PROVINCIA AUTONOMA DI TRENTO

agenzia provinciale per le risorse idriche e l'energia

RAPPORTO TECNICO

AMETHyST

PIANO ENERGETICO AMBIENTALE PROVINCIALE 2021-2030

07

ANALISI DI FATTIBILITÀ E PROGETTAZIONE PRELIMINARE DI UN SISTEMA PER LA PRODUZIONE DI IDROGENO IN DIVERSI SCENARI DI COMUNITÀ ALPINE

AGOSTO 2024

AGENZIA PROVINCIALE PER LE RISORSE IDRICHE E L'ENERGIA
ufficio studi e pianificazione delle risorse energetiche
Sede: Piazza Fiera, 3 - 38122 a Trento
Telefono: 0461.497310 Fax: 0461.497301
www.energia.provincia.tn.it
Email: aprie@provincia.tn.it (PEC) :aprie@pec.provincia.tn.it

SAPIENZA
UNIVERSITÀ DI ROMA

FEASIBILITY DESIGN AND PRELIMINARY ANALYSIS OF A HYDROGEN PRODUCTION SYSTEM IN DIFFERENT ALPINE COMMUNITY SCENARIOS

Provincia di Trento

DIPARTIMENTO DI INGEGNERIA
MECCANICA E AEROSPAZIALE

SAPIENZA
UNIVERSITÀ DI ROMA

Version no 2 of April, the 12th, 2024

Prof. Domenico Borello
Prof. Luca Cedola
Ing. Mario Di Veroli
Ing. Alessandro Caravelli
Ing. Adriano Pozzessere

File name: Trento Project _EN_rev2

Summary

1 Introduction 5

1.1 Methodology of analysis 6

1.2 Analysis of environmental context and energy needs 6

1.3 Fabbisogni termici e dati di input .... Error! Bookmark not defined.

1.4 Self-production systems assumptions 7

1.5 Performance indicators 8

2 Analysis of territorial and energy context 9

2.1 Substitution of heat pumps 9

2.1.1 Analysis of heat pump performance in Trentino municipalities. 9
2.1.2 Replacement of existing generators with heat pumps 12
2.1.3 Scenario of generator replacement and energy upgrading 13
2.1.4 Detailed analysis of heat pump installations in five Trentino municipalities 13
2.1.5 Results presentation and comment 14
2.1.6 Detailed analysis of heat pump systems with advanced management 18
2.1.7 Conclusions 20

2.2 Planning natural gas distribution service extension 21

2.2.1 Specific objectives and assumptions 23
2.2.2 Current gas network characteristics and analysis of criticalities 24
2.2.3 Identification of the potential natural gas distribution network extension 26
2.2.4 Method and analysis carried out for distribution service planning purposes 28
2.2.5 The first pillar: compatibility scenarios between potential expansion of the natural gas distribution network and provincial decarbonization goals 29
2.2.6 Heat demand 33
2.2.7 Hydrogen demand 35

2.3 Methanization of the western areas of Trentino 36

2.3.1 Green hydrogen in Trentino to 2030 40

2.4 Provincial decarbonization scenarios to 2030 - Water source forecast scenarios. 42

2.4.1 Status of nominal powers and hydropower production 43
2.4.2 Reallocation of large water derivation concessions for hydroelectric purposes 44
2.4.3 Possible changes on hydropower production at the same derived flow rate 45
2.4.4 Effects of climate change on hydropower generation 46
2.4.5 Update of the Water Protection Plan 47
2.4.6 Prevailing and competing uses 49
2.4.7 New hydroelectric derivation concessions 50

2.4.8 Economic optimization of plants and energy storage: pumping systems ... 51
2.4.9 Conclusions ... 51
3 Development of an integrated solution and identification of technologies and works required to realize the project in relation to the spatial context ... 53
3.1 Analysis of possible sources ... 53
3.2 Background and assessments of Wind Energy ... 53
3.3 Background and assessments on Hydropower ... 54
3.4 Background and assessments on photovoltaic ... 55
4 System Layout ... 56
5 System Modeling ... 62
5.1 Softwares adopted ... 62
5.2 System Global Model ... 62
5.3 Unit sizing and Simulation parameters ... 63
5.3.1 PV Plant ... 63
5.3.2 Electrolyzer ... 64
5.3.3 Buffer Storage section ... 65
5.3.4 Long-term Storage Section ... 66
5.3.5 End-user Section ... 69
5.4 Control Logic ... 69
6 Analysis of Scenario n°1 ... 72
6.1 Infrastructure Description ... 72
6.1.1 Site Location ... 72
6.1.2 Layout ... 73
6.2 Sizing and Simulation parameters ... 74
6.2.1 Main parameters ... 74
6.2.2 Unit Parameters ... 75
6.3 Simulation Results ... 77
7 Analysis of Scenario n°2 ... 79
7.1 Infrastructure Description ... 79
7.1.1 Site Location ... 79
7.1.2 Layout ... 80
7.2 Sizing and Simulation parameters ... 80
7.2.1 Main parameters ... 80

