^{N} \left(\frac{E_j}{(1+c)^j} \right)} \tag{4.18}$$

In case of diesel scenario, CAPEX and OPEX are estimated according to [23]. Investment, operating, replacement costs and lifetime are summarized in Table 4.8.

Table 4.8: Diesel cost and lifetime.

Parameter	**Value**
Investment cost	420 €/kW
Replacement cost	420 €/kW
O&M	0.4 €/h+2 €/litre
Lifetime	16000 h

According to [23], in order to properly evaluate diesel consumption (i.e taking into consideration the effect of the actual operating point with respect to nominal size), a linear function of fuel consumption and output power is considered:

$$cons_{DG} = A \cdot P_{DG} + B \cdot P_{DG,rated} \tag{4.19}$$

with:

- A=0.246 litre/kWh
- B=0.08415 litre/kWh

Thus, diesel LCOE can be evaluated as:

$$LCOE_{DG} = \frac{CAPEX_{DG} + \sum_{i=1}^{N}\left(\frac{O\&M_j}{(1+c)^j} + \frac{RC_j}{(1+c)^j}\right)}{\sum_{i=1}^{N}\left(\frac{Energy_j}{(1+c)^j}\right)} \tag{4.20}$$

Diesel generator size is determined on the basis of peak load demand; however, it is necessary to note that if the rated power results larger than 100 kW, two separate units are installed, each of them with a nominal power equal to half of the total required power. This solution is adopted to avoid diesel generators working at partial load: if possible, one unit operates in nominal conditions and the other covers the remaining part. Moreover, diesel generator can adjust its output power in the range 0.3-1 (as a fraction of rated power); therefore, if the required power is lower than 30% of rated value, the device is forced to work at its minimum allowable load and the excess power is curtailed.
After determining fuel consumption, CO_2 emissions can be evaluated. In general, the consumption of one litre diesel emits 2.7 kg of CO_2 but, it is necessary to note that both carbon content and CO_2 production depend on fuel characteristics

and diesel generator technical specifications; in fact, emission factors in the range 2.4-3.5 kg/litre can be found in literature. Therefore, according to Jakhrani et al. in [65], an average emission factor equal to 3 kg/litre can be assumed in the analysis.

Chapter 5

Description of case studies

In this chapter the detailed techno-economic analysis of the 12 selected islands is carried out. For each island, a general description is provided including geographical location, meteorological information, population data, community services and current electrification system. After determining the total electric load, renewable production is assessed and the outcomes of sizing procedure are discussed. In the H2-battery scenario, relevant energy balances are evaluated: in case of Støttvær island these results are discuss in detail, while for other islands they are reported in Appendix A. Finally, alternative scenarios are analysed and the different LCOE are compared.

5.1 Støttvær island

Støttvær is an island in Meløy municipality, Nordland county. Basing on the most recent data (2017), Støttvær has 27 permanent inhabitants. The island is located about 3 km far from the mainland and it is served by sea cable connection: a 2.8 km cable (22kV) has been in operation since 1991. Islands does not provide community services and even if it hosts few summer houses only permanent population is considered.

Although its high-latitude location, Støttvær does not experience extreme weather conditions: ambient temperature ranges between -3 °C in February and almost 20 °C in August, with an annual average value of 8.64 °C.

As regards wind potential, island exhibits a good resource during winter months (with peaks of 15 m/s) but it reduces in summer (as typical of northern locations); therefore, yearly average wind speed at 10 m height results around 5.1 m/s.

As concerns solar potential, high latitude determines strong seasonal variations: solar resource is quite limited in autumn and winter months while it reaches its maximum during May and June.

Figure 5.1: Støttvær location (modified from [47]).

5.1.1 Electric load

On the basis of population data, residential electric load of Støttvær is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Støttvær's building stock consists of 7 houses. Yearly energy consumption results in 156 386 kWh/y with a peak demand of 44.2 kW. Støttvær electric load information are summarized in Table 5.1.

Table 5.1: Støttvær population and electric load data.

Parameter	Value
Population	27
Houses	7
Yearly energy consumption [kWh/y]	156 386
Peak demand [kW]	44.2

In Figure 5.2 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

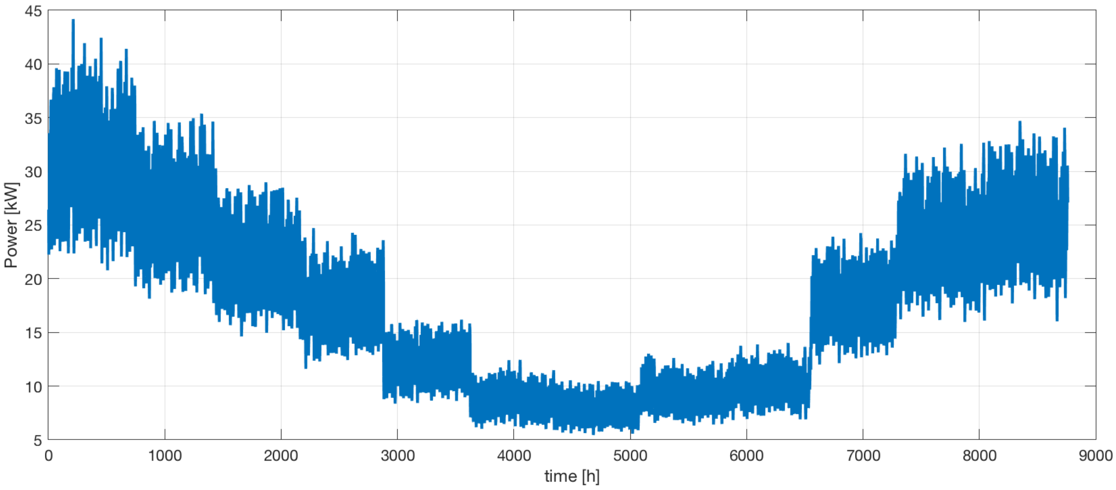


Figure 5.2: Støttvær electric load.

5.1.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Ambient temperature and wind speed hourly value are shown in Figure 5.3.
In order to evaluate solar radiation incident on PV surface, optimal values of tilt angle (β) and azimuth angle (γ) are to be determined. Optimized value of inclination and orientation are summarized in Table 5.2: tilt angle turns out to be considerably high (as typical of northern locations) while azimuth results near south direction(as frequently occurs).
In Figure 5.4 hourly values of solar radiation are shown. As anticipated, solar resource exhibits strong seasonal variation mainly due to the limited length of the day during winter months.

Table 5.2: Optimal tilt and azimuth angle.

Angle	**Value**
Tilt angle β [°]	50
Azimuth angle γ [°]	1

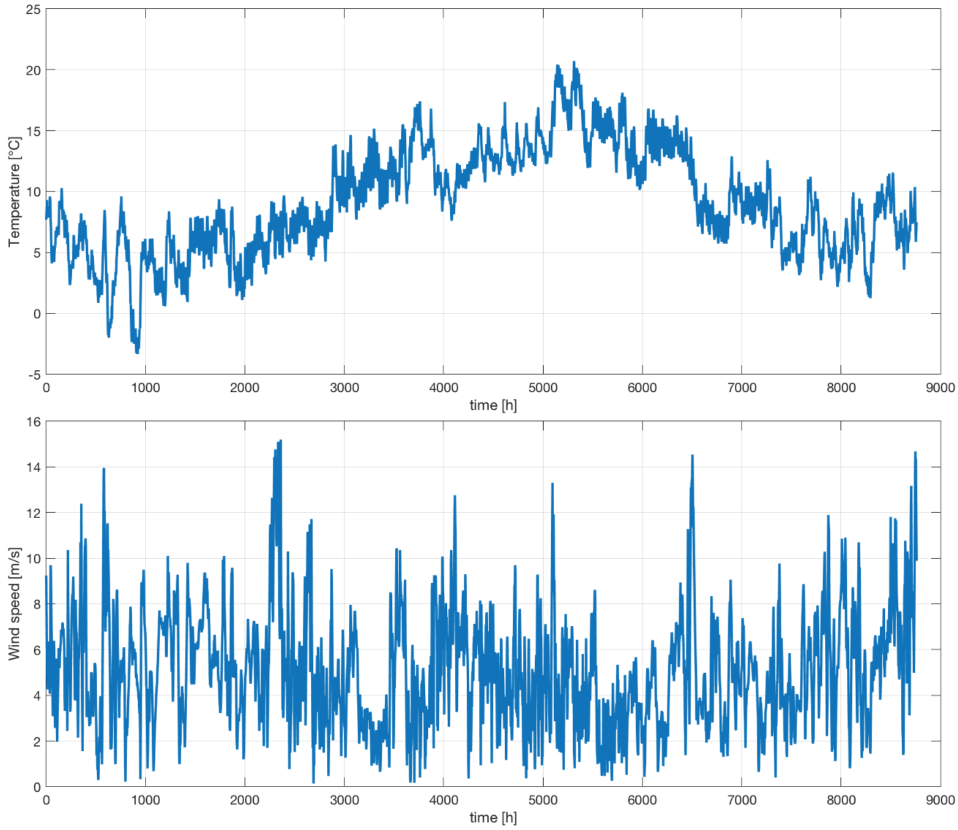


Figure 5.3: Støttvær temperature and wind speed profile.

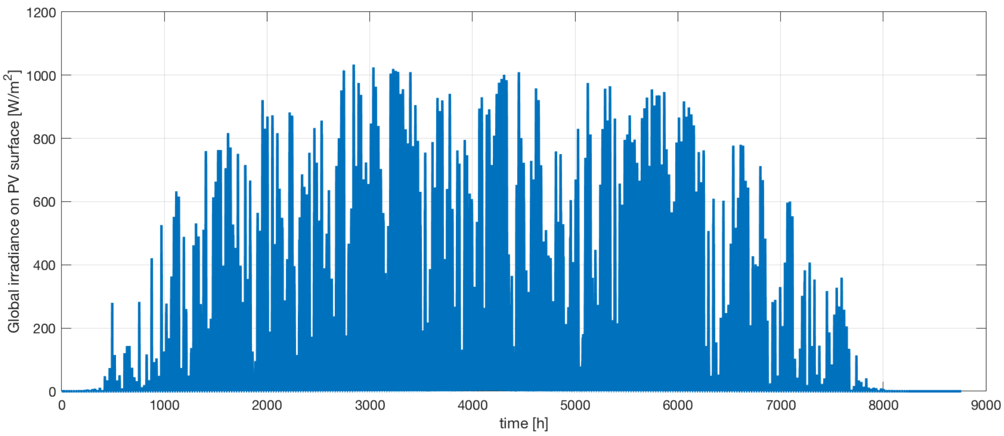


Figure 5.4: TMY solar radiation with optimal β and γ.

Assuming wind turbine and PV panel technical specifications and performances listed in 4.3, renewable energy sources production is assessed. In Figure 5.5 wind and PV power produced respectively by 80 kW turbine and 365 W solar panel are shown.

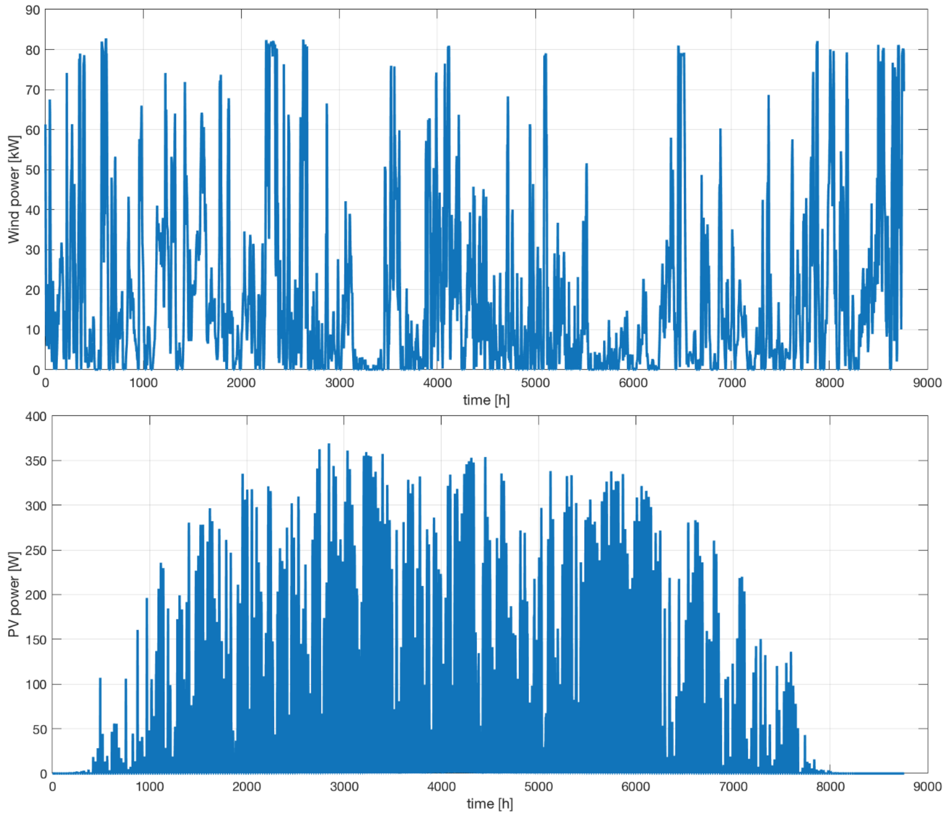


Figure 5.5: Støttvær wind and PV power production.

5.1.3 Sizing procedure and economic analysis

Electric load profile and specific RES power production (i.e. produced power normalized with respect to installed capacity) are provided as input data to the techno-economic optimization tool. The code produces as output the sizes of the components and the corresponding LCOE according to the assumptions and the procedure described in Section 4.4.
Two different configurations are analysed and evaluated: hybrid H2-battery P2P systems and only-battery scheme. The outcomes of both strategies are assessed and commented separately.

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The results of sizing procedure are summarized in Table 5.3.

Table 5.3: Hybrid P2P configuration.

Component	Size
PV [kW]	3
Wind [kW]	341
Fuel cell [kW]	40
Electrolyzer [kW]	53
Hydrogen [kWh]	6433
Battery [kWh]	116

When comparing wind and PV sizes, the latter turns out to be significantly lower; this occurs because the limited availability of solar resource (in particular during winter) does not make economically feasible the installation of a larger capacity. Consequently, the wide difference in installed power is reflected in energy production, as is evident in Table 5.4. Therefore, on Støttvær island renewable energy is almost completely produced by wind.

Table 5.4: RES energy production.

RES	Value
PV production [kWh]	3144.5
Wind production [kWh]	642 944

From the analysis of RES and load energy balance, it is clear that monthly RES production far exceeds energy demand, especially during winter season (in which, although the load is higher, wind resource is abundant) as can be noted in Figure 5.6. However, in order to deeply understand RES and load coupling, surplus and deficit energy balance is required to be analysed. In fact, although RES exceeds load on a monthly basis, for a certain number of hours energy consumption is higher than PV and wind production, as shown in Figure 5.7.

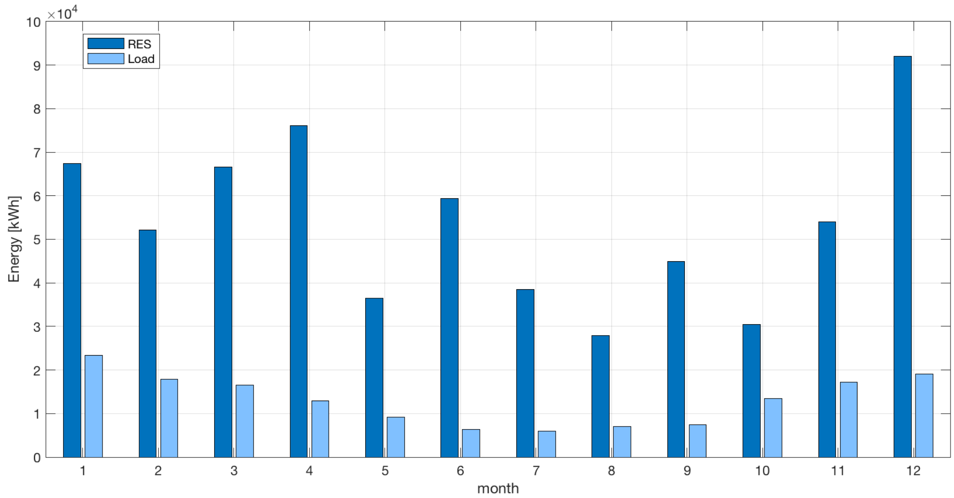


Figure 5.6: RES and load energy balance.

It is necessary to highlight that RES surplus is considerably larger than deficit (i.e. more than 10 times in some months); therefore by means of energy storage system, excess renewable power can be stored and exploited to cover the load demand when shortage occurs. As can be noted in Figure 5.7, in Støttvær surplus does not exhibit a remarkable seasonal pattern while, in general, deficit results higher during cold months.
According to EMS control strategy described in Section 4.4, electric load can be met directly by RES or by storage system units (either battery or fuel cell). Post-processing yearly simulation results, a detail segmentation of load supply can be determined: in Figure 5.8 the fraction of load covered respectively by renewable power, battery discharging phase and fuel cell operation is highlighted.

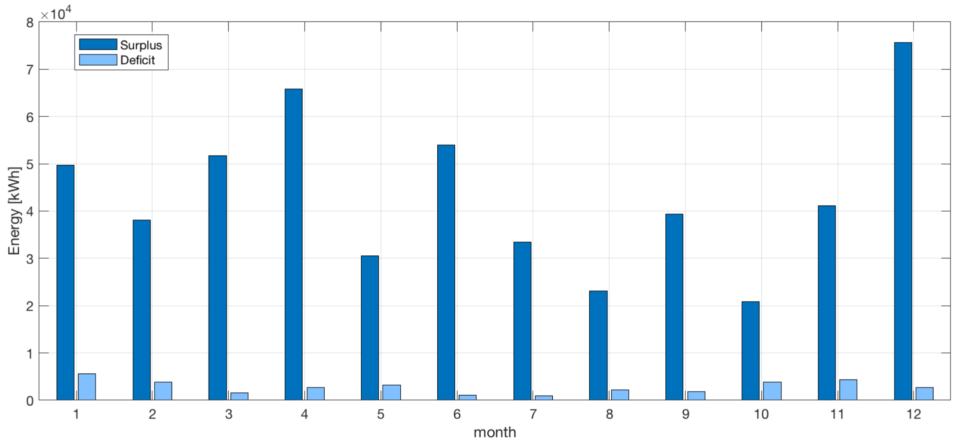


Figure 5.7: Surplus and deficit energy balance.

As evident, a significant share of energy requirement is fulfilled by RES power (mainly wind, as stated before), followed by fuel cell fraction and finally by battery contribution.