7.2.2 Unit parameters 81

7.3 Simulation Results 84

8 Analysis of Scenario n° 3 86

8.1 Infrastructure Description 86

8.1.1 Site Location 86

8.1.2 Layout 87

8.2 Sizing and Simulation parameters 87

8.2.1 Main parameters 87

8.2.2 Unit parameters 88

8.3 Simulation results 90

9 Technical and Economic feasibility assessment of the project 92

9.1 Cost Assessment 92

9.2 Land occupation 97

9.3 Comparative analysis 97

9.3.1 CO2/MWh yearly comparison with fossil source 97

9.3.2 Cost comparison €/MWh with fossil source 99

10 Risk Analysis related to Project realization 100

11 Estimation of environmental impacts in terms of reduction of pollutant and climate-altering emissions 104

12 Analysis of the replicability and scalability conditions of the pilot project on the territory of Trentino and the Alps 104

Foreword

This document is prepared as part of a contract between the Department of Mechanical and Aerospace Engineering at Sapienza University of Rome and the Provincial Agency for Water Resources and Energy the Director General of Trento.

1 Introduction

This paper aims to explore the application of different energy carriers and technologies to increase the sustainability of Communities.

Given the winter temperatures, heat generation systems from electric carrier (heat pump) do not have optimal performance and often do not guarantee the operation and operation of equipment in the design operating ranges.

In the thermal season, the territory of the Province of Trento is characterized by very cold outdoor temperatures averaging -5 / -10 °C.

Such external conditions do not allow the use of heat pumps, which, on the other hand, for temperatures slightly above 0°C are particularly performing.

This consideration, combined with the desire to use renewable sources and focus on technologies that do not emit climate-changing gases (decarbonization), leads to the identification of Green Hydrogen as a potential energy carrier for residential thermal uses.

In addition to purely energy and technical considerations, KPIs are also examined by analyzing them and aspects related to the territorial context on which the plants will be located (Land consumption, CO2 emission reduction, etc.).

In general, the following aspects (detailed below) will be considered in the scenario analysis:

- Type of utilities to be supplied;
- Current thermal power generation systems;
- Background of energy carrier distribution infrastructure;
- Availability of renewable energy resources;
- Any constraints for land protection and preservation.

The previous aspects led to the identification of No. 3 potential scenarios for the use of green hydrogen. The scenarios identified and their municipalities of application are the following:

- Peio: Hydrogen production and modeling of a dedicated network for direct supply of hydrogen-fueled residential heat generators. Reference municipality where there is no natural gas network.

- Ronzo Chienis: Hydrogen production for blending input into existing natural gas grid. Reference municipality.
- San Martino di Castrozza: Hydrogen production for feeding district heating plant currently serving residential thermal users. Reference municipality already equipped with district heating plant.

The first part of the study is aimed at identifying the renewable technology best suited to the energy-territory context and building a Simulink model; then, for the three scenarios, the energy needs were defined.

Based on the energy requirements, the amount of hydrogen needed for each Scenario was then calculated; this figure was necessary to determine the electricity to be produced by the renewable source for generation to feed the electrolyzer.

Buffer and storage were verified and sized to compensate for the mismatch between the energy availability of the renewable resource and the energy demand.

1.1 Methodology of analysis

For the sizing of hydrogen production, distribution and storage systems, reference was made to data provided by the Province of Trento and from statistical climate data.

Based on energy-environmental considerations and other design constraints, photovoltaic technology was identified as the only source for green hydrogen production.

Based on the data provided and by means of a load curve estimated based on outdoor temperatures, the power of the photovoltaic generator was sized. The power was sized to meet a percentage share of the total demand, assuming a real scale of applicability of the system. Starting from a baseline value of the photovoltaic generator power, it was possible to proceed to a numerical simulation phase using Simulink software, which allowed to validate the results and size the buffer and seasonal storage.