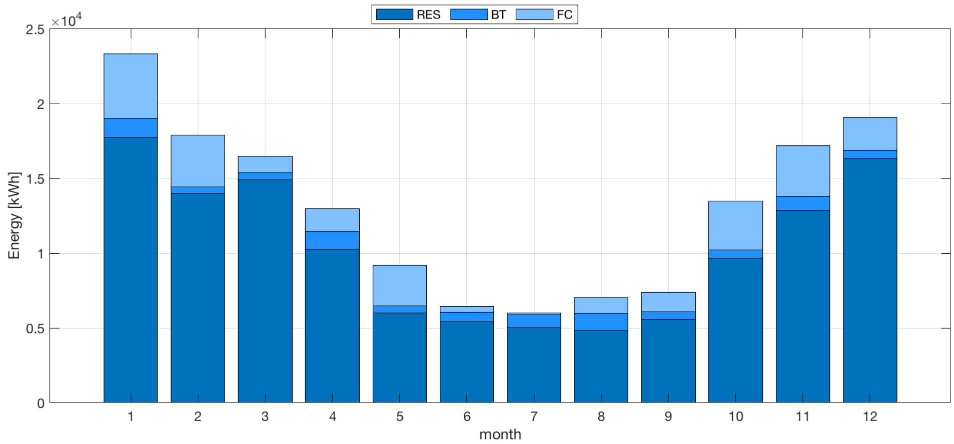


Figure 5.8: Load supply segmentation.

In Figure 5.9 renewable production breakdown is shown: as stated before, a considerable amount of RES power directly covers electric load and, especially during winter, renewable electricity drives electrolyzer operation; in addition, it can be noted that only a small fraction of RES generation charges the battery system. Finally, it is necessary to highlight that a remarkable percentage of renewable is curtailed: it occurs both during winter (when the production is higher) and summer (when the load is lower and storage is completely full).

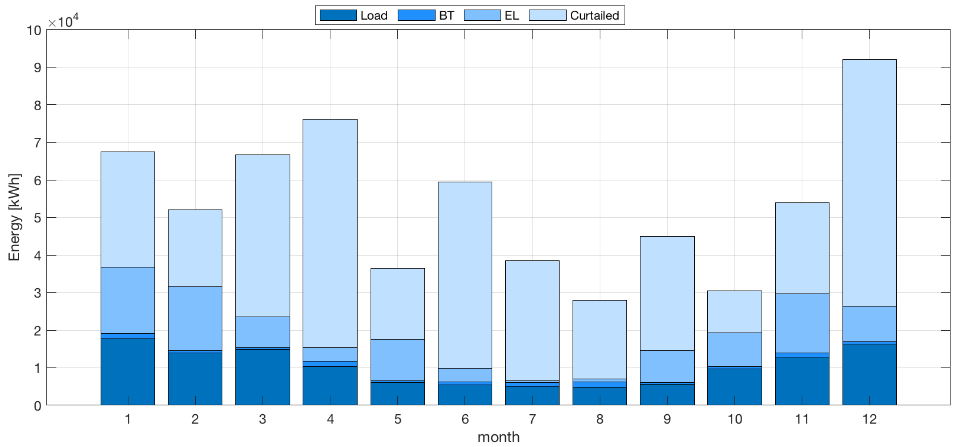


Figure 5.9: Storage and curtailment.

In order to understand in detail the causes of power curtailment, it is necessary to analyse the LOH evolution during the whole year and compare it with surplus and deficit profiles. Obviously, when excess power is available but hydrogen tank is full (LOH=1) energy storage can not be realized and curtailment is required, as is evident in Figure 5.10.

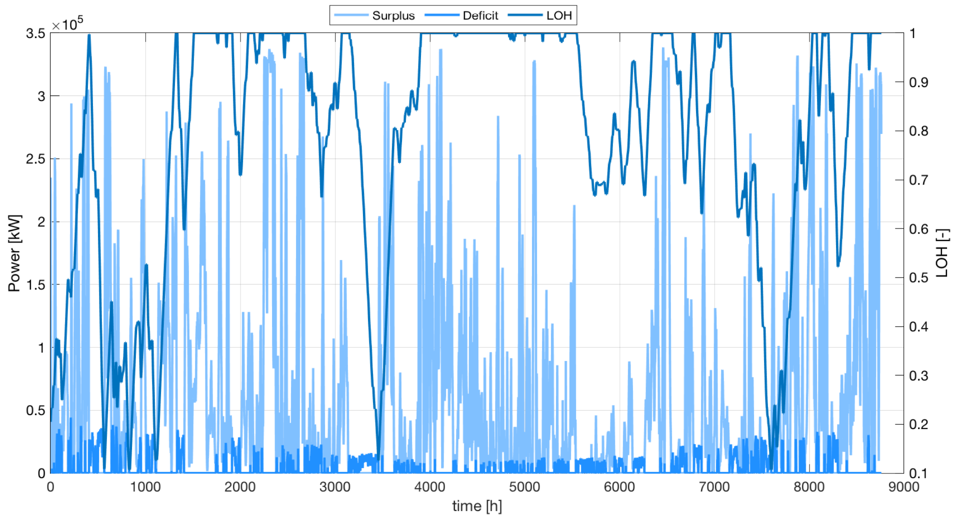


Figure 5.10: Surplus, deficit and LOH.

In hybrid P2P system configuration, the NPC results in 1 230 092 € and the total provided energy (discounted value) is 1 965 220 kWh; therefore, LCOE turns out to be 0.63 €/kWh. Detailed cost items description and the contribution of each component to LCOE are shown respectively in Table 5.5 and Figure 5.11.

Table 5.5: NPC cost items description.

Component	**Cost [€]**
PV	4849
Wind	552 400
Fuel cell	142 729
Electrolyzer	338 023
Hydrogen	113 538
Battery	78 552

As can be noted in Figure 5.11, the main contributions to LCOE are related to wind turbine and hydrogen storage unit (i.e electrolyzer, fuel cell and tank), while PV and battery have lower impact.

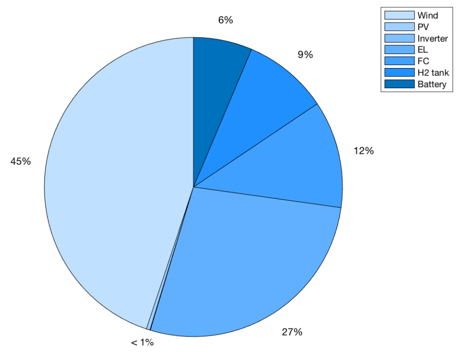


Figure 5.11: Breakdown cost.

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.66 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.6. As can be noted, the sizes of PV and wind plants are considerably larger than those of H2-battery scenario: namely, the system has to be oversized in order to ensure load supply. In addition, even battery storage results much larger since it represents the only storage solution.

Table 5.6: Only-battery configuration.

Component	**Size**	**NPC**
PV	10 kW	16 880 €
Wind	486 kW	785 921 €
Battery	2245 kWh	1 516 922 €

For these reasons, the NPC is quite high (i.e. 2 321 636 €) and the corresponding LCOE is 1.18 €/kWh.

5.1.4 Alternative scenarios and LCOE comparison

As discussed in Section 4.5, two alternative scenarios are analysed: the existing sea cable substitution and the installation of diesel generator.
In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.35 €/kWh.

In the diesel scenario, a 45 kW generator is assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.7. In this case, LCOE results in 1.04 €/kWh.

Table 5.7: Diesel scenario.

Parameter	**Value**
Rated power [kW]	45
Yearly fuel consumption [l/y]	75 051
Yearly CO_2 emissions [ton/y]	225.15

In Table 5.8 the LCOE of the different scenarios for Støttvær island are collected.

Table 5.8: LCOE comparison.

Scenario	**LCOE [€/kWh]**
H2-battery	0.63
Only-hydrogen	0.66
Only-battery	1.18
Sea cable	0.35
Diesel	1.04

5.2 Linesøya island

Linesøya is an island in Åfjord municipality, Trøndelag county. Basing on the most recent data (2019), Linesøya has 77 permanent inhabitants. The island lies about 3 km far from the mainland and it is served by sea cable connection: a 3.8 km cable (22kV) has been in operation since 1980. Islands does not provide community services and even if can host few summer houses, only permanent population is considered.

Linesøya experiences extreme weather conditions: ambient temperature reaches almost -20 °C in February and during winter it is usually below zero; in summer months the temperature is frequently above 10 °C (it grazes 20 °C in August). Therefore, the annual average value is 6.81 °C.

As regards wind potential, island exhibits a good resource during winter months (with peaks of 14 m/s) but it reduces in summer (as typical of northern locations); therefore, yearly average wind speed at 10 m height results around 4.36 m/s.

As concerns solar potential, the radiation has a strong seasonal pattern: resource is quite limited in autumn and winter months while it reaches its maximum during May and June.

Figure 5.12: Linesøya location (modified from [47]).

5.2.1 Electric load

On the basis of population data, residential electric load of Linesøya is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Linesøya's building stock consists of 19 houses. Yearly energy consumption results in 425 777 kWh/y with a peak demand of 113.4 kW. Linesøya electric load information are summarized in Table 5.9.

Table 5.9: Linesøya population and electric load data.

Parameter	**Value**
Population	77
Houses	19
Yearly energy consumption [kWh/y]	425 777
Peak demand [kW]	113.4

In Figure 5.13 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

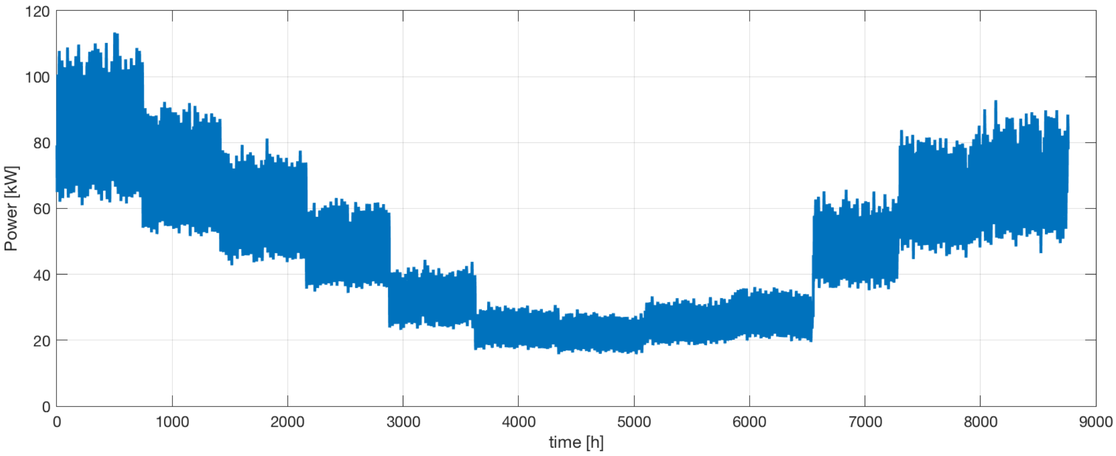


Figure 5.13: Linesøya electric load.

5.2.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.1a, A.1b and A.1c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.1, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.2.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.10. LCOE results in 0.59 €/kWh; a detailed breakdown cost can be observed in Figure A.12a.
As can be noted in Table 5.10, main cost contributions are related to wind turbine and hydrogen unit; in this case, the solar resource availability makes economically convenient the installation of a significant PV capacity.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.1.

Table 5.10: Hybrid P2P configuration.

Component	Size	NPC
PV	87 kW	148 485 €
Wind	812 kW	1 314 044 €
Fuel cell	115 kW	298 083 €
Electrolyzer	198 kW	777 876 €
Hydrogen	16 877 kWh	297 865 €
Battery	421 kWh	284 378 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.63 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.11.

Table 5.11: Only-battery configuration.

Component	Size	NPC
PV	162 kW	275 467 €
Wind	1114 kW	1 801 893 €
Battery	4091 kWh	2 763 877 €

In case of only-battery scenario, both RES and storage unit sizes result considerably larger: namely, the plant has to be oversized in order to ensure load supply. This aspect clearly impacts on NPC, as can be noted in Table 5.11. LCOE turns out to be 0.91 €/kWh.

5.2.4 Alternative scenarios and LCOE comparison

In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.23 €/kWh.
In the diesel scenario, two 60 kW generators are assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.12. In this case, LCOE results in 0.92 €/kWh.

Table 5.12: Diesel scenario.

Parameter	Value
Rated power [kW]	2x60
Yearly fuel consumption [l/y]	167 707.4
Yearly CO_2 emissions [ton/y]	503.1

In Table 5.13 the LCOE of the different scenarios for Linesøya island are collected.

Table 5.13: LCOE comparison.

Scenario	LCOE [€/kWh]
H2-battery	0.59
Only-hydrogen	0.63
Only-battery	0.91
Sea cable	0.23
Diesel	0.92

5.3 Fjøløy island

Fjøløy is an island in Stavanger municipality, Rogaland county. Basing on the most recent data (2017), Fjøløy has 179 permanent inhabitants. The island is located about 5.2 km far from the mainland and according to NVE information it has a local grid without sea cable connection to national system. Islands does not provide community services and even if it hosts few summer houses only permanent population is considered. Due to its peculiar location (i.e. it is almost inside a fjord), Fjøløy does not experience severe weather conditions: ambient temperature ranges between -2 °C in January and almost 20 °C in June, with an annual average value of 8.55 °C. As regards wind potential, island exhibits a good resource during winter months (with peaks of 17.5 m/s) but it reduces in summer (as typical of northern locations); therefore, yearly average wind speed at 10 m height results around 5.1 m/s. As concerns solar potential, resource is quite limited in autumn and winter months while it reaches its maximum during May and June.

5.3.1 Electric load

On the basis of population data, residential electric load of Fjøløy is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Fjøløy's building stock

Figure 5.14: Fjøløy location (modified from [47]).

consists of 45 houses.
Yearly energy consumption results in 1 008 500 kWh/y with a peak demand of 257 kW. Fjøløy electric load information are summarized in Table 5.14.

Table 5.14: Fjøløy population and electric load data.

Parameter	**Value**
Population	179
Houses	45
Yearly energy consumption [kWh/y]	1 008 500
Peak demand [kW]	257

In Figure 5.15 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

5.3.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.2a, A.2b and A.2c.

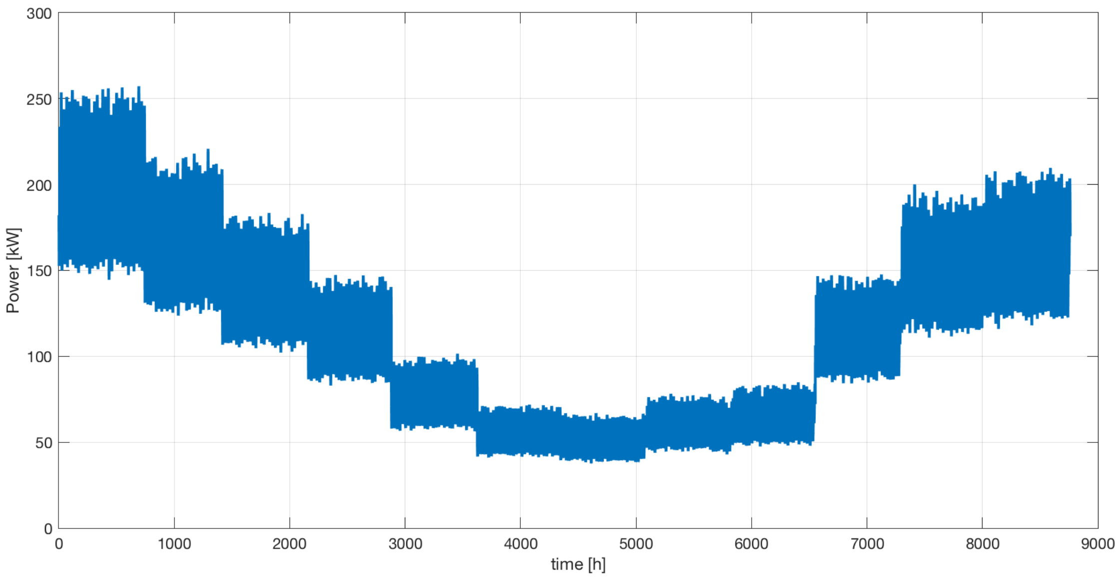


Figure 5.15: Fjøløy electric load.

Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.2, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.3.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.15. LCOE results in 0.82 €/kWh; a detailed breakdown cost can be observed in Figure A.12b.
As can be noted in Table 5.15, main cost contributions are related to hydrogen unit, followed by wind turbine and PV, in fact, in this case solar resource availability makes profitable the installation of a large PV capacity.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.2.

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.85 €/kWh.

Table 5.15: Hybrid P2P configuration.

Component	Size	NPC
PV	1189 kW	2 027 535 €
Wind	1120 kW	1 812 531 €
Fuel cell	268 kW	477 138 €
Electrolyzer	360 kW	1 156 894 €
Hydrogen	213 222 kWh	3 763 291 €
Battery	1285 kWh	868 474 €

Only-battery

The results of sizing procedure are summarized in Table 5.11. In case of only-battery scenario, both RES and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply; in particular, PV capacity almost quadruplicates, while wind slightly reduces. This aspect clearly impacts on NPC, as can be noted in Table 5.16. LCOE turns out to be 1.29 €/kWh.

Table 5.16: Only-battery configuration.

Component	Size	NPC
PV	4185 kW	7 134 029 €
Wind	623 kW	1 008 077 €
Battery	11 024 kWh	7 448 589 €

5.3.4 Alternative scenarios and LCOE comparison

In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.17 €/kWh.
In the diesel scenario, two 130 kW generators are assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.17. In this case, LCOE results in 0.90 €/kWh.

Table 5.17: Diesel scenario.

Parameter	**Value**
Rated power [kW]	2x130
Yearly fuel consumption [l/y]	393 458
Yearly CO_2 emissions [ton/y]	1180

In Table 5.18 the LCOE of the different scenarios for Fjøløy island are collected.

Table 5.18: LCOE comparison.

Scenario	**LCOE [€/kWh]**
H2-battery	0.82
Only-hydrogen	0.85
Only-battery	1.29
Sea cable	0.17
Diesel	0.90

5.4 Selvær island

Selvær is an island in Træna municipality, Nordland county. Basing on the most recent data (2018), Selvær has 55 permanent inhabitants; on the islands there is only a small shop serving local community.
The island lies in a very remote location: it is located almost 34 km far from the mainland and 10 km north-east of the main island of Husøya. Due to its open-water position, Selvær faces harsh environmental conditions: minimum temperature during winter reaches -12 °C and maximum in summer is around 18 °C; the annual average value results in 6.79 °C.
Island exhibits extremely profitable wind potential: namely, Selvær is characterized by an annual average wind speed of 7.76 m/s with peaks over 22 m/s during winter months. As concerns solar potential, radiation is quite limited in autumn and winter months while it reaches its maximum during May and June.
According to NVE information, island has a local grid without sea cable connection to national system.

Figure 5.16: Selvær location (modified from [47]).

5.4.1 Electric load

On the basis of population data, residential electric load of Selvær is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Selvær's building stock consists of 14 houses. After cartographic evaluation, the shop floor area is assumed equal to 140 m^2. Therefore, the yearly energy consumption results in 345 976 kWh/y with a peak demand of 86.5 kW. Selvær electric load information are summarized in Table 5.19.

Table 5.19: Selvær population and electric load data.