This simulation was prepared for the three scenarios under study.

The output of the photovoltaic generators was also evaluated on the basis of a demand coverage factor that was evaluated in relation to the three scenarios.

1.2 Analysis of environmental context and energy needs

The environmental context in which the systems should be realized is an alpine setting with cold outdoor temperatures. As already anticipated, in such contexts heat pumps are practically unusable.

Chapter 2 details the spatial and energy context of the province of Trento.

1.3 Thermal demand and input data

The input data provided by the Province of Trento and assumed for plant sizing were:

- **Peio**: List of domestic generators with relative power rating and fuel type (LPG, wood chips, diesel, pellets); the capacity of the district heating plant in the hamlet of Cogolo di Peio and the related annual consumption of the plant; the consumption of domestic generators. To calculate energy requirements, it was assumed that domestic boilers operate at the same number of hours as district heating. Consumption estimates were derived based on the temperature difference between indoor conditions (20 °C) and the average outdoor temperature.

- **Ronzo - Chienis**: List of domestic generators and their power rating and fuel type. Since the absence of district heating, to calculate the energy demand it was assumed that domestic boilers operate the same number of hours as district heating in Peio (Cogolo di Peio). Consumption by domestic generators was not provided. Consumption estimates were derived based on the temperature difference between indoor conditions (20 °C) and the average outdoor temperature.

- **San Martino di Castrozza**: there are no domestic generators, and reference was made to data provided on the power output of the generators and consumption in terms of primary energy expressed in TOE (Tons of Oil Equivalents-both from diesel fuel and wood chips).

1.4 Self-production systems assumptions

The renewable resource was sized taking into consideration the following factors:

- On-site availability of the energy resource;
- Available areas;
- Environmental and landscape constraints.

The following energy sources were considered:

- Solar PV;
- Wind Power;
- Hydropower.

1.5 Performance indicators

In order to compare the results with standard technologies and evaluate the project from a technical/economic point of view, some performance indicators (KPIs) have been defined that relate energy saving aspects to environmental impact aspects and economic aspects.
The indicators designed for project analysis are:

- CO_2 equivalent emissions compared to fossil source (CO_2 equivalent/MWh);
- Energy cost €/MWh_t ;
- Soil consumption that relates the occupied area of the PV plants to the production of electricity required for H_2 production.

2 Analysis of territorial and energy context

This chapter provides excerpts and summaries of the "PIANO ENERGETICO AMBIENTALE PROVINCIALE 2021-2030 (PEAP) della provincia di Trento".

(https://www.provincia.tn.it/content/download/62137/1010233/file/PEAP_2021_2030_.pdf)

2.1 Substitution of heat pumps

In view of the push towards an increasing electrification of consumption for winter air conditioning, also due to their decarbonization through the use of renewable sources, this chapter is aimed at verifying the value in the provincial territory of the use of air-water heat pumps for heating and domestic hot water production. What is presented in this chapter follows the evidence of the previous one, "Scenario of energy upgrading of residential buildings in Trentino," by screening in detail the potential of installing heat pumps as a replacement for technologies to date more usual.

The methodology involves first assessing the performance of air-to-water heat pumps in the Trentino region.

Next, the scenarios analyze a potential generator replacement without the intervention on the existing envelope and then the potential performance of heat pumps in the case of buildings that have been energy upgraded, and thus affected by opaque envelope improvements and window replacement.

Said methodology has been tested on some representative municipalities in Trentino so as to understand the real behavior of heat pump systems also in relation to the installation of thermal storage for both domestic hot water production and space heating. With this detailed analysis, in addition to a better representation of the building-plant system, it is also possible to evaluate the potential self-consumption of the photovoltaic energy produced in situ, thus assessing the real electrical absorption from the grid, as well as through the use of "rule-based" regulation logics.

Referring to Technical Annexes No. 4, 5 and 6 of the plan for full description, we report sufficient details for reading the main results.

2.1.1 Analysis of heat pump performance in Trentino municipalities.

To evaluate the effectiveness of replacing heat generators currently used in building heating systems with air-to-water heat pumps, it is essential to understand the expected performance in different municipalities of the Province. In fact, heat pumps have a coefficient of performance (COP) that is sensitive to changes in the temperature of cold (outside air) and hot (heating system water) sources. While the temperature of the hot source can be assumed to vary according to the characteristics of the building envelope and the emission terminals, the temperature of the cold source is closely related to the municipality analyzed and thus to its elevation.