Parameter	**Value**
Population	55
Houses	14
Yearly energy consumption [kWh/y]	345 976
Peak demand [kW]	86.5

In Figure 5.17 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

5.4.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at

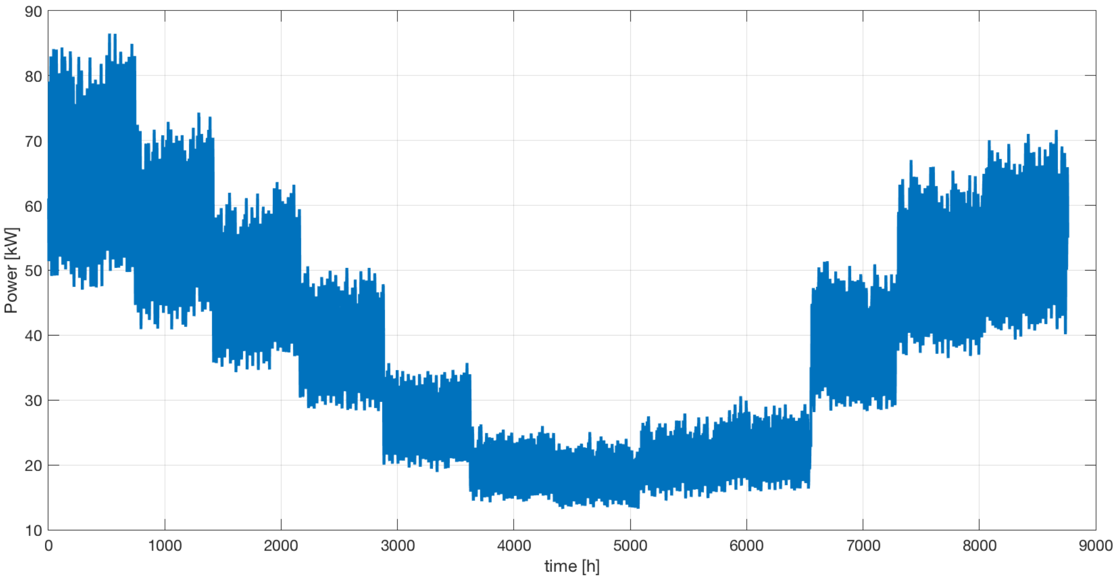


Figure 5.17: Selvær electric load.

10 m height) and solar radiation on PV surface are shown in Figure A.3a, A.3b and A.3c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.3, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.4.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.20.LCOE results in 0.31 €/kWh; a detailed breakdown cost can be observed in Figure A.12c.
As can be noted in Table 5.20, main cost contributions are related to wind turbine and hydrogen unit; PV capacity is low since the limited resource does not make economically feasible/profitable a larger installation.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.3.

Table 5.20: Hybrid P2P configuration.

Component	**Size**	**NPC**
PV	10 kW	17 047 €
Wind	244 kW	394 600 €
Fuel cell	85 kW	240 924 €
Electrolyzer	69 kW	413 595 €
Hydrogen	12 744 kWh	224 931 €
Battery	72 kWh	48 941 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.31 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.21. In case of only-battery

Table 5.21: Only-battery configuration.

Component	**Size**	**NPC**
PV	5 kW	8523 €
Wind	641 kW	1 037 445 €
Battery	5030 kWh	3 398 691 €

scenario, both wind and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply. This aspect clearly impacts on NPC, as can be noted in Table 5.21. LCOE turns out to be 1.02 €/kWh.

5.4.4 Alternative scenarios and LCOE comparison

In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 1.47 €/kWh.
In the diesel scenario, a 90 kW generator is assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.22. In this case, LCOE results in 0.97 €/kWh.

Table 5.22: Diesel scenario.

Parameter	**Value**
Rated power [kW]	90
Yearly fuel consumption [l/y]	155 985
Yearly CO_2 emissions [ton/y]	498

In Table 5.23 the LCOE of the different scenarios for Selvær island are collected.

Table 5.23: LCOE comparison.

Scenario	**LCOE [€/kWh]**
H2-battery	0.31
Only-hydrogen	0.31
Only-battery	1.02
Sea cable	1.47
Diesel	0.97

5.5 Lurøya island

Lurøya is an island in Lurøy municipality, Nordland county. Basing on the most recent data (2017), Støttvær has 138 permanent inhabitants; on the islands there is only a small shop serving local community. The island is located about 5.8 km far from the mainland and according to NVE information, it has a local grid without sea cable connection to national system.
Lurøya reaches extremely low temperatures during winter (i.e. minimum value in February is almost -17 °C) and during summer maximum does not exceed 20 °C; the annual average temperature is 3.48 °C. As regards wind potential, island exhibits a good resource during winter months (with peaks of 20 m/s) but it reduces in summer (as typical of northern locations); therefore, yearly average wind speed at 10 m height results around 5.82 m/s.
As it occurs for other islands, a remarkable seasonal variation affects solar potential: radiation is quite limited in autumn and winter months while it reaches its maximum during May and June.

Figure 5.18: Lurøya location (modified from [47]).

5.5.1 Electric load

On the basis of population data, residential electric load of Lurøya is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Lurøya's building stock consists of 35 houses. After cartographic evaluation, the shop floor area is assumed equal to 300 m^2. Therefore, the yearly energy consumption results in 861 179 kWh/y with a peak demand of 218 kW. Lurøya electric load information are summarized in Table 5.24.

Table 5.24: Lurøya population and electric load data.

Parameter	**Value**
Population	138
Houses	35
Yearly energy consumption [kWh/y]	861 179
Peak demand [kW]	218

In Figure 5.19 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

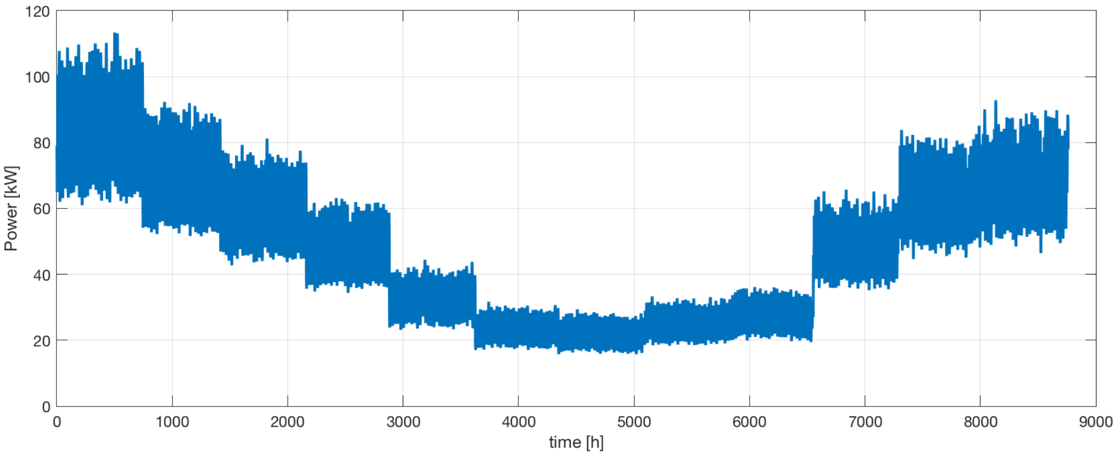


Figure 5.19: Lurøya electric load.

5.5.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.4a, A.4b and A.4c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.4, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.5.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.25. LCOE results in 0.53 €/kWh; a detailed breakdown cost can be observed in Figure A.12d.
As can be noted in Table 5.25, main cost contributions are related to wind turbine and hydrogen unit; PV capacity is low since the limited resource does not make economically feasible/profitable a larger installation.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.4.

Table 5.25: Hybrid P2P configuration.

Component	Size	NPC
PV	7 kW	11 933 €
Wind	1629 kW	2 636 404 €
Fuel cell	228 kW	500 657 €
Electrolyzer	613 kW	1 644 273 €
Hydrogen	49 995 kWh	882 400 €
Battery	21 kWh	17 650 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.53 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.26.

Table 5.26: Only-battery configuration.

Component	Size	NPC
PV	5 kW	8523 €
Wind	2450 kW	3 963 820 €
Battery	13 243 kWh	8 947 732 €

In case of only-battery scenario, both wind and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply. This aspect clearly impacts on NPC, as can be noted in Table 5.26. LCOE turns out to be 1.19 €/kWh.

5.5.4 Alternative scenarios and LCOE comparison

In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.23 €/kWh.
In the diesel scenario, two 110 kW generators are assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.27. In this case, LCOE results in 0.89 €/kWh.

Table 5.27: Diesel scenario.

Parameter	**Value**
Rated power [kW]	2x110
Yearly fuel consumption [l/y]	335 001
Yearly CO_2 emissions [ton/y]	1005

In Table 5.28 the LCOE of the different scenarios for Lurøya island are collected.

Table 5.28: LCOE comparison.

Scenario	**LCOE [€/kWh]**
H2-battery	0.53
Only-hydrogen	0.53
Only-battery	1.19
Sea cable	0.23
Diesel	0.89

5.6 Møkster island

Møkster is an island in Austevoll municipality, Vestland county. Basing on the most recent data (2017), Møkster has 53 permanent inhabitants; on the island there are a school and a shop serving the local community.
The island is part of Austevoll archipelago, whose islands are connected each other and to national system by several sea cables: in particular, a 1.16 km cable (5kV) connects Møkster to Little Kalsøya and it has been in operation since 1954.
Due to its location in the south-west of Norway, Møkster does not experience extreme weather conditions: in February minimum temperature is around 0 °C, while in summer more than 20°C can be reached; the annual average temperature results in 8.74 °C.
Møkster is characterized by very abundant wind resource: an annual average wind speed of 6.6 m/s (with peaks up to 20 m/s during winter) is recorded.
As it happens for other islands, solar potential strictly depends on seasons: radiation is quite low in autumn and winter months while it reaches its maximum during May and June.

Figure 5.20: Møkster location (modified from [47]).

5.6.1 Electric load

On the basis of population data, residential electric load of Møkster is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Møkster's building stock consists of 13 houses. After cartographic evaluation, the shop and school floor areas are assumed respectively equal to 130 m^2 and 345 m^2. Therefore, the yearly energy consumption results in 367 258 kWh/y with a peak demand of 88.6 kW. Møkster electric load information are summarized in Table 5.29.

Table 5.29: Møkster population and electric load data.

Parameter	Value
Population	53
Houses	13
Yearly energy consumption [kWh/y]	367 258
Peak demand [kW]	88.6

In Figure 5.21 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

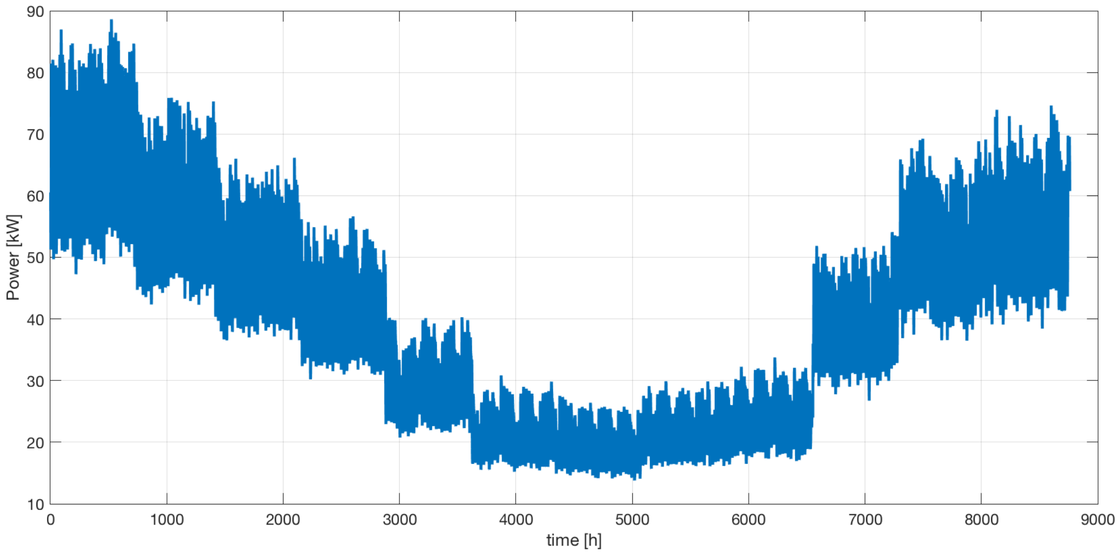


Figure 5.21: Møkster electric load.

5.6.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.5a, A.5b and A.5c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.5, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.6.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.30. LCOE results in 0.38 €/kWh; a detailed breakdown cost can be observed in Figure A.12e.
As can be noted in Table 5.30, main cost contributions are related to wind turbine and hydrogen unit.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.5.

Table 5.30: Hybrid P2P configuration.

Component	Size	NPC
PV	39 kW	66 589 €
Wind	307 kW	496 430 €
Fuel cell	90 kW	252 178 €
Electrolyzer	105 kW	537 889 €
Hydrogen	17 981 kWh	317 357 €
Battery	142 kWh	96 091 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.39 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.31.

Table 5.31: Only-battery configuration.

Component	Size	NPC
PV	410 kW	698 217 €
Wind	569 kW	920 656 €
Battery	3247 kWh	2 193 754 €

In case of only-battery scenario, both RES and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply; in particular, PV capacity increases by more than eight times. This aspect clearly impacts on NPC, as can be noted in Table 5.31. LCOE turns out to be 0.84 €/kWh.

5.6.4 Alternative scenarios and LCOE comparison

In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.14 €/kWh.
In the diesel scenario, a 90 kW generator is assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.32. In this case, LCOE results in 0.93 €/kWh.

Table 5.32: Diesel scenario.

Parameter	**Value**
Rated power [kW]	90
Yearly fuel consumption [l/y]	159 888
Yearly CO_2 emissions [ton/y]	480

In Table 5.33 the LCOE of the different scenarios for Møkster island are collected.

Table 5.33: LCOE comparison.

Scenario	**LCOE [€/kWh]**
H2-battery	0.38
Only-hydrogen	0.39
Only-battery	0.84
Sea cable	0.14
Diesel	0.93

5.7 Fjørtofta island

Fjørtofta is an island in Ålesund municipality, Møre og Romsdal county. Basing on the most recent data (2015), Fjørtofta has 136 permanent inhabitants; on the island there are a school and a shop serving the local community.
Fjørtofta is part of Nordøyane archipelago (together with Haramsøya, Flepsøya and Flemsøya) and several sea cables connect the islands to each other and to the mainland; in particular, a 2.9 km cable (22 kV) connects Fjørtofta with the nearby island of Flemsøya.
On the island, ambient temperature seldom goes below zero during winter and it reaches more than 20°C in summer: thus, Fjørtofta does not face up to harsh environmental conditions (i.e. annual average temperature is 7.9 °C).
As concerns wind potential, Fjørtofta has quite good resource: yearly average wind speed results in 5.6 m/s with maximum recorded speed over 20 m/s.
As usual, solar radiation is quite limited during cold months and it reaches its maximum in May and June.

Figure 5.22: Fjørtofta location (modified from [47]).

5.7.1 Electric load

On the basis of population data, residential electric load of Fjørtofta is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Fjørtofta's building stock consists of 34 houses. After cartographic evaluation, the shop and school floor areas are assumed respectively equal to 190 m^2 and 1150 m^2. Therefore, the yearly energy consumption results in 1 031 253 kWh/y with a peak demand of 246.7 kW. Fjørtofta electric load information are summarized in Table 5.34.

Table 5.34: Fjørtofta population and electric load data.

Parameter	Value
Population	136
Houses	34
Yearly energy consumption [kWh/y]	1 031 253
Peak demand [kW]	246.7

In Figure 5.23 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

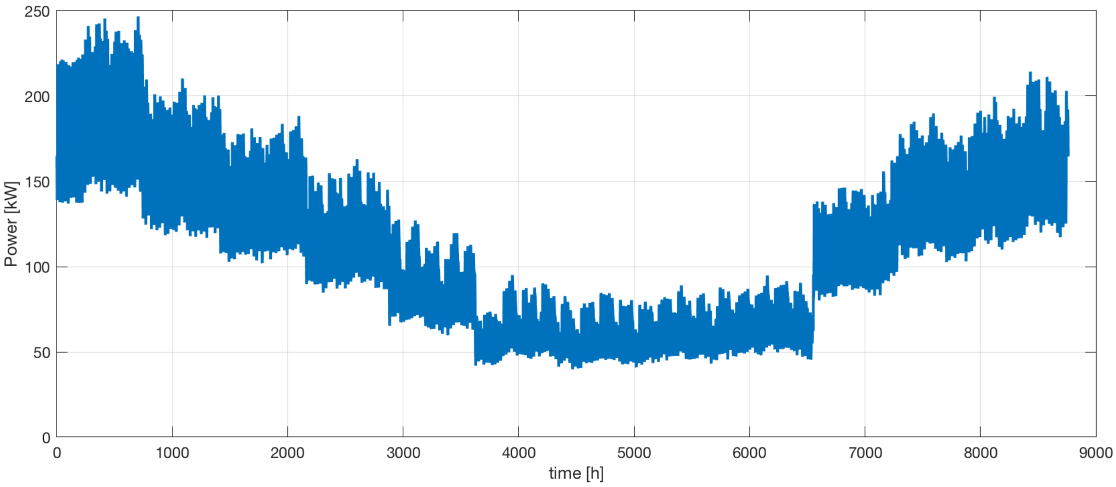


Figure 5.23: Fjørtofta electric load.

5.7.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.6a, A.6b and A.6c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.6, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.7.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.35. LCOE results in 0.78 €/kWh; a detailed breakdown cost can be observed in Figure A.12f.
As can be noted in Table 5.35, main cost contributions are related to wind turbine and hydrogen unit; PV capacity is quite limited since scarcity of solar resource does not make economically feasible/profitable a larger installation.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.6.

Table 5.35: Hybrid P2P configuration.

Component	Size	NPC
PV	5 kW	8525 €
Wind	4358 kW	705 0910 €
Fuel cell	246 kW	443 927 €
Electrolyzer	518 kW	1 259 425 €
Hydrogen	29 219 kWh	515 696 €
Battery	1284 kWh	867 230 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.86 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.36.

Table 5.36: Only-battery configuration.

Component	Size	NPC
PV	161 kW	275 076 €
Wind	4309 kW	6 971 271 €
Battery	9463 kWh	6 393 822 €

In case of only-battery scenario, both RES and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply; in particular, PV capacity increases by ten times. This aspect clearly impacts on NPC, as can be noted in Table 5.36. LCOE turns out to be 1.05 €/kWh.

5.7.4 Alternative scenarios and LCOE comparison

In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.14 €/kWh.
In the diesel scenario, two 125 kW generators are assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.37. In this case, LCOE results in 0.89 €/kWh.

Table 5.37: Diesel scenario.

Parameter	Value
Rated power [kW]	2x125
Yearly fuel consumption [l/y]	397 267
Yearly CO_2 emissions [ton/y]	1192

In Table 5.38 the LCOE of the different scenarios for Fjørtofta island are collected.

Table 5.38: LCOE comparison.

Scenario	LCOE [€/kWh]
H2-battery	0.78
Only-hydrogen	0.86
Only-battery	1.05
Sea cable	0.14
Diesel	0.89

5.8 Lepsøya island

Lepsøya is an island in Ålesund municipality, Møre og Romsdal county. Basing on the most recent data (2015), Lepsøya has 313 permanent inhabitants; on the island there are a school and a shop serving the local community.
The island lies 3.3 km far from the mainland and it is connected to the national grid by a 4.6 km sea cable (24 kV) that has been in operation since 2011.
Lepsøya does not face extreme environmental conditions: winter temperatures are around 0 °C (except in December when temperature reaches its minimum at almost -8 °C) while in summer maximum values just under 20 °C are recorded; yearly average temperature is 7.9 °C
Lepsøya exhibits very large wind potential: namely, annual average wind speed results in 6.86 m/s with maximum speed over 20 m/s occurring in winter. As usual, solar radiation has seasonal trend with lower values during autumn and winter and peaks during May and June.