In the first phase, therefore, the simplified calculation of a heat pump system was implemented for each of the 175 municipalities in Trentino, also varying the building characteristics both in terms of building type (single-family, terraced house, medium apartment building, and large apartment building) and by age of construction and thus age class. In particular, for the analysis of the mere replacement of generators with heat pumps, it can be assumed that this is possible only on relatively recent buildings for which energy calculations have been carried out during building design. For this reason, the study focuses on the age classes following the enactment of Law No. 373/76, which first introduced constraints on the design, installation, operation and maintenance of thermal systems and requirements for the thermal insulation of buildings. The age classes analyzed are therefore V5, buildings constructed from 1976 to 1990, V6 (1991 to 2005) and V7 (after 2005).

The results of the analysis conducted are the trends in seasonal coefficients of performance (SCOP), i.e., the ratio of the annual thermal energy output from the heat pump to meet heating and domestic hot water demands, compared to the annual electrical energy absorbed by the heat pump and any backup heater. These values were obtained for all municipalities in Trentino, for different building types and age classes. The following graphs show the SCOP trends of the optimal heat pump sizes as the altitude of the municipality changes for both stand-alone and centralized system configurations. A SCOP threshold of 2.3 is also highlighted in the graphs. This value was derived by considering the SCOP above which the heat pump has lower primary energy consumption than a condensing boiler with an average seasonal efficiency of 100%.

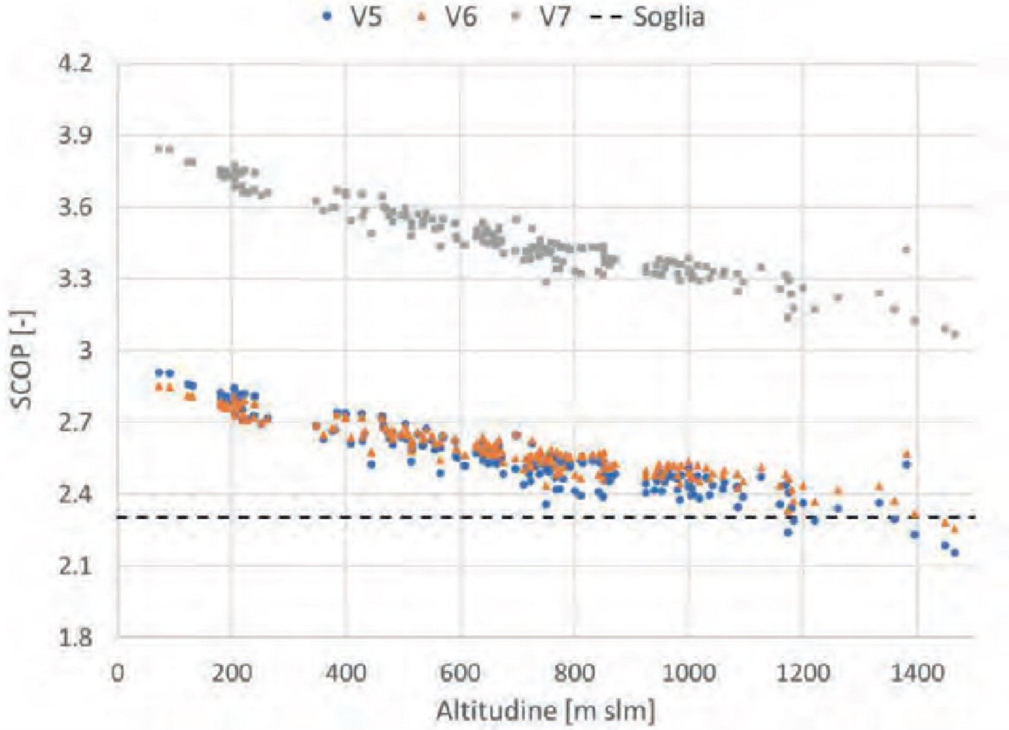


Figure 1. SCOP trend for stand-alone systems in MF buildings.

The figure above shows the SCOP trend as a function of municipality altitude for single-family buildings, a common type in Trentino. It can be seen from the graph that for the age classes V5 and V6, due to the medium-high temperature operation of the heating system, the SCOP is close to the threshold value especially for altitudes above 1000 m. Reducing the supply temperature of the emission terminals of buildings in class V7 leads to significant benefits in terms of SCOP.

Similar trends were obtained for the other building types (townhouse, medium apartment building and large apartment building) in the case of centralized systems, while there was a significant deterioration in the case of stand-alone systems.