5.8.1 Electric load

On the basis of population data, residential electric load of Lepsøya is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Lepsøya's building stock

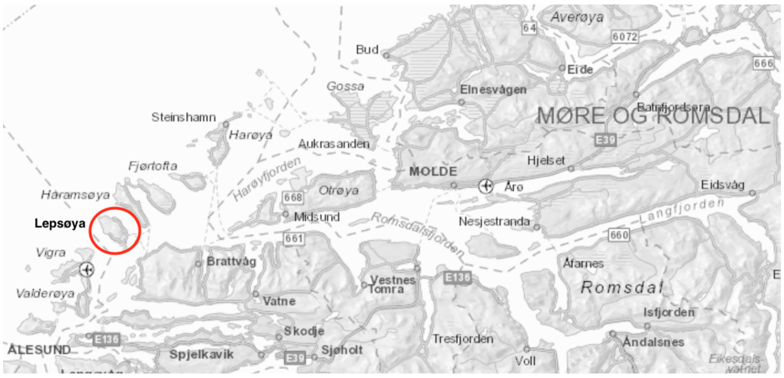


Figure 5.24: Lepsøya location (modified from [47]).

consists of 78 houses. After cartographic evaluation, the shop and school floor areas are assumed respectively equal to 460 m^2 and 1015 m^2. Therefore, the yearly energy consumption results in 2 030 630 kWh/y with a peak demand of 472.7 kW. Lepsøya electric load information are summarized in Table 5.39.

Table 5.39: Lepsøya population and electric load data.

Parameter	Value
Population	313
Houses	78
Yearly energy consumption [kWh/y]	2 030 630
Peak demand [kW]	472.7

In Figure 5.25 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

5.8.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.7a, A.7b and A.7c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.7, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

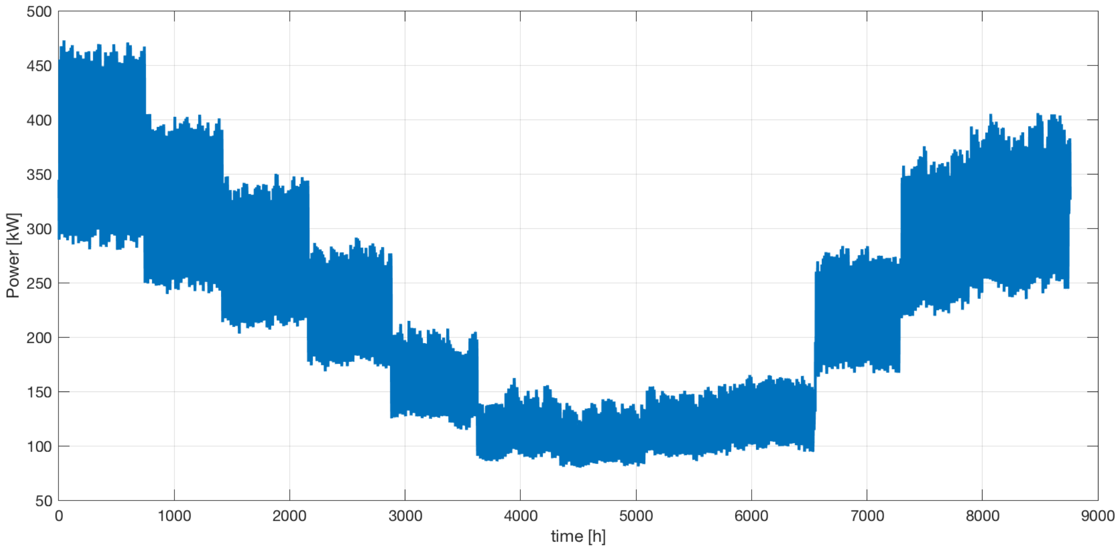


Figure 5.25: Lepsøya electric load.

5.8.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.40. LCOE results in 0.40 €/kWh; a detailed breakdown cost can be observed in Figure A.12g.
As can be noted in Table 5.40, main cost contributions are related to wind turbine and hydrogen unit; PV capacity is quite low since the limited resource does not make economically feasible/profitable a larger installation.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.7.

Table 5.40: Hybrid P2P configuration.

Component	Size	NPC
PV	10 kW	17 047 €
Wind	2177 kW	3 521 673 €
Fuel cell	490 kW	862 228 €
Electrolyzer	1331 kW	2 716 628 €
Hydrogen	149 326 kWh	2 635 553 €
Battery	66 kWh	55 846 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.40 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.41.

Table 5.41: Only-battery configuration.

Component	**Size**	**NPC**
PV	10 kW	17 047 €
Wind	5631 kW	9 110 869 €
Battery	24 745 kWh	16,719,050 €

In case of only-battery scenario, both RES and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply. This aspect clearly impacts on NPC, as can be noted in Table 5.41. LCOE turns out to be 1.01 €/kWh.

5.8.4 Alternative scenarios and LCOE comparison

In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.14 €/kWh.
In the diesel scenario, two 240 kW generators are assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.42. In this case, LCOE results in 0.88 €/kWh.

Table 5.42: Diesel scenario.

Parameter	**Value**
Rated power [kW]	2x240
Yearly fuel consumption [l/y]	778 834
Yearly CO_2 emissions [ton/y]	2337

In Table 5.43 the LCOE of the different scenarios for Lepsøya island are collected.

Table 5.43: LCOE comparison.

Scenario	LCOE [€/kWh]
H2-battery	0.40
Only-hydrogen	0.40
Only-battery	1.01
Sea cable	0.14
Diesel	0.88

5.9 Røst island

Røst is an island in the homonymous municipality in Nordland county. Basing on the most recent data (2020), Røst has 498 permanent inhabitants. The island is part of Lofoten archipelago and it is located very far from the mainland: it lies more than 90 km off from Bødo coast and more than 45 km from Moskenesøya island. A 33.2 km cable (24 kV) in operation since 2009 connects Røst with Værøy island which is in turn connected to the mainland by another sea cable.
Although its high-latitude location, Røst does not experience extremely harsh weather conditions: ambient temperature ranges between -5 °C in January and almost 15 °C in July, with an annual average value of 6.98 °C.

Figure 5.26: Røst location (modified from [47]).

As regards wind potential, island exhibits a remarkable resource: annual average wind speed reaches 7.83 m/s with peaks over 22.5 m/s occurring during winter. High latitude dramatically affects solar potential: namely, radiation is significant only during May, June and July.

5.9.1 Electric load

On the basis of population data, residential electric load of Røst is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Røst's building stock consists of 125 houses. After cartographic evaluation, the shop and school floor areas are assumed respectively equal to 700 m^2 and 1500 m^2. Therefore, yearly energy consumption results in 3 213 030 kWh/y with a peak demand of 758.6 kW. Røst electric load information are summarized in Table 5.44.

Table 5.44: Røst population and electric load data.

Parameter	Value
Population	498
Houses	125
Yearly energy consumption [kWh/y]	3 213 030
Peak demand [kW]	758.6

In Figure 5.27 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

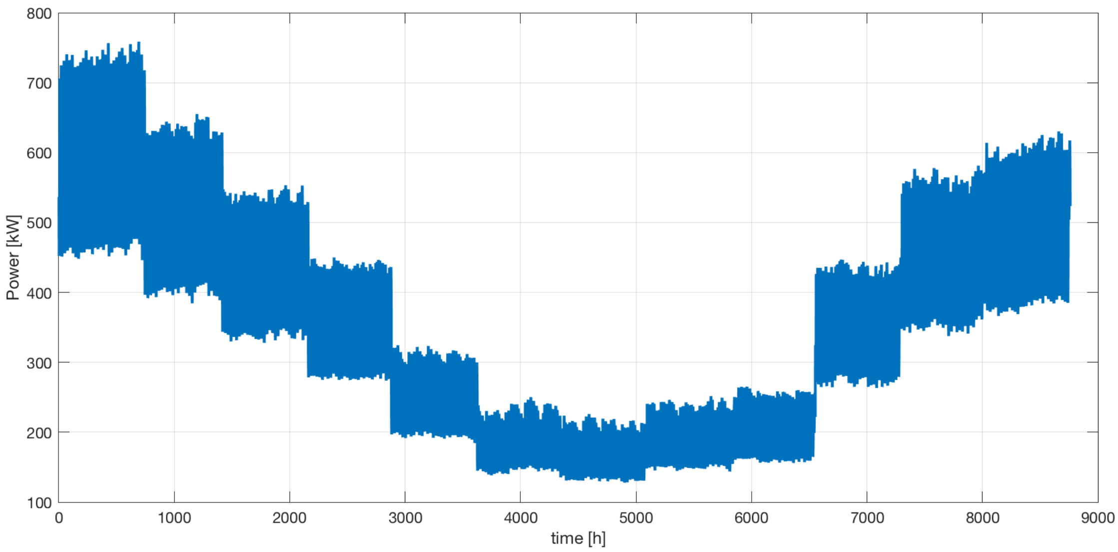


Figure 5.27: Røst electric load.

5.9.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.8a, A.8b and A.8c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.8, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.9.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.45. LCOE results in 0.22 €/kWh; a detailed breakdown cost can be observed in Figure A.12h.
As can be noted in Table 5.45, main cost contributions are related to wind turbine and hydrogen unit.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.8.

Table 5.45: Hybrid P2P configuration.

Component	**Size**	**NPC**
PV	10 kW	17 047 €
Wind	1888 kW	3 054 614 €
Fuel cell	775 kW	1 159 785 €
Electrolyzer	791 kW	2 007 569 €
Hydrogen	94 499 kWh	1 667 871 €
Battery	280 kWh	189 225 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.22 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.46.

Table 5.46: Only-battery configuration.

Component	Size	NPC
PV	103 kW	174 767 €
Wind	9237 kW	14 944 579 €
Battery	10 210 kWh	6 898 351 €

In case of only-battery scenario, both RES and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply. This aspect clearly impacts on NPC, as can be noted in Table 5.46. LCOE turns out to be 0.55 €/kWh.

5.9.4 Alternative scenarios and LCOE comparison

In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.25 €/kWh.
In the diesel scenario, two 380 kW generators are assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.47. In this case, LCOE results in 0.88 €/kWh.

Table 5.47: Diesel scenario.

Parameter	Value
Rated power [kW]	2x380
Yearly fuel consumption [l/y]	1 231 047
Yearly CO_2 emissions [ton/y]	3693

In Table 5.48 the LCOE of the different scenarios for Røst island are collected.

Table 5.48: LCOE comparison.

Scenario	LCOE [€/kWh]
H2-battery	0.22
Only-hydrogen	0.22
Only-battery	0.55
Sea cable	0.25
Diesel	0.88

5.10 Røvær island

Røvær is an island in Haugesund municipality, Rogaland county. Basing on the most recent data (2019), Røvær has 86 permanent inhabitants; on the island there are a kindergarten, a school and a shop serving the local community.
The island is located about 10 km far from the Haugesund coast and it is connected to the national grid by a 7.8 km sea-cable (24kV) that is in operation since 2005.
Due to its location in the south-west of Norway, Røvær temperature ranges between 0 °C in January and almost 19 °C in July; the yearly average temperature results in 8.9 °C.
Røvær is characterized by a quite abundant wind resource: the annual average wind speed results in 6.6 m/s but peaks over 20 m/s occur during winter.
As regards solar potential, due to its lower latitude, Røvær exhibits higher irradiance with respect to other islands under investigation.

Figure 5.28: Røvær location (modified from [47]).

5.10.1 Electric load

On the basis of population data, residential electric load of Røvær is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Røvær's building stock consists of 22 houses. After cartographic evaluation, the shop, school and kindergarten floor areas are assumed respectively equal to 120 m^2, 355 m^2 and 200 m^2. Therefore, yearly energy consumption results in 605 290 kWh/y with a peak demand of 143.4 kW. Røvær electric load information are summarized in Table 5.49.

Table 5.49: Røvær population and electric load data.

Parameter	Value
Population	86
Houses	22
Yearly energy consumption [kWh/y]	605 290
Peak demand [kW]	143.4

In Figure 5.29 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

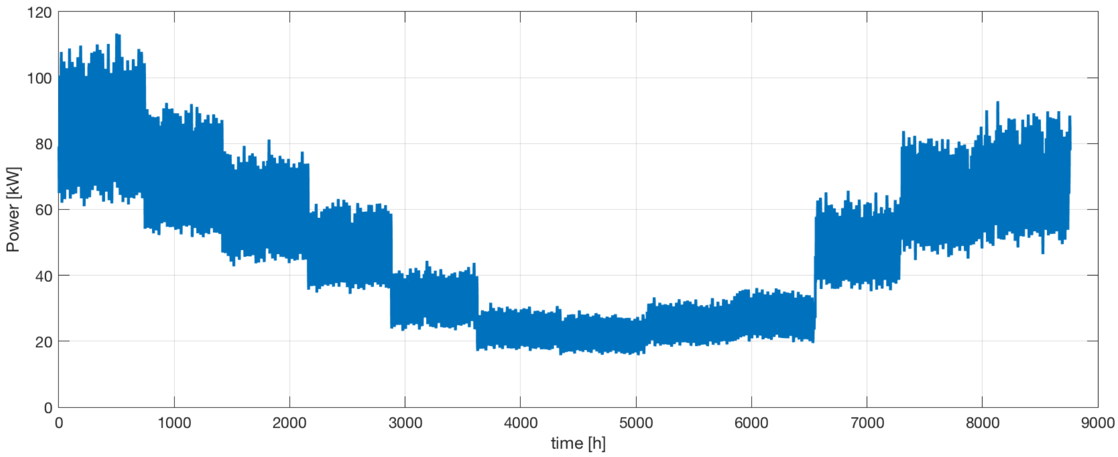


Figure 5.29: Røvær electric load.

5.10.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.9a, A.9b and A.9c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.9, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.10.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.50. LCOE results in 0.36 €/kWh; a detailed breakdown cost can be observed in Figure A.12i.
As can be noted in Table 5.50, main cost contributions are related to wind turbine and hydrogen unit; PV capacity is quite low since the limited resource does not make economically feasible/profitable a larger installation.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.9.

Table 5.50: Hybrid P2P configuration.

Component	Size	NPC
PV	30 kW	51 325 €
Wind	517 kW	836 158 €
Fuel cell	143 kW	356 045 €
Electrolyzer	181 kW	769 311 €
Hydrogen	35 179 kWh	620 895 €
Battery	160 kWh	108 175 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.37 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.51.

Table 5.51: Only-battery configuration.

Component	Size	NPC
PV	563 kW	959 180 €
Wind	1000 kW	1 618 194 €
Battery	9683 kWh	6 542 422 €

In case of only-battery scenario, both RES and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply. This aspect clearly impacts on NPC, as can be noted in Table 5.51. LCOE turns out to be 1.21 €/kWh.

5.10.4 Alternative scenarios and LCOE comparison

In the case of sea-cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.28 €/kWh.
In the diesel scenario, two 75 kW generators are assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.52. In this case, LCOE results in 0.90 €/kWh.

Table 5.52: Diesel scenario.

Parameter	**Value**
Rated power [kW]	2x75
Yearly fuel consumption [l/y]	233873
Yearly CO_2 emissions [ton/y]	702

In Table 5.53 the LCOE of the different scenarios for Røvær island are collected.

Table 5.53: LCOE comparison.

Scenario	**LCOE [€/kWh]**
H2-battery	0.36
Only-hydrogen	0.37
Only-battery	1.21
Sea-cable	0.28
Diesel	0.90

5.11 Skrova island

Skrova is an island in Vagan municipality, Nordland county. Basing on the most recent data (2019), Skrova has 196 permanent inhabitants; on the island there are a kindergarten, a school and a shop serving the local community. Skrova is part of the Lofoten archipelago and it lies 9 km south-east of the town of Svolvær; a 9 km seacable in operation since 1979 connects the island to the national electric system. Skrova has to cope with harsh environmental conditions: during winter ambient

temperature is usually below zero (with a minimum value of -9 °C in December) and in summer it reaches only 17 °C; the annual temperature average results in 5.76 °C.
As regards wind potential, Skrova exhibits good resource: 6.7 m/s yearly average with several peaks over 15 m/s is recorded. Due to high-latitude location, solar potential has strong seasonal variability: solar resource is almost absent during winter while it reaches its maximum in May and June, as usual.

Figure 5.30: Skrova location (modified from [47]).

5.11.1 Electric load

On the basis of population data, residential electric load of Skrova is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Skrova's building stock consists of 49 houses. After cartographic evaluation the shop, school and kindergarten floor areas are assumed respectively equal to 155 m^2, 690 m^2 and 150 m^2.
Therefore, yearly energy consumption results in 1 294 400 kWh/y with a peak demand of 304.8 kW.

Skrova electric load information are summarized in Table 5.54.

Table 5.54: Skrova population and electric load data.

Parameter	Value
Population	196
Houses	49
Yearly energy consumption [kWh/y]	1 294 400
Peak demand [kW]	304.8

In Figure 5.31 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

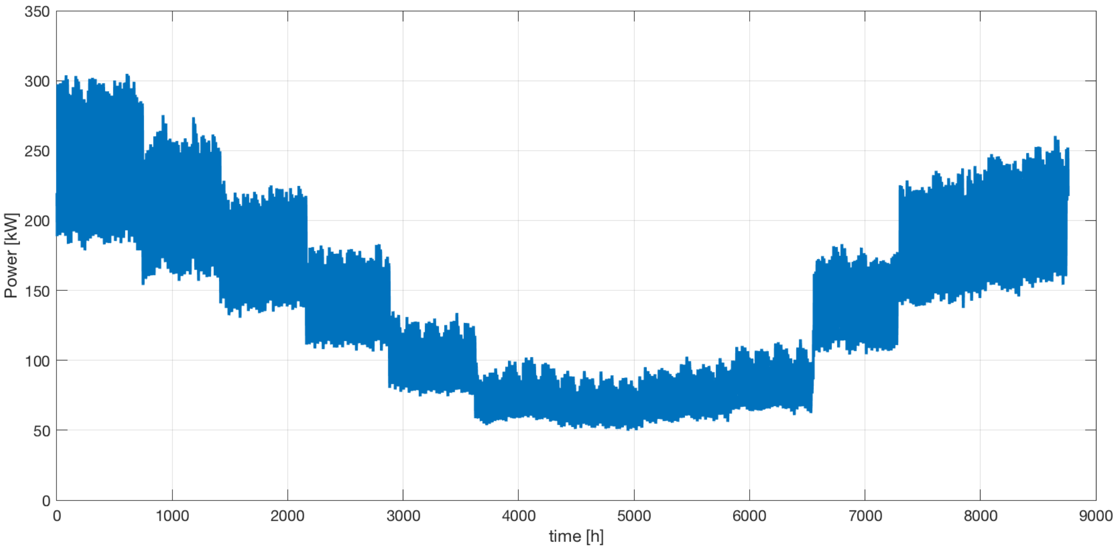


Figure 5.31: Skrova electric load.