The noticeable deterioration in the case of stand-alone systems occurs because the compact shape of the building and the size of individual apartments mean that the smaller size of the heat pump is still oversized relative to the heating demands. As a consequence, therefore, the heat pump often works in on/off mode with a significant degradation in performance. It should be noted, however, that in the simplified analysis carried out, the different dispersions of the distribution circuits are not evaluated in sufficient detail, which, in centralized systems, are certainly greater. Starting from the results just obtained and considering the frequency with which each building is present in each of the Trentino municipalities, it is possible to evaluate an average SCOP of the heat pumps. In the graph we can see that in general for the three age classes considered the average SCOP is higher than the threshold value of 2.3, thus highlighting how replacing the generator with an air-water heat pump is generally an advantageous solution in terms of primary energy savings. As can be seen, however, the advantage is very modest for class V5 and V6 buildings where, the supply temperature of the emission terminals, severely limits the performance of the heat pump. In contrast, the margin of advantage is much greater for buildings in class V7 for which the emission temperature is small. This result thus shows the importance of the combined intervention of generator replacement and building envelope energy efficiency.

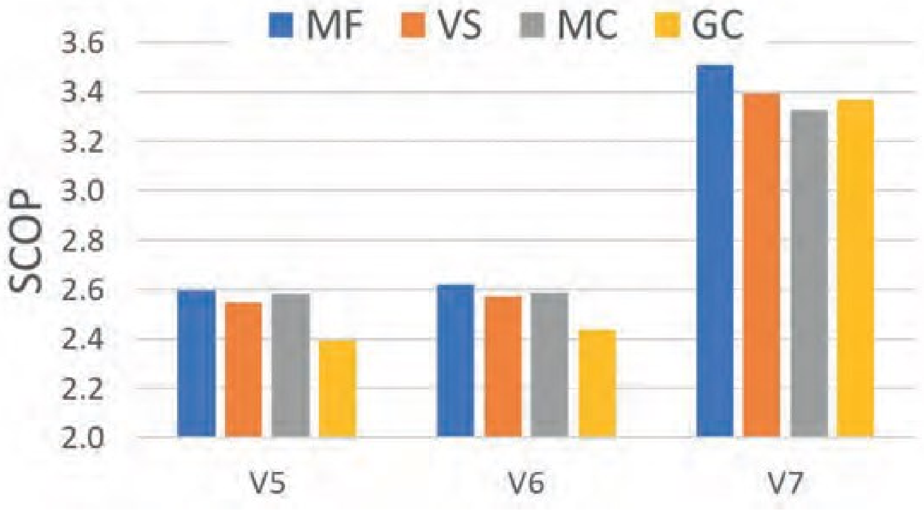


Figure 2. Trends in average SCOP over all municipalities in Trentino.

Therefore, the analysis was repeated in order to evaluate the energy performance of an energy upgraded building. A major first-level renovation leading to an annual useful thermal performance index for heating of 60 kWh m2 was evaluated. In contrast, the useful thermal energy requirement for domestic hot water production was considered unchanged.

The analysis of heat pump performance was then repeated considering whether or not the supply temperature of the emission terminals could be reduced according to the climate curve already adopted for class V7 buildings.

In the figure above, it can be seen that reducing the building's energy demand leads to an improvement in system performance, most markedly for valley bottom municipalities. The most noticeable improvement, however, occurs when the upgrading also allows the flow temperature to the heating system to be reduced.