5.11.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.10a, A.10b and A.10c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.10, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.11.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are summarized in Table 5.55. LCOE results in 0.26 €/kWh; a detailed breakdown cost can be observed in Figure A.12j.
As can be noted in Table 5.55, main cost contributions are related to wind turbine and hydrogen unit.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.10.

Table 5.55: Hybrid P2P configuration.

Component	Size	NPC
PV	82 kW	140 027 €
Wind	1095 kW	1 771 333 €
Fuel cell	301 kW	605 148 €
Electrolyzer	226 kW	1 002 229 €
Hydrogen	37 760 kWh	666 446 €
Battery	18 kWh	15 481 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.26 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.56.

Table 5.56: Only-battery configuration.

Component	Size	NPC
PV	712 kW	1 213 850 €
Wind	1339 kW	2 166 366 €
Battery	9469 kW	6 397 565 €

In case of only-battery scenario, both RES and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply. This aspect clearly impacts on NPC, as can be noted in Table 5.56. LCOE turns out to be 0.61 €/kWh.

5.11.4 Alternative scenarios and LCOE comparison

In the case of sea-cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.20 €/kWh.
In the diesel scenario, two 155 kW generators are assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.57. In this case, LCOE results in 0.88 €/kWh.

Table 5.57: Diesel scenario.

Parameter	**Value**
Rated power [kW]	2x155
Yearly fuel consumption [l/y]	497 514
Yearly CO_2 emissions [ton/y]	1493

In Table 5.58 the LCOE of the different scenarios for Skrova island are collected.

Table 5.58: LCOE comparison.

Scenario	**LCOE [€/kWh]**
H2-battery	0.26
Only-hydrogen	0.26
Only-battery	0.61
Sea-cable	0.20
Diesel	0.88

5.12 Værøya island

Værøya is an island in Væroy municipality, Nordland county. Basing on the most recent data (2018), Værøya has 640 permanent inhabitants; on the island there are a kindergarten, a school and a shop serving the local community. Værøya is part of the Lofoten archipelago and it lies 15.6 km south of Moskenesøya; a 27.9 km sea cable in operation since 1986 connects the island to the national electric system.
Although its high-latitude location, Værøya does not experience extremely harsh weather conditions: ambient temperature ranges between -5.5 °C in December and

almost 25 °C in August, with an annual average value of 6.84 °C.
Værøya exhibits very abundant wind potential: yearly average wind speed results in 7.4 m/s with several peaks over 18 m/s that occur during winter.
As concerns solar potential, high latitude determines strong seasonal variations: solar resource is quite limited in autumn and winter months while it reaches its maximum during May and June.

Figure 5.32: Værøya location (modified from [47]).

5.12.1 Electric load

On the basis of population data, residential electric load of Værøya is estimated by applying the model described in Section 4.1. According to *reference building* specification, 4 residents per house are assumed; thus, Værøya's building stock consists of 160 houses. After cartographic evaluation, the shop, school and kindergarten floor areas are assumed respectively equal to 580m^2, 2500 m^2 and 600 m^2.
Therefore, yearly energy consumption results in 4 279 804 kWh/y with a peak demand of 985.2 kW. Værøya electric load information are summarized in Table 5.59. In Figure 5.33 yearly electric load profile is depicted: as expected, it shows a clear seasonal variability with higher energy demand occurring during winter.

Table 5.59: Værøya population and electric load data.

Parameter	Value
Population	640
Houses	160
Yearly energy consumption [kWh/y]	4 279 804
Peak demand [kW]	985.2

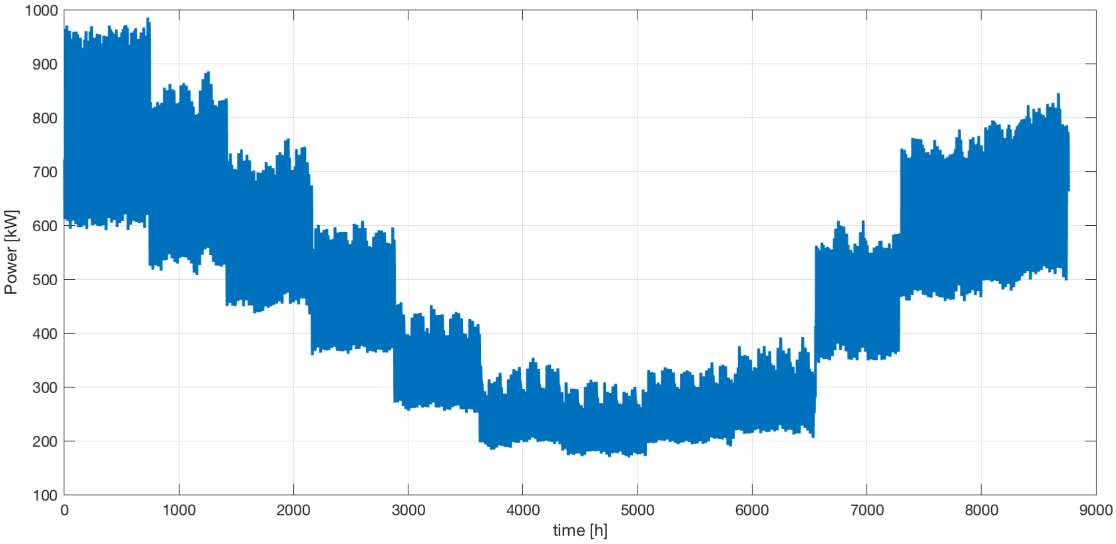


Figure 5.33: Værøya electric load.

5.12.2 Meteorological data and RES production

According to the procedure presented in Section 4.3, meteorological data for the TMY are extracted from PVGIS. Optimal values of PV panel inclination and orientation are summarized in Table A.2. Ambient temperature, wind speed (at 10 m height) and solar radiation on PV surface are shown in Figure A.11a, A.11b and A.11c. Single PV panel (365 W) and wind turbine (80 kW) power productions, shown in Figure A.11, are normalized with respect to installed capacity and provided as input data to techno-economic optimization tool.

5.12.3 Sizing procedure and economic analysis

Hydrogen-battery

In case of hybrid system, both short-term (i.e. battery) and long-term (i.e. hydrogen) energy storage solutions are adopted. The outcomes of sizing procedure are

summarized in Table 5.60. LCOE results in 0.24 €/kWh; a detailed breakdown cost can be observed in Figure A.12k.
As can be noted in Table 5.60, main cost contributions are related to wind turbine and hydrogen unit.
Energy balances (RES-load and surplus-deficit) and segmentation of load supply and RES usage can be analysed in Figure A.11.

Table 5.60: Hybrid P2P configuration.

Component	Size	NPC
PV	235 kW	399 834 €
Wind	2991 kW	4 839 930 €
Fuel cell	944 kW	1 344 539 €
Electrolyzer	894 kW	2 435 217 €
Hydrogen	16 9126 kWh	2 985 014 €
Battery	20 kWh	16 768 €

Only-hydrogen

The outcomes of sizing procedure are reported in Table A.1. In this scenario the LCOE turns out to be 0.24 €/kWh.

Only-battery

The results of sizing procedure are summarized in Table 5.61.

Table 5.61: Only-battery configuration.

Component	Size	NPC
PV	255 kW	434 900 €
Wind	9685 kW	15 670 468 €
Battery	21029 kWh	14 208 468 €

In case of only-battery scenario, both RES and storage unit sizes result significantly larger: namely, the plant has to be oversized in order to ensure load supply. This aspect clearly impacts on NPC, as can be noted in Table 5.61. LCOE turns out to be 0.56 €/kWh.

5.12.4 Alternative scenarios and LCOE comparison

In the case of sea cable scenario, detailed cost item description is omitted due to confidentiality reasons but the resulting LCOE is 0.20 €/kWh.
In the diesel scenario, tro 495 kW generators are assumed to be installed; according to the procedure described in Section 4.5, yearly fuel consumption and CO_2 emissions are evaluated. The outcomes are summarized in Table 5.62. In this case, LCOE results in 0.87 €/kWh.

Table 5.62: Diesel scenario.

Parameter	Value
Rated power [kW]	2x495
Yearly fuel consumption [l/y]	1 632 417
Yearly CO_2 emissions [ton/y]	4898

In Table 5.63 the LCOE of the different scenarios for Værøya island are collected.

Table 5.63: LCOE comparison.

Scenario	LCOE [€/kWh]
H2-battery	0.24
Only-hydrogen	0.24
Only-battery	0.56
Sea cable	0.20
Diesel	0.87

Chapter 6

Discussion of the results

6.1 LCOE and techno-economic considerations

After developing a detailed feasibility analysis for the 12 selected islands, a comprehensive LCOE overview can be provided and a series of techno-economic considerations can be pointed out. In Table 6.1 the LCOE of the investigated scenarios are collected.

Table 6.1: LCOE comparison.

Island	**LCOE [€/kWh]**				
	H2-battery	**Only-H2**	**Only-battery**	**Sea cable**	**Diesel**
Støttvær	0.63	0.66	1.18	0.35	1.04
Linesøya	0.59	0.63	0.91	0.23	0.92
Fjøløy	0.82	0.85	1.29	0.17	0.90
Selvær	0.31	0.31	1.02	1.47	0.97
Lurøya	0.53	0.53	1.19	0.23	0.89
Møkster	0.38	0.39	0.84	0.14	0.93
Fjørtofta	0.78	0.86	1.05	0.14	0.89
Lepsøya	0.40	0.40	1.01	0.14	0.88
Røst	0.22	0.22	0.55	0.25	0.88
Rovær	0.36	0.37	1.21	0.28	0.90
Skrova	0.26	0.26	0.61	0.20	0.88
Værøya	0.24	0.24	0.56	0.20	0.87

As is evident, the LCOE of *H2-battery* solution always results lower than that of *only-battery* and *diesel* scenarios. In the case of RES-based system with hybrid

energy storage, LCOE ranges mainly between 0.2 and 0.6 €/kWh: the variations are mostly due to RES availability and electric load in the specific location; analysing the breakdown cost, it can be highlighted that, in general, the largest contributions comes from wind and hydrogen units while PV and battery have lower impact as long as their sizes are limited.
Focusing on the *only-battery* scenario, it is necessary to note that the feasibility of this solution is undermined by the need of oversizing the plant (both RES and storage unit) with a dramatical effect on NPC and thus LCOE.
In *only-hydrogen* scenario, due to the absence of alternative storage solutions, electrolyzer rated power and hydrogen storage size increase in order to produce and store a sufficient amount of hydrogen to cover the electric load in case of shortage. In this scenario the LCOE lies between H2-battery and only-battery values; the distance between only-hydrogen and H2-battery cost is clearly affected by the battery capacity installed in the hybrid configuration: namely, the variation is evident in Linesøya and Fjøløy (in which large capacity is installed) while it is quite limited in Røst and Værøya (in which small capacity is installed).
As concerns renewable energy production, in all the three scenarios above, the majority of power generation is due to wind turbines: namely, wind potential is abundant while solar resource is quite limited in both radiation intensity and length of the day (especially during winter).
In *sea cable* scenario, the LCOE strictly depends on two parameters: the length of the cable (that impacts on CAPEX) and the electric load (that affects OPEX and it is included in LCOE formula). Therefore, the comparison with other scenarios is not unique, but it changes depending on the island under investigation: namely, when comparing H2-battery and sea cable scenarios, RES-based system with hybrid storage results more convenient than sea cable in the case of Selvær and Røst islands, while it is a competitive solution in Røvær, Skrova and Værøya islands and it is more expensive in the other cases.
As regards *diesel* scenario, the LCOE turns out considerably high: the electricity cost is affected by frequent substitution of diesel generator (i.e. the lifetime is assumed equal to 16000 h, namely 2 years in continuous operation) and fuel cost (in which even transport and delivery have to be included). In addition, diesel scenario has clear environmental drawbacks, as discussed in Section 6.2.

6.2 Environmental analysis

On the basis of the results obtained for the 12 selected islands, a national scale analysis of environmental benefits related to the installation of Power-to-Power systems can be carried out. In this regard, it is pivotal to highlight that according to NVE 98% of electricity in Norway is produced by hydropower plants neither

with fossil fuel consumption nor carbon dioxide emissions during their operation; for these reasons, the analysis focuses only on diesel generators impact and it does not include sea cable scenario (since electricity is produced on the mainland). [66] Obviously, due to the large number of islands contained into the database, an extrapolation procedure is required to be adopted. Since the islands are already sorted according to community services provided on site, the extrapolation parameter is represented by the population and hence the number of houses.
Therefore, for each category, the diesel consumption and the CO_2 emissions of reference island are linearly scaled for all the insular locations in the subset. Finally, total avoided fuel consumption and emissions are determined. The outcomes of environmental analysis are collected in Table 6.2.

Table 6.2: Diesel consumption and CO_2 emission.

Reference island	Similar islands	Total diesel consumption [l/y]	Total CO_2 emissions [ton/y]
Støttvær	40	2 412 350	7237
Linesøya	14	2 497 957	7494
Fjøløy	3	1 337 757	4013
Selvær	12	1 927 534	5783
Lurøya	8	4 134 874	12 405
Møkster	6	1 328 303	3985
Fjørtofta	8	4 077 826	12 233
Lepsøya	11	8 816 803	26 450
Røst	7	12 468 044	37 404
Røvær	1	361 439	1084
Skrova	8	4 416 703	13 250
Værøya	8	16 987 343	50 962

Analysing the results in Table 6.2, it is self-evident that diesel generator installation does not represent a viable solution: besides the high costs previously assessed, fossil-based energy production is clearly environmentally unsustainable.

6.3 Sensitivity analysis

As discussed in Section 4.4, the techno-economic optimization tool determines the optimal system configuration that minimizes the LCOE while satisfying the constrain related to LPSP. The results achieved and commented in previous sections are obtained setting the LPSP target value equal to 0 (i.e. the system is sized to continuously met the load). In order to investigate the variation of LCOE basing on different LPSP target value, a sensitivity analysis is carried out: the optimization procedure is performed assuming a LPSP target value equal to 0.5%. The sizes of the components for the different scenarios are shown in Appendix A in Table A.3, A.4 and A.5. The LCOE expressed in €/kWh are compared in Table 6.3.

Table 6.3: Sensitivity analysis and LCOE comparison.

Island	**LPSP=0**			**LPSP=0.5**		
	H2-bat	**Only-H2**	**Only-bat**	**H2-bat**	**Only-H2**	**Only-bat**
Støttvær	0.63	0.66	1.18	0.60	0.62	0.86
Linesøya	0.59	0.63	0.91	0.55	0.63	0.81
Fjøløy	0.82	0.85	1.29	0.65	0.69	1.06
Selvær	0.31	0.31	1.02	0.28	0.29	0.65
Lurøya	0.53	0.53	1.19	0.50	0.50	0.91
Møkster	0.38	0.39	0.84	0.36	0.37	0.67
Fjørtofta	0.78	0.86	1.05	0.67	0.74	0.88
Lepsøya	0.40	0.40	1.01	0.37	0.38	0.86
Røst	0.22	0.22	0.55	0.19	0.20	0.40
Rovær	0.36	0.37	1.21	0.34	0.34	1.03
Skrova	0.26	0.26	0.61	0.24	0.24	0.42
Værøya	0.24	0.24	0.56	0.22	0.22	0.46

As expected, the LCOE resulting from the optimization process with LPSP set to 0.5 are lower than those previously obtained: LPSP target value equal to zero represents a stricter requirement to be fulfilled. More in detail, LPSP target value impacts on rated power of components and consequently on NPC and LCOE.
In *H2-battery* scenario, in the case of complete autonomy, the fuel cell is required to cover even peak load demand while in the other case fuel cell size may be lower. LCOE variation is even more marked in *only-battery* scenario, in which the requirement of continuous supply implies the installation of large and expensive battery storage system.
The sensitivity analysis points out that a small decrease in system autonomy can determine a significant cost reduction, although the load fraction that is not cover by the RES-storage system has to be met by external source; therefore, a trade-off between economic feasibility and environmental sustainability has to be reached.

Chapter 7

Conclusions

In future energy scenarios, deeper exploitation of renewable energy sources and electrification of final consumption are the key points of the strategy to be adopted to address climate change and reach carbon neutrality goal. In this framework, hydrogen plays a crucial role: namely, it represents the missing link in the energy transition since it allows to store large amount of renewable energy surplus that can be converted again into electricity or can be used in the hard-to-abate sectors (i.e. transport and industry). RES-based systems coupled with hydrogen storage represent a viable and promising solution in remote areas and islands, in which energy supply currently relies on diesel generators or expensive electric grid infrastructures.

This thesis work, that is developed as part of REMOTE EU-project, aims to evaluate the potential of Power-to-Power systems in remote islands in Norway. Due to its peculiar geographic conformation, Norway has more than 50 000 islands (including islet and skerry) which differ in size, number of inhabitants and distance from mainland. Therefore, in order to perform a national scale analysis, a database containing detailed information on Norwegian islands is developed; in particular, data related to population, geographical location, community services provided on site and current type of electrification are collected. A multiple-step data sorting procedure is implemented: firstly, starting from 492 islands, 153 are removed due to the absence of reliable population data, then 68 islands with direct connection to transmission and distribution system are excluded from the analysis; finally, unpopulated and near the coast islands are eliminated. Thus, after the preliminary data sorting, the database contains 138 islands that are grouped into 12 homogeneous categories on the basis of population size and community services; finally, for each category a single representative island is selected and analysed in detail. In order to properly evaluate the electric load of the selected islands, a methodology that takes into account the characteristics of Norwegian buildings and the peculiarity of the location under investigation is developed. More in detail, a model based

on specific literature data is implemented to estimate the residential electric load; the model provides validated results and it allows to generate realistic profile since random variation in shape and size are introduced. As concerns non-residential buildings, an Excel tool directly provided by a Norwegian research group is adopted: it allows to obtain both thermal and electric load profiles and according to several studies available in literature electricity is assumed as the only energy carrier; this assumption has to be verified on site but after post-processing electric load data it is evident that non-residential contribution is usually lower than 20% of the total community load and only half of it is related to thermal demand.
After assessing electric load, renewable energy production is evaluated by means of MATLAB code that runs on meteorological data extracted from PVGIS and provides hourly values of power produced by PV and wind. Since low temperatures improve solar cell performances and determine an air density increase, the model is developed taking into consideration the effect of ambient temperature on both solar and wind power generation.
The sizing procedure is carried out by using a techno-economic optimization tool implemented in the framework of REMOTE project; the code requires as input data load and RES hourly values and provides as output the system configuration that minimizes the LCOE while satisfying the required system autonomy (i.e. LPSP target value). At this stage, the sizing is performed imposing the complete autonomy condition (i.e. LPSP target set to 0). The LCOE of H2-battery solution is compared with that of four alternative scenarios: only-hydrogen, only-battery, sea cable and diesel. In the case of *sea cable* scenario, the LCOE is evaluated on the basis of the data provided by REMOTE project partner by including the specific characteristics of each island. As concerns *diesel* scenario, LCOE is assessed after developing a model to estimate hourly fuel consumption (on the basis of nominal size, partial load condition and modulation range) and related CO_2 emissions.
Focusing on the sizes of the components in *H2-battery* scenario, it is possible to highlight that in six islands out of twelve PV rated power is lower or equal to 10 kW, in four it is between 10 and 100 kW and only in two it is larger than 100 kW; on the contrary, wind rated power is always larger than 300 kW and it provides the main contribution to renewable energy production. This outcome points out that wind resource is the most abundant and exploitable, while solar potential is quite limited (due to both the low radiation intensity and the short length of the day during winter). In addition, the difference in rated power sizes clearly reflects on LCOE cost contribution: namely, analysing the breakdown cost it is possible to highlight that in ten islands out of twelve the PV share is considerably lower than wind one. As regards *only-battery* scenario, it is evident that in order to ensure load supply both RES and storage units have to be oversized with a dramatic impact on NPC and thus LCOE (especially due to battery cost increase). In *only-hydrogen* scenario, electrolyzer rated power and hydrogen storage size increase in order to

produce and store a sufficient amount of hydrogen to cover the electric load in case of shortage. As concerns *sea cable* scenario, the main parameters affecting LCOE value are the length of the cable and the electric load of the island: the combination of these factors can determine the cost-effectiveness of the solution (i.e. short length and high electric load, as occurs in Selvær) or its economic unsustainability (i.e. long distance and limited electric load, as it happens in Fjørtofta); however, it is necessary to emphasise that length and electric load can even counterbalance their own effects, as in the case of Røst and Væroya in which high distance and significant energy consumption result in quite low LCOE. In *diesel* scenario, LCOE is mainly impacted by frequent replacement (i.e. generator lifetime is assumed equal to 16000 hours that correspond to two years in continuous operation) and high fuel cost (in which even additional fee for transportation and delivery is included). Therefore, basing on previous considerations, the LCOE comparison is self-evident: the LCOE of H2-battery scenario always results lower than that obtained in only-hydrogen, only-battery and diesel case, while the comparison with sea cable scenario leads to conflicting outcomes that have to be further investigated. Although in most of the cases RES-based system with hybrid H2-battery storage results in a very cost-effective solution (LCOE in the range of 0.2-0.6 €/kWh), its LCOE is definitely lower than sea cable one only for Røst and Selvær, while it turns out to be very cost-competitive with the laying of new sea cable for Røvær, Skrova, Værøya, Møkster and Lepsøya and it is more expensive for Støttvær, Linesøya, Fjøløy, Lurøya and Fjørtofta. Furthermore, in order to deeply understand these findings, it is pivotal to highlight that in Norway 98% of electricity is produced by hydropower plants and then the electricity price is quite low: namely, this aspect boosts significantly the profitability of this solution. Thus, the techno-economic analysis confirms the expectations: H2-based Power-to-Power system represents a viable and promising solution to be installed in Norwegian islands.
After assessing the techno-economic feasibility, the environmental benefits arising from the installation of Power-to-Power system on a national scale are evaluated: the avoided fossil-fuel consumption and the related carbon dioxide emissions are estimated for the 138 islands included in the database. More in detail, for each category, diesel consumption and CO_2 emissions of reference island are linearly scaled (according to the number of houses) for all the insular locations in the subset. Environmental analysis reveals that the installation of Power-to-Power system can imply the saving of 60 766 934 diesel litre per year and 182 301 CO_2 ton/year.
Finally, a sensitivity analysis is carried out and the effect of lower autonomy requirement is assessed: the sizing procedure is performed again with a LPSP target value set to 0.5%. As expected, the LCOE result lower since LPSP target value impacts on system configuration and rated power of components. LCOE reduction is stronger in only-battery scenario, in which the requirement of continuous supply

implies the installation of large and expensive battery storage system. The sensitivity analysis points out that a small decrease in system autonomy can determine a significant cost reduction, although the load fraction that is not cover by the RES-storage system has to be met by external source. Thus, a trade-off between economic feasibility and environmental sustainability has to be reached.

Therefore, the techno-economic assessment and environmental analysis point out that the potential of Power-to-Power system in remote islands in Norway is enormous: RES-based systems with H2-battery storage allow to produce clean, reliable and cost-effective electricity exploiting local renewable sources and reducing (or even completely avoiding) fossil fuel consumption in 138 islands. The potential can be even larger than that assessed in this study since many islands are not included in the analysis due to the absence of reliable population data; therefore, the database can be further developed by collecting the missing data: direct population survey, community services census and real electric load measurement can significantly improve the robustness of the results. In addition, even islands without permanent inhabitants but with thriving summer tourism deserve to be investigated since they represent suitable sites for H2-based seasonal storage application. Finally, since the energy surplus is usually very abundant, integration of local mobility and ferry connection to the mainland can be included in further analysis.

Appendix A

Additional tables and figures

Table A.1: Only-H2 scenario with LPSP=0.

Island	**PV [kW]**	**Wind [kW]**	**FC [kW]**	**EL [kW]**	**H2 [kWh]**
Støttvær	6	383	46	57	6424
Linesøya	116	940	115	219	17 401
Fjøløy	480	1612	268	458	289 812
Selvær	5	260	85	66	13 125
Lurøya	11	1602	228	610	52 429
Møkster	44	353	90	96	17 338
Fjørtofta	5	5103	246	620	43 527
Lepsøya	10	2326	490	1220	146 612
Røst	10	1975	775	757	93 850
Røvær	30	498	143	187	37 831
Skrova	86	1072	302	235	39 050
Værøya	239	2799	947	981	177 023

Table A.2: Optimal tilt and azimuth angles.

Island	Tilt angle	Azimuth angle
Linesøya	48	0
Fjøløy	47	3
Selvær	49	2
Lurøya	49	1
Møkster	42	4
Fjørtofta	48	2
Lepsøya	47	2
Røst	50	4
Røvær	42	4
Skrova	50	1
Værøya	50	3

Table A.3: H2-battery scenario with LPSP=0.5

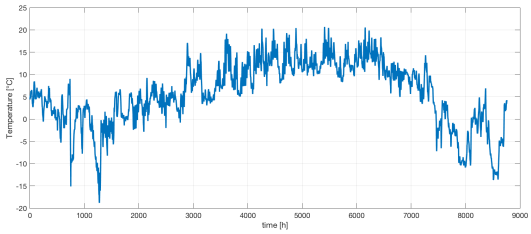
Island	PV [kW]	Wind [kW]	FC [kW]	EL [kW]	H2 [kWh]	Bat [kWh]
Støttvær	2	320	27	55	6973	94
Linesøya	118	805	86	136	11 600	537
Fjøløy	964	1148	262	402	115 535	1171
Selvær	7	260	61	62	9306	86
Lurøya	5	1540	162	577	48 118	10
Møkster	35	326	69	96	14 470	130
Fjørtofta	5	3706	213	349	21 937	1253
Lepsøya	10	2144	359	1166	144 407	68
Røst	88	1888	520	757	70 201	108
Røvær	2	515	117	192	27 900	185
Skrova	112	1040	190	236	33 300	10
Værøya	38	2901	733	903	152 983	23

Table A.4: Only-H2 scenario with LPSP=0.5

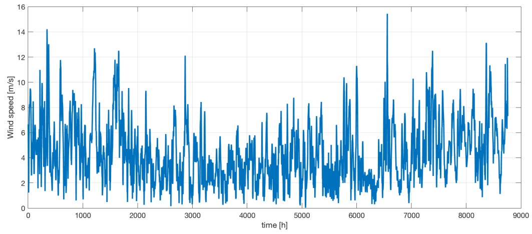
Island	PV [kW]	Wind [kW]	FC [kW]	EL [kW]	H2 [kWh]
Støttvær	5	345	29	56	7268
Linesøya	119	922	115	226	17 452
Fjøløy	496	1510	261	497	172 217
Selvær	7	255	59	65	10 653
Lurøya	5	1600	166	533	47 803
Møkster	45	344	68	97	14 243
Fjørtofta	49	4442	216	446	23 473
Lepsøya	10	2294	352	1070	140 647
Røst	65	2095	503	621	71 381
Røvær	2	484	112	191	32 912
Skrova	109	1069	193	219	33 597
Værøya	57	2770	737	963	157 160

Table A.5: Only-battery scenario with LPSP=0.5

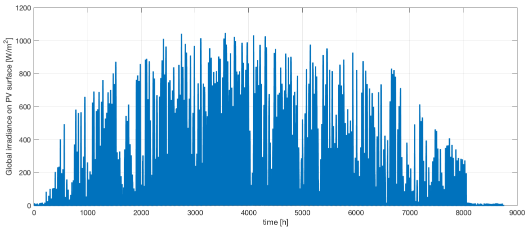
Island	PV [kW]	Wind [kW]	Battery [kWh]
Støttvær	19	485	1280
Linesøya	267	1020	3230
Fjøløy	3800	861	7137
Selvær	8	641	2647
Lurøya	5	3011	7254
Møkster	285	636	2237
Fjørtofta	506	3309	7424
Lepsøya	85	5340	19 343
Røst	198	5252	10 750
Røvær	444	1240	7310
Skrova	487	1920	4040
Værøya	655	7110	17 273



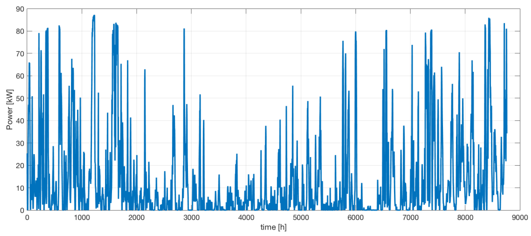
(a) *Ambient temperature*



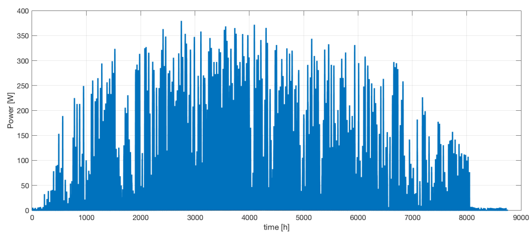
(b) *Wind speed*



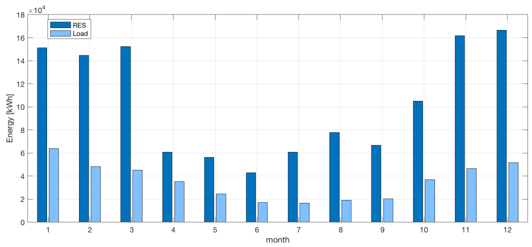
(c) *Solar radiation*



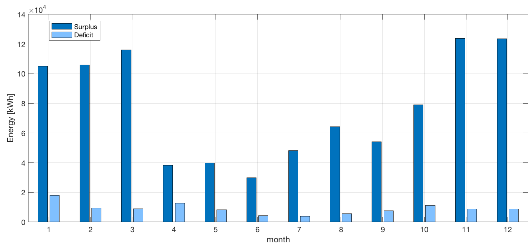
(d) *Wind power production*



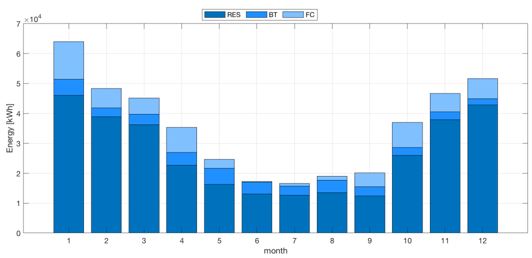
(e) *PV power production*



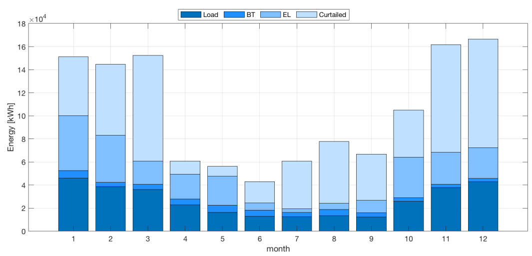
(f) *RES and load*



(g) *Surplus and deficit*

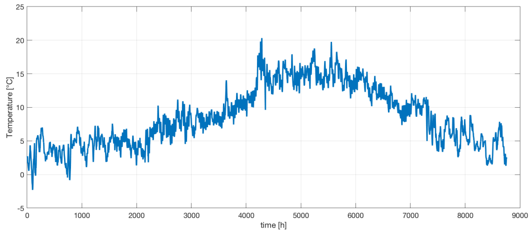


(h) *Load supply segmentation*

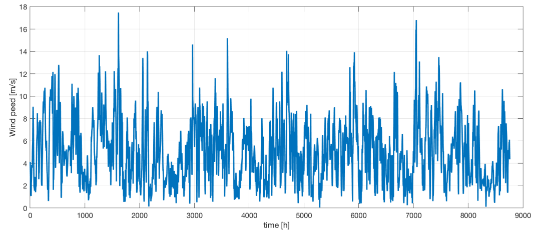


(i) *RES segmentation*

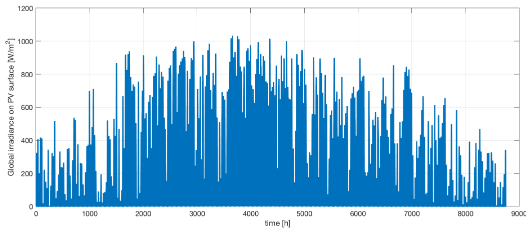
Figure A.1: Linesøya meteorological data, RES production and energy balances.



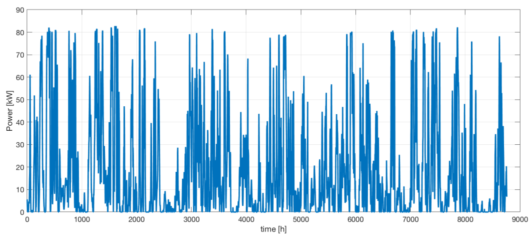
(a) *Ambient temperature*



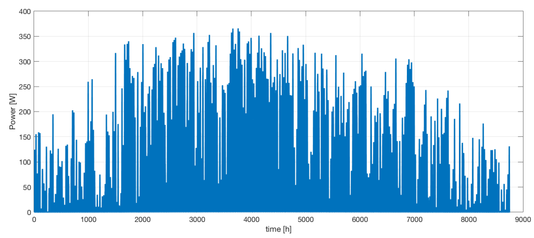
(b) *Wind speed*



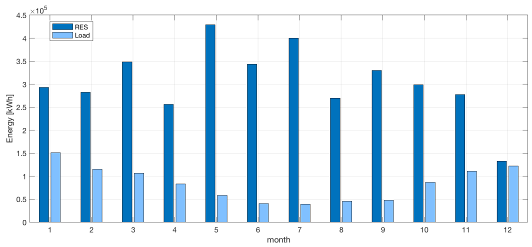
(c) *Solar radiation*



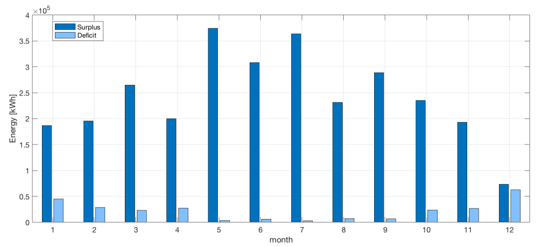
(d) *Wind power production*



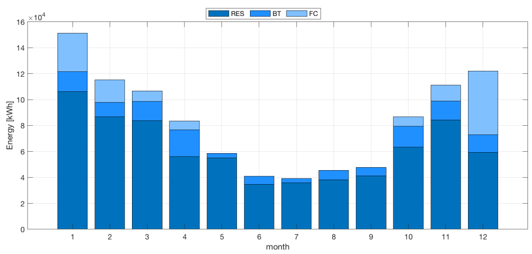
(e) *PV power production*



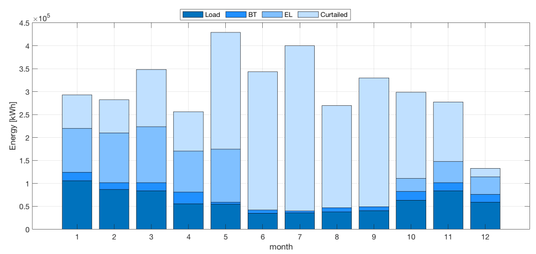
(f) *RES and load*



(g) *Surplus and deficit*

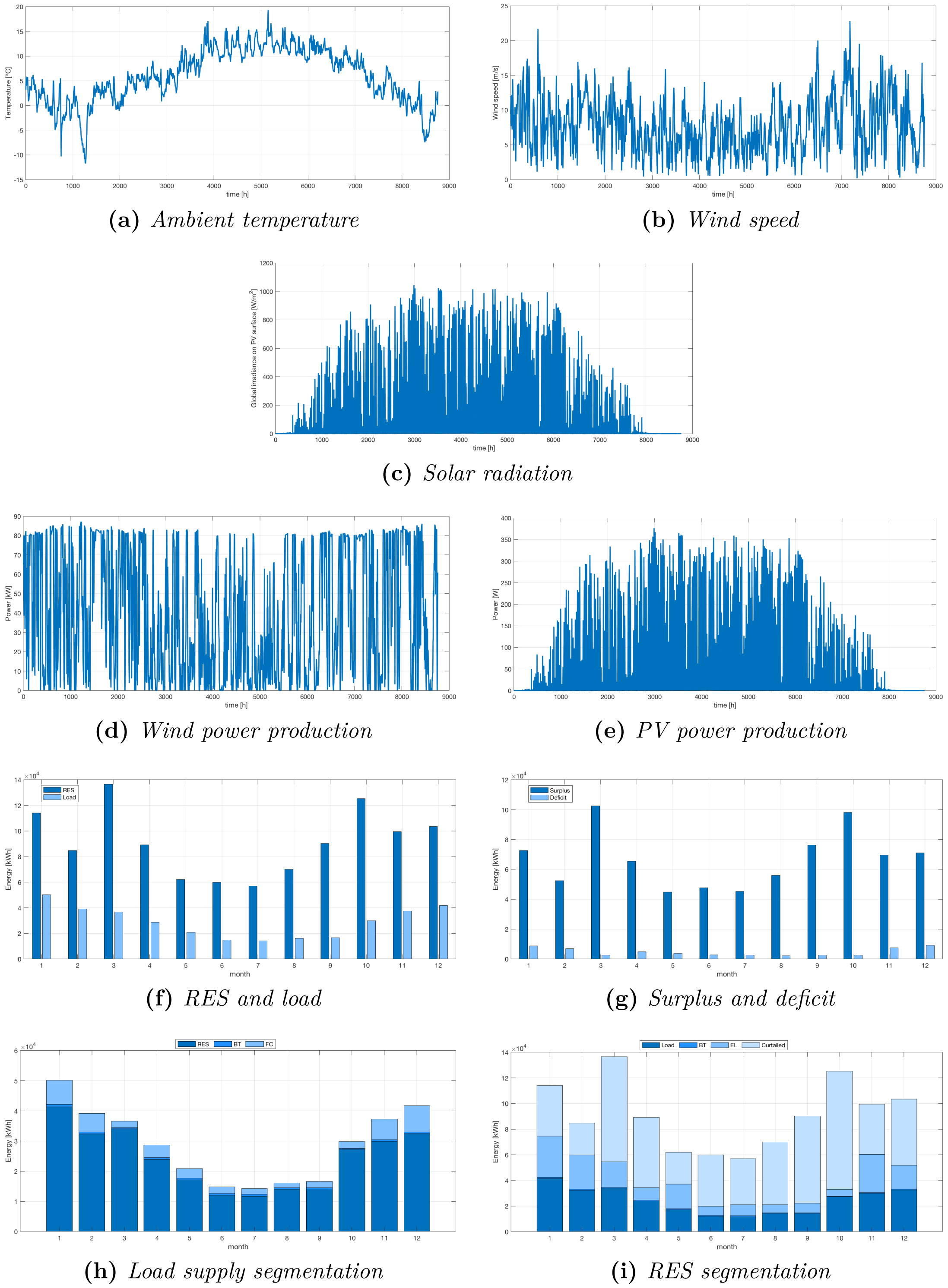


(h) *Load supply segmentation*



(i) *RES segmentation*

Figure A.2: Fjøløy meteorological data, RES production and energy balances.