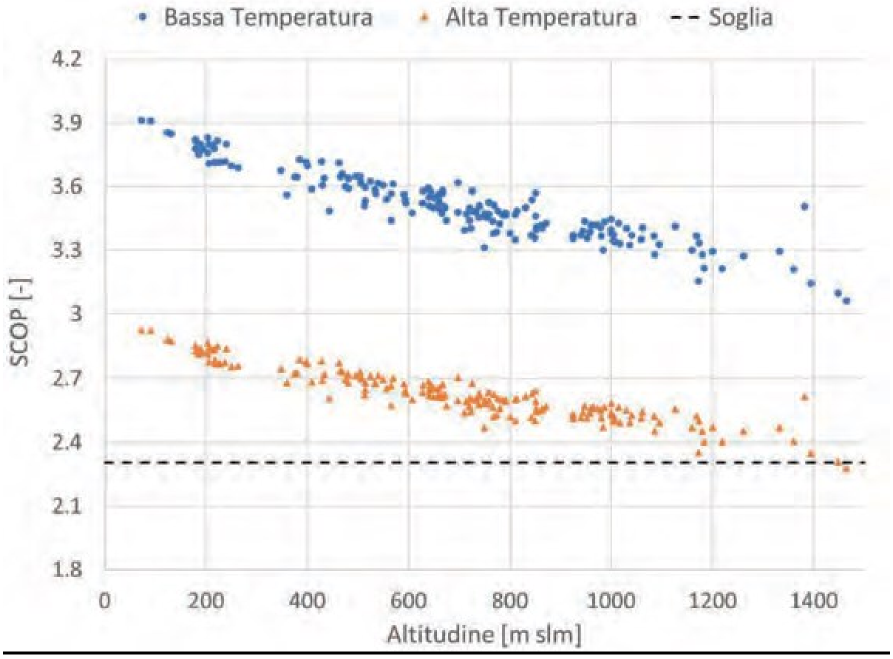


Figure 3. Trends in average SCOP over all municipalities in Trentino.

2.1.2 Replacement of existing generators with heat pumps

Starting from the performance just obtained for all municipalities in Trentino, the potential impact of the mere replacement of all types of existing generators, whether condensing boilers, LPG or split wood/pellet, in buildings belonging to age classes V5, V6 and V7 was assessed.

The change in total primary energy requirement also considered the electrical energy absorbed by heat pumps. For this, the primary energy conversion factors found in the "Minimum Requirements" decree were adopted. For electricity from the grid the factor 2.42 was used, while for residential consumption attributable to the different energy carriers an average factor weighted on the share of requirements covered by the different energy sources was evaluated and thus obtaining a factor of 1.033.

Case	V5	V6	V7	Total

Current Status	21,51	25,40	9,77	56,68
With Heat Pumps	12,06	18,17	5,23	35,46
Variation	-44%	-28%	-46%	-37%

Table 1. Primary energy consumption expressed in ktoe

The results in the table above thus show overall primary energy savings quantifiable at 37%, with savings varying by age class.

2.1.3 Scenario of generator replacement and energy upgrading

As pointed out in the Chapter "Scenario of energy upgrading of residential buildings in Trentino," the insulation intervention of the opaque envelope combined with the replacement of windows and doors allows a significant decrease in the useful energy demand of residential buildings and, consequently, a reduction in consumption, as evidenced by the data in the table below. This causes the emission terminals to be oversized relative to the new power demand and, for this reason, a lower temperature supply can be considered.

Case	V1	V2	V3	V4	V5	V6	V7	Total
Current Status	125,9	38,3	36,5	119,4	21,8	25,7	9,9	377,4
Retrained	35,4	10,3	16,8	42,5	12,0	12,9	9,9	139,6

Table 2. Heating consumption, in ktoe, of residential buildings in their current state and after envelope insulation and window replacement.

2.1.4 Detailed analysis of heat pump installations in five Trentino municipalities

Although the analysis using the BIN method allows the seasonal performance of the heat pump to be estimated with good approximation, the calculation method, based on a steady-state approach, does not allow for an assessment of the presence of thermal storage and the possibility of managing the heat pump to maximize the self-consumption of the energy produced on site. For this purpose, dynamic simulation was carried out for a selection of characteristic localities in the area, assuming a typical heat pump system. The system considered in the dynamic simulations consists of an inverter-driven air-to-water heat pump (PdC) connected to two thermal storage tanks.

Due to the sufficient homogeneity of climatic conditions in Trentino, the choice of representative municipalities is guided by a clustering process based on the climate data of Trentino municipalities, using the k-means algorithm. It was chosen to limit the number of clusters to five, each represented by the most populous municipality.

Figure 4 shows the result of clustering, highlighting the distribution on both the annual average temperature-design temperature plane and the provincial territory.

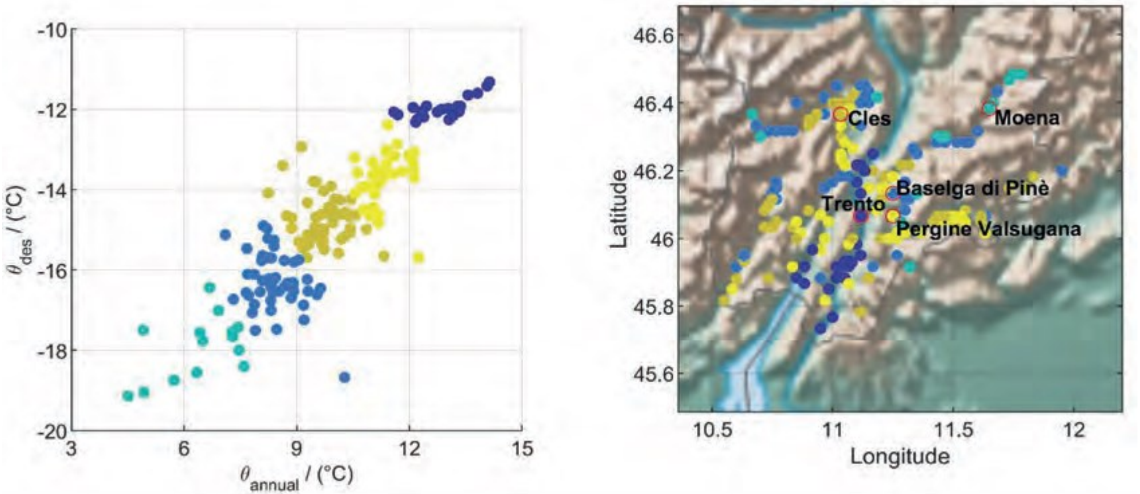


Figure 4. Result of the clustering process of Trentino municipalities. On the right are highlighted the clusters obtained in the average annual temperature-temperature plan of the project. On the left is the distribution of the clusters over the territory, with the most populous municipalities for each cluster highlighted and chosen for the simulations.

2.1.5 Results presentation and comment

The following figures show the specific electricity consumption of the four building types considered. Each graph presents consumption for each characteristic municipality and age class. As it can be seen, as the size of the building increases, specific consumption decreases as a result of the decrease in the ratio of dispersed area to heated volume, except for the large apartment building which, has a higher percentage of windowed area than the other cases. Building renovation lowers consumption to the same level regardless of the starting age class.

The graphs also highlight the fraction of self-consumed electricity. A more detailed analysis of self-consumption trends for the MF case is provided in the next section.

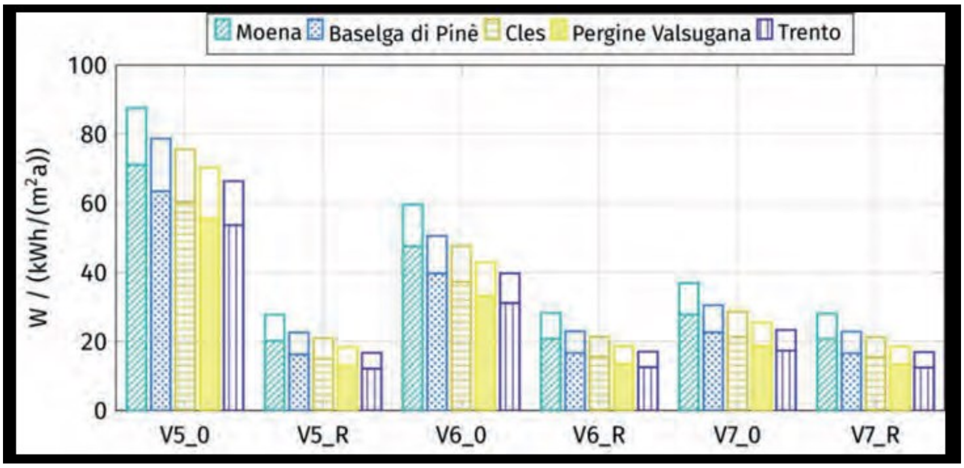


Figure 5. Specific annual electricity consumption of the single-family building (MF). The part of the bar that is not fielded indicates the share of self-consumed energy and the remainder the energy taken from the grid