(a) *Ambient temperature*

(b) *Wind speed*

(c) *Solar radiation*

(d) *Wind power production*

(e) *PV power production*

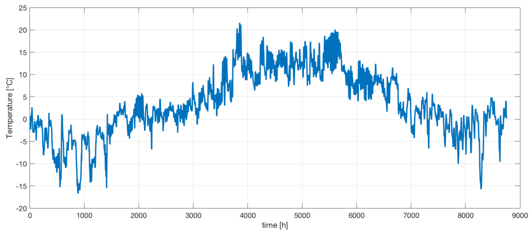
(f) *RES and load*

(g) *Surplus and deficit*

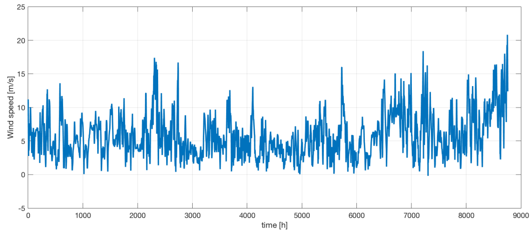
(h) *Load supply segmentation*

(i) *RES segmentation*

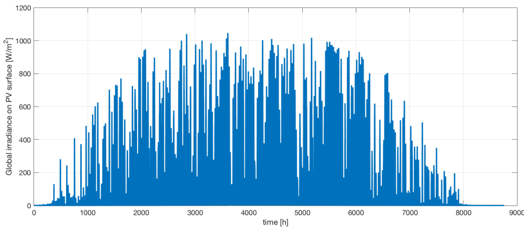
Figure A.3: Selvær meteorological data, RES production and energy balances.



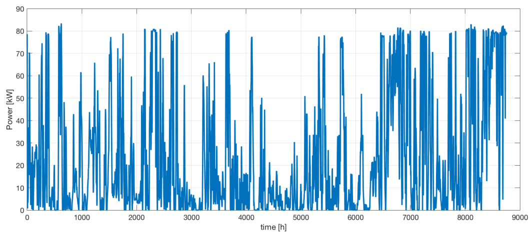
(a) *Ambient temperature*



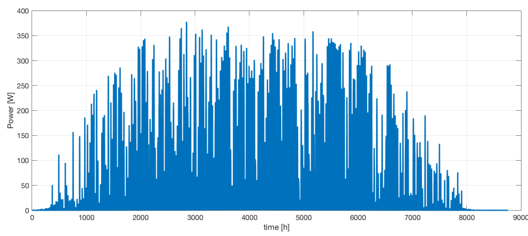
(b) *Wind speed*



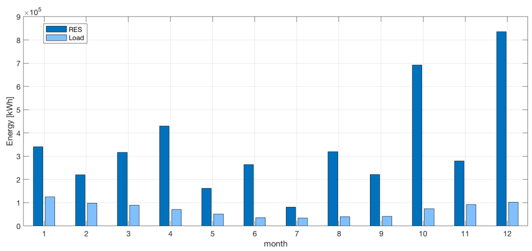
(c) *Solar radiation*



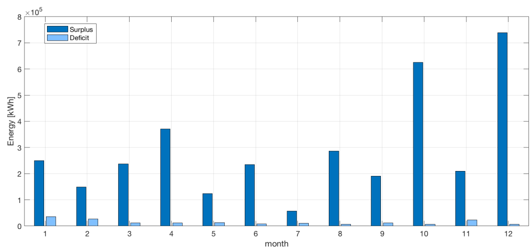
(d) *Wind power production*



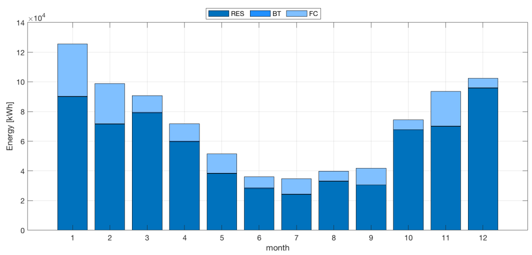
(e) *PV power production*



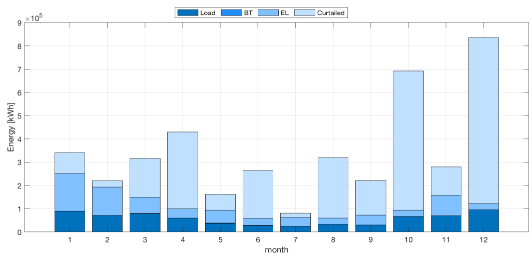
(f) *RES and load*



(g) *Surplus and deficit*

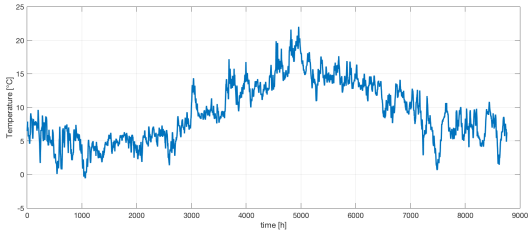


(h) *Load supply segmentation*

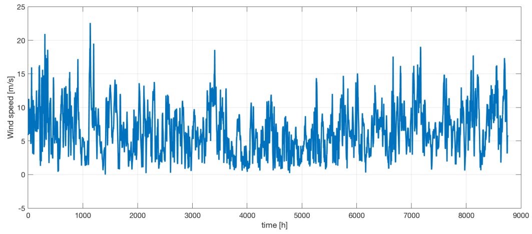


(i) *RES segmentation*

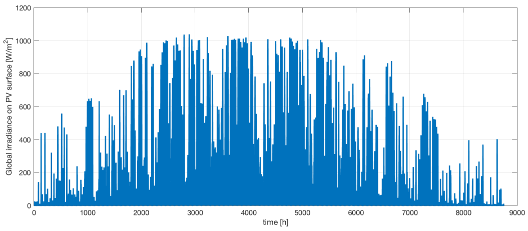
Figure A.4: Lurøya meteorological data, RES production and energy balances.



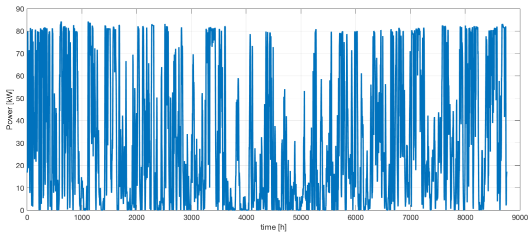
(a) *Ambient temperature*



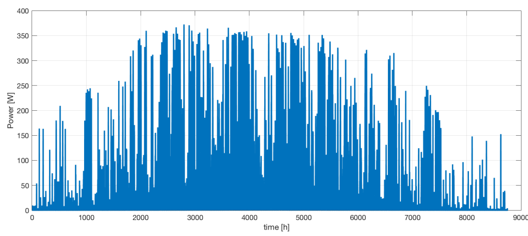
(b) *Wind speed*



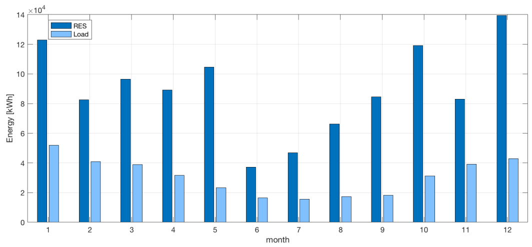
(c) *Solar radiation*



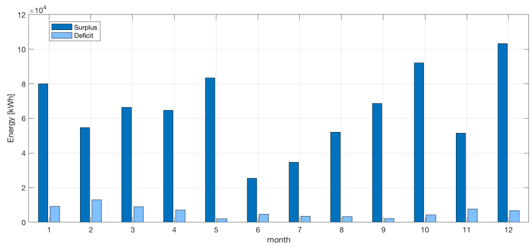
(d) *Wind power production*



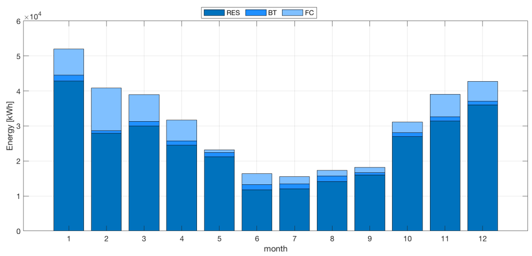
(e) *PV power production*



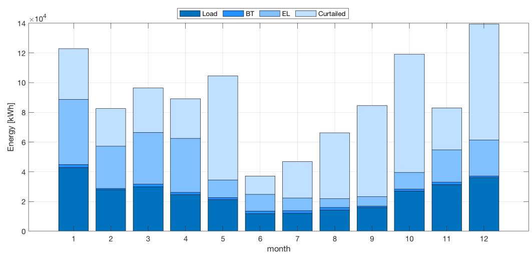
(f) *RES and load*



(g) *Surplus and deficit*

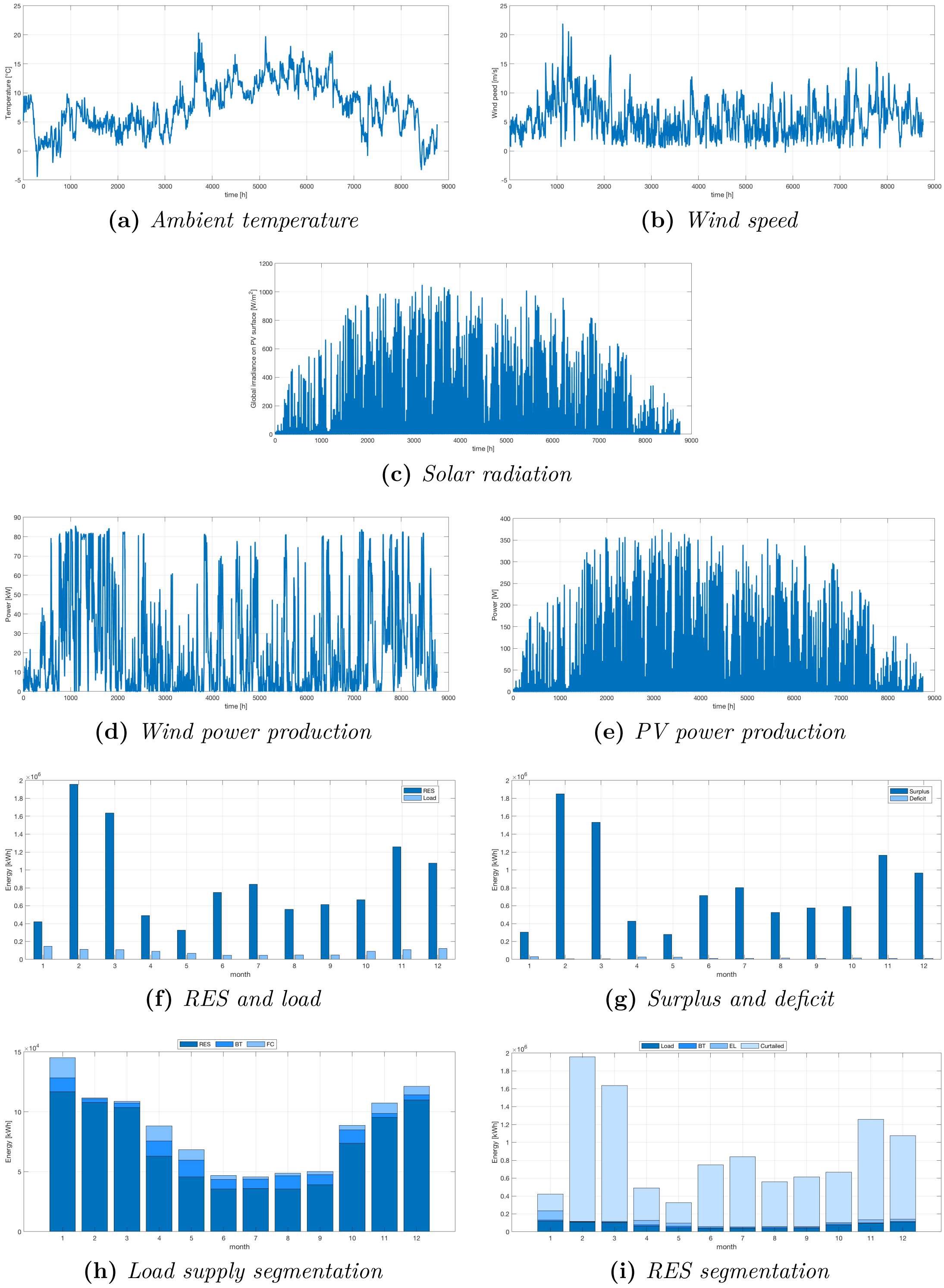


(h) *Load supply segmentation*



(i) *RES segmentation*

Figure A.5: Møkster meteorological data, RES production and energy balances.



(a) *Ambient temperature* **(b)** *Wind speed*

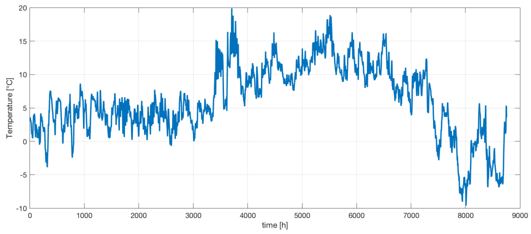
(c) *Solar radiation*

(d) *Wind power production* **(e)** *PV power production*

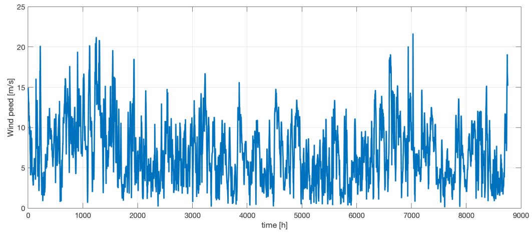
(f) *RES and load* **(g)** *Surplus and deficit*

(h) *Load supply segmentation* **(i)** *RES segmentation*

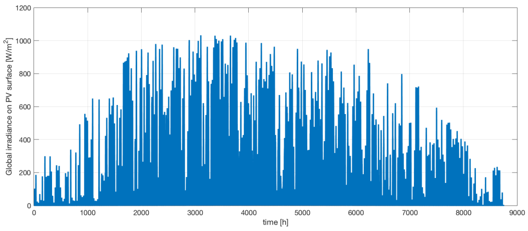
Figure A.6: Fjørtofta meteorological data, RES production and energy balances.



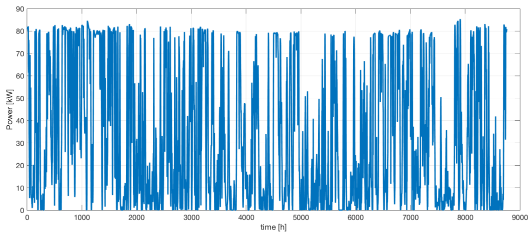
(a) *Ambient temperature*



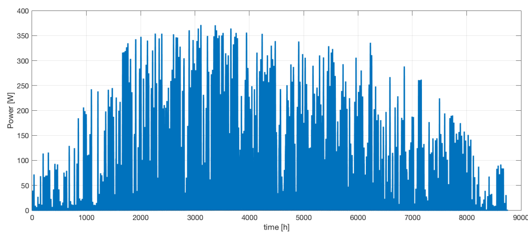
(b) *Wind speed*



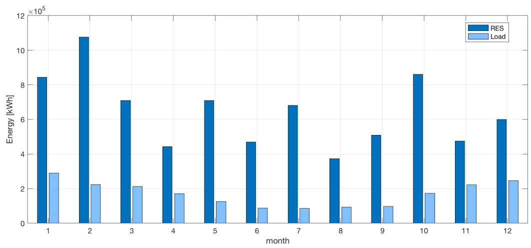
(c) *Solar radiation*



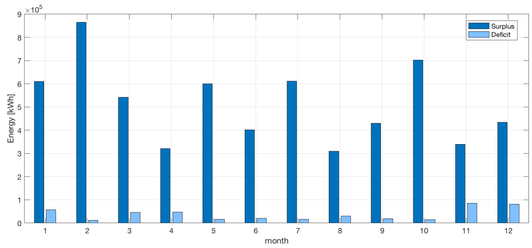
(d) *Wind power production*



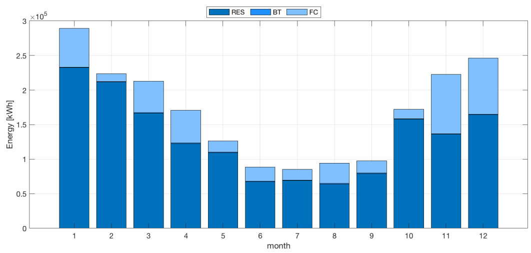
(e) *PV power production*



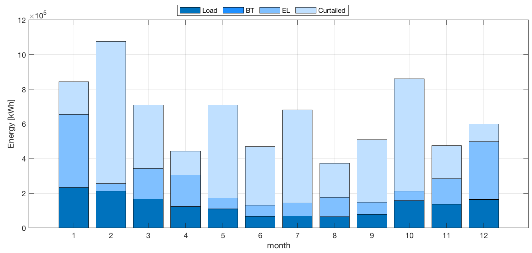
(f) *RES and load*



(g) *Surplus and deficit*

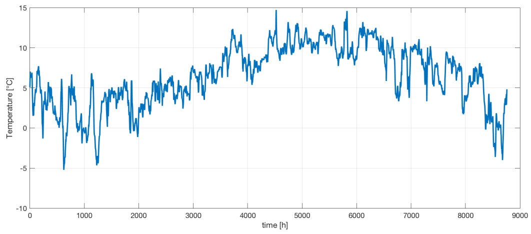


(h) *Load supply segmentation*

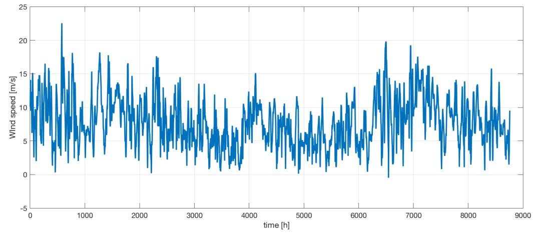


(i) *RES segmentation*

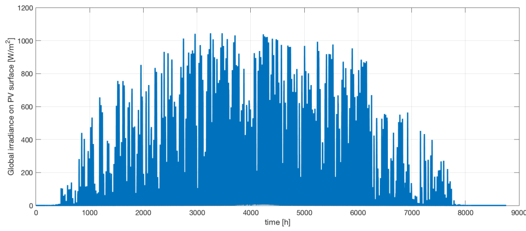
Figure A.7: Lepsøya meteorological data, RES production and energy balances.