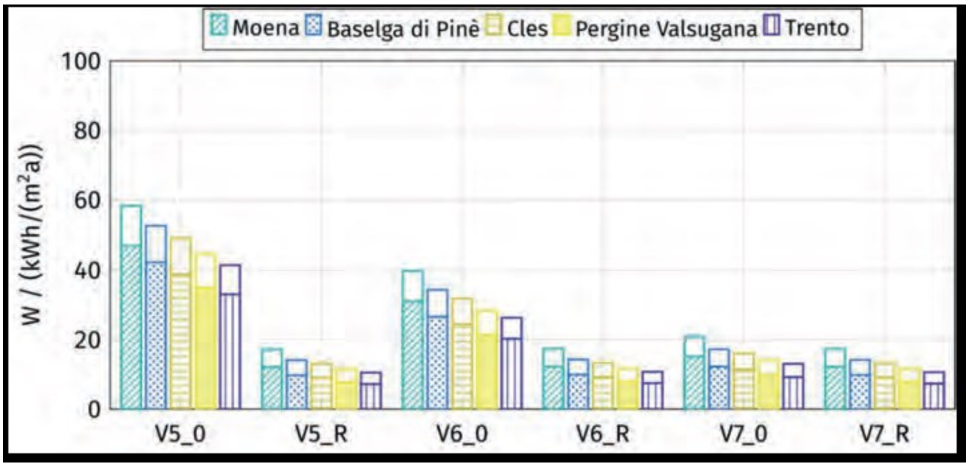


Figure 6. Specific annual electricity consumption of the townhouse building (VS). The uncambered part of the bar indicates the share of self-consumed energy and the remaining the energy taken from the grid.

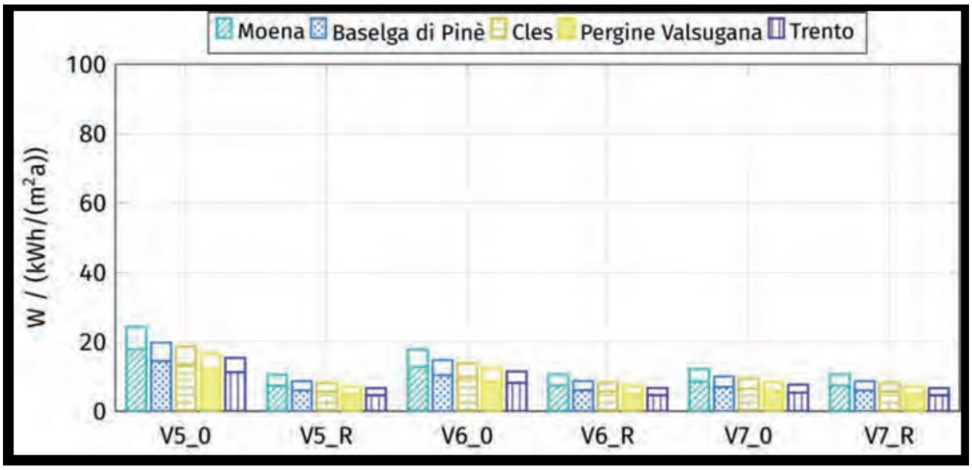


Figure 7. Specific annual electricity consumption of the average condominium building (MC). The part of the bar that is not fielded indicates the share of self-consumed energy and the remainder the energy taken from the grid.

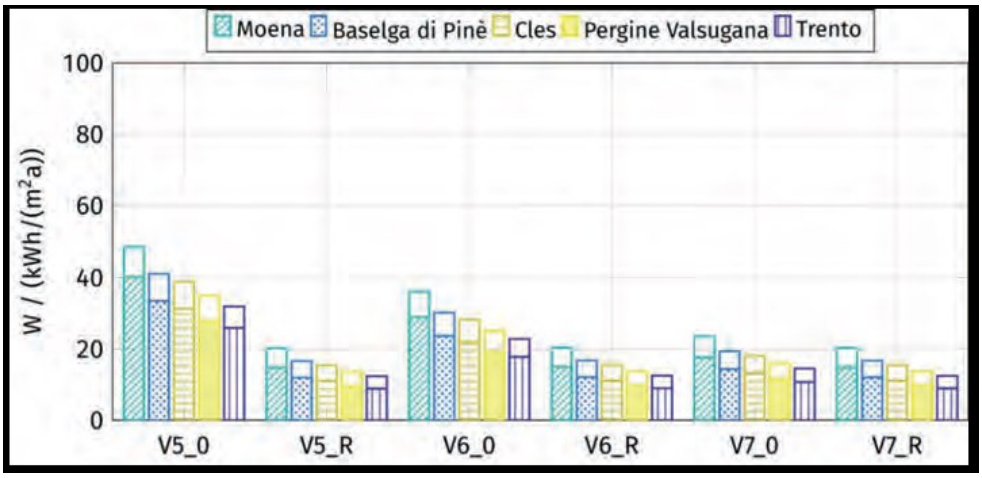


Figure 8. Annual specific electricity consumption of the large condominium building (GC). The part of the bar that is not fielded indicates the share of self-consumed energy and the remainder the energy taken from the grid.

Seasonal performance is the real discriminating factor in determining whether replacing the combustion heat generator with a PdC will result in savings in primary energy consumption. As