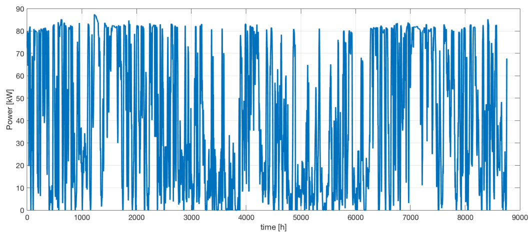
(a) *Ambient temperature*



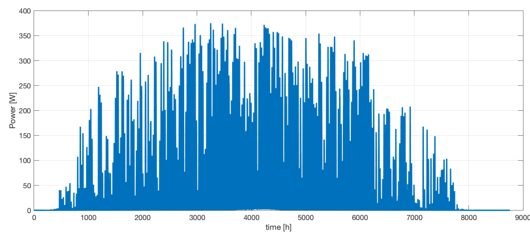
(b) *Wind speed*



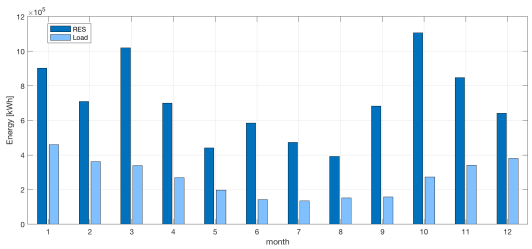
(c) *Solar radiation*



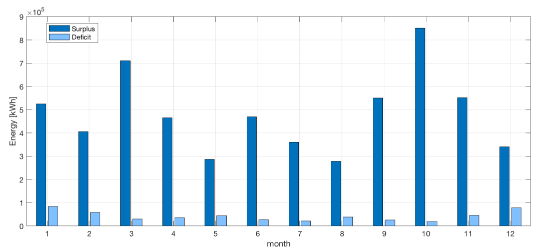
(d) *Wind power production*



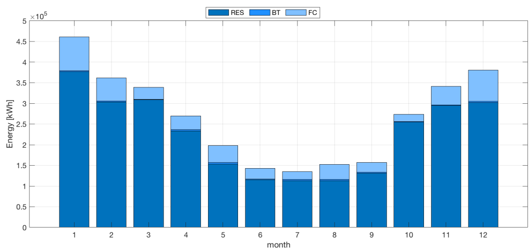
(e) *PV power production*



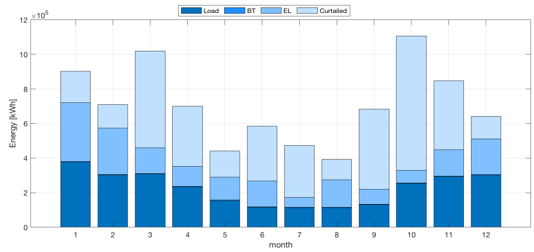
(f) *RES and load*



(g) *Surplus and deficit*

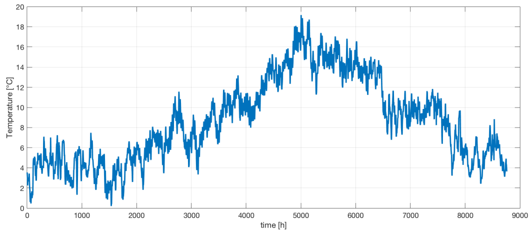


(h) *Load supply segmentation*

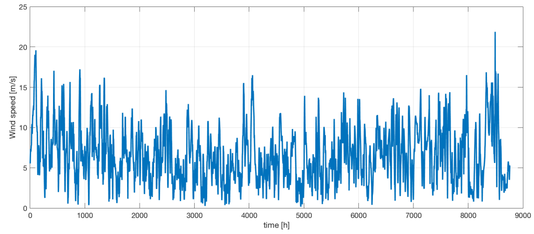


(i) *RES segmentation*

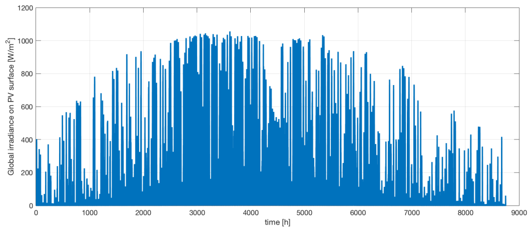
Figure A.8: Røst meteorological data, RES production and energy balances.



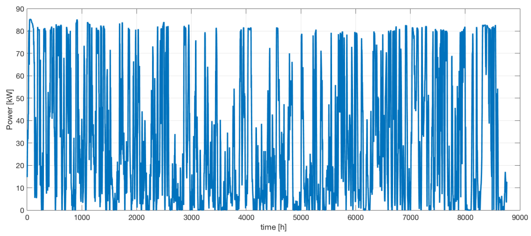
(a) *Ambient temperature*



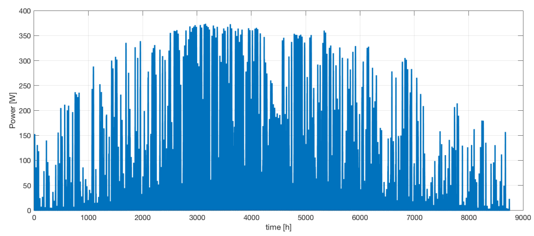
(b) *Wind speed*



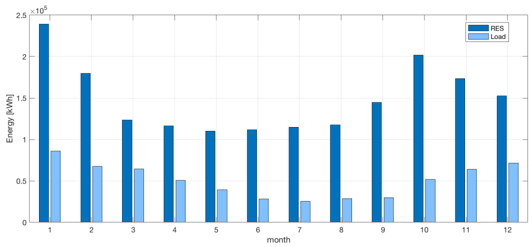
(c) *Solar radiation*



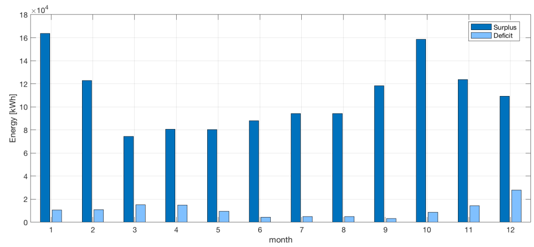
(d) *Wind power production*



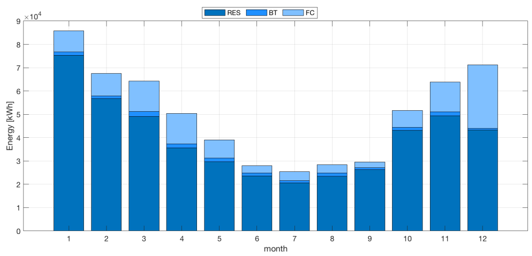
(e) *PV power production*



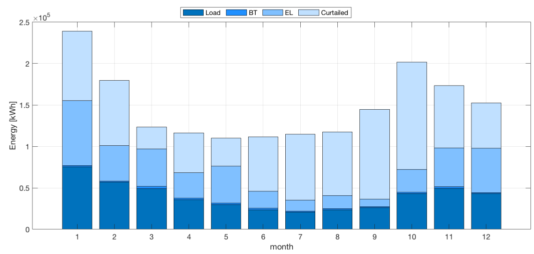
(f) *RES and load*



(g) *Surplus and deficit*

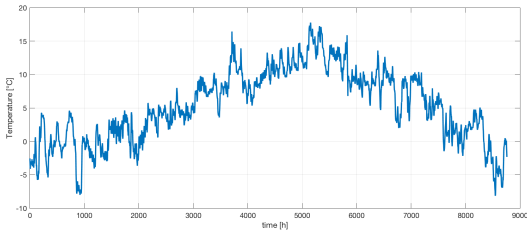


(h) *Load supply segmentation*

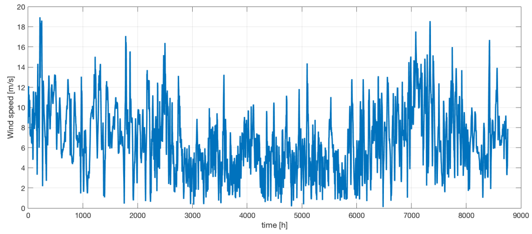


(i) *RES segmentation*

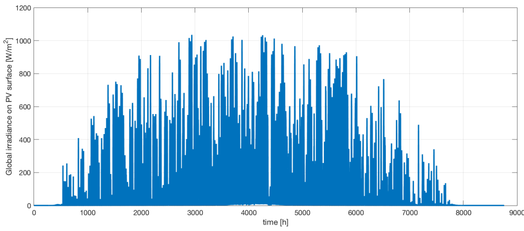
Figure A.9: Røvær meteorological data, RES production and energy balances.



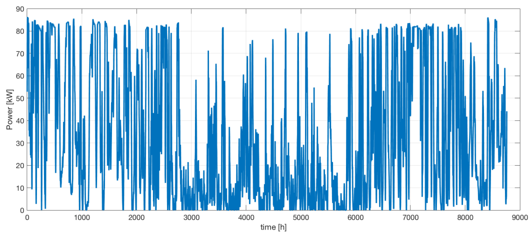
(a) *Ambient temperature*



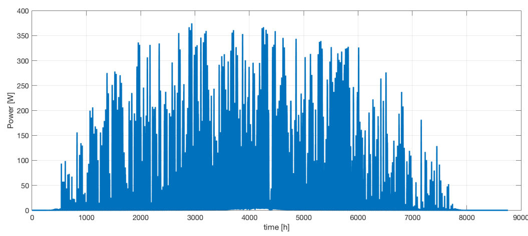
(b) *Wind speed*



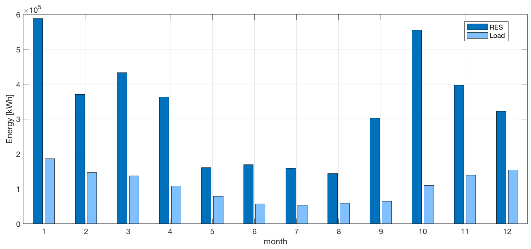
(c) *Solar radiation*



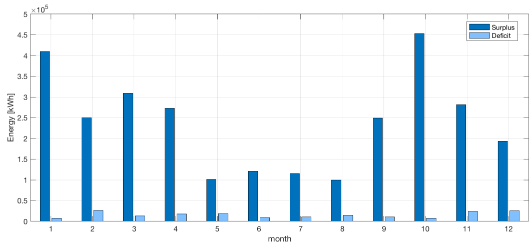
(d) *Wind power production*



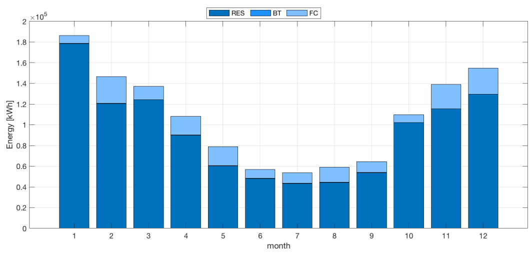
(e) *PV power production*



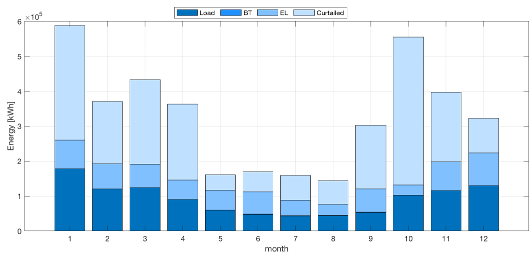
(f) *RES and load*



(g) *Surplus and deficit*

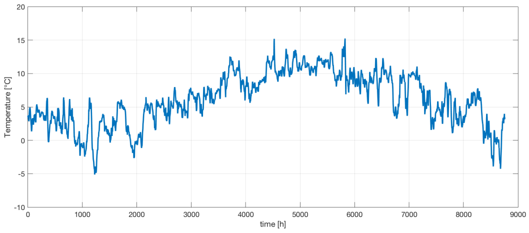


(h) *Load supply segmentation*

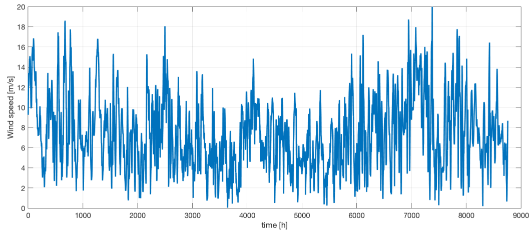


(i) *RES segmentation*

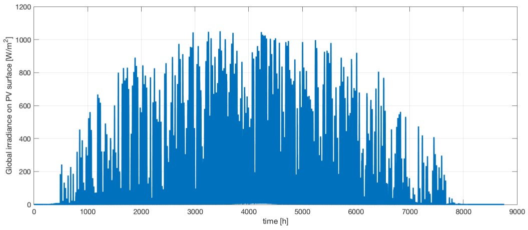
Figure A.10: Skrova meteorological data, RES production and energy balances.



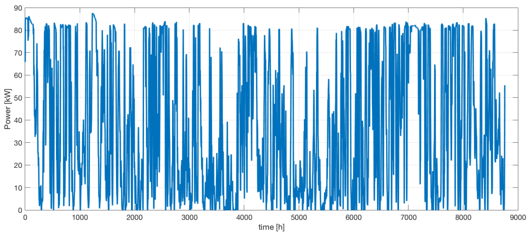
(a) *Ambient temperature*



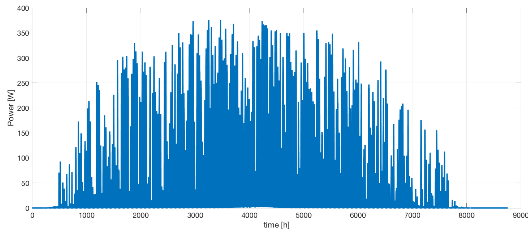
(b) *Wind speed*



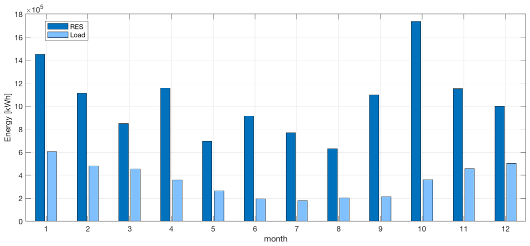
(c) *Solar radiation*



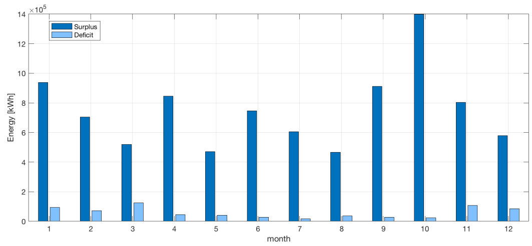
(d) *Wind power production*



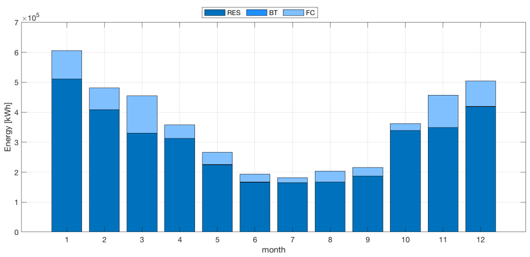
(e) *PV power production*



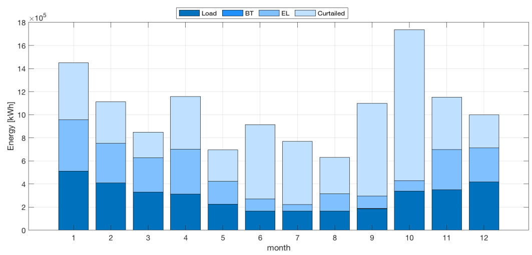
(f) *RES and load*



(g) *Surplus and deficit*

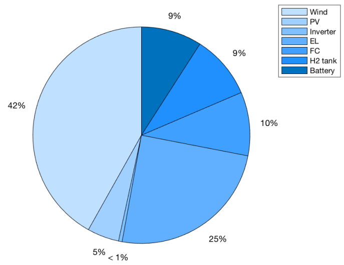


(h) *Load supply segmentation*

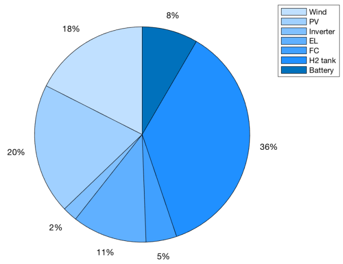


(i) *RES segmentation*

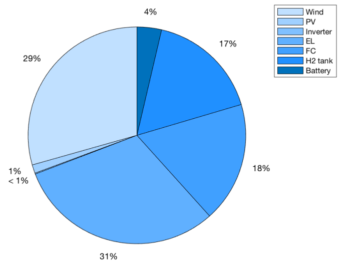
Figure A.11: Værøya meteorological data, RES production and energy balances.



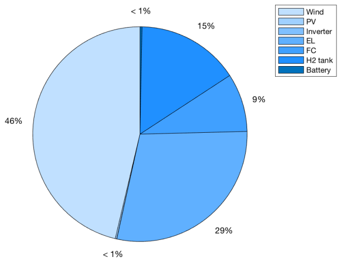
(a) *Linesøya*



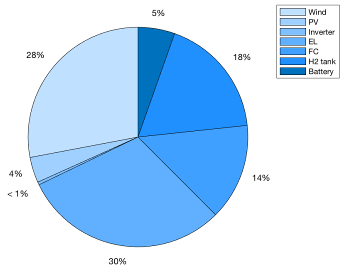
(b) *Fjøløy*



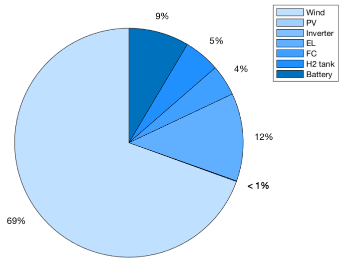
(c) *Selvær*



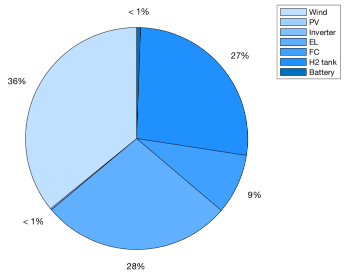
(d) *Lurøya*



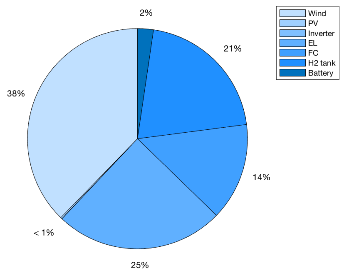
(e) *Møkster*



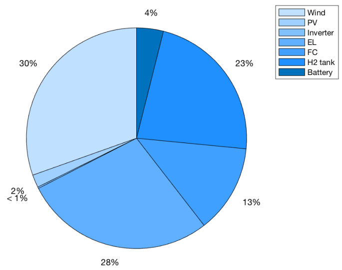
(f) *Fjørtofta*



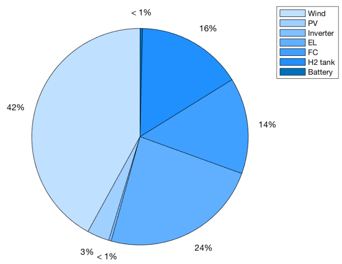
(g) *Lepsøya*



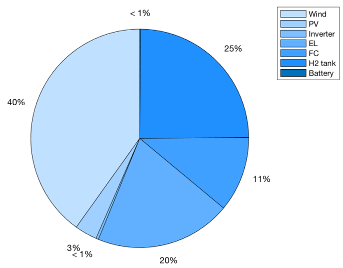
(h) *Røst*



(i) *Røvær*



(j) *Skrova*



(k) *Værøya*

Figure A.12: LCOE breakdowns.

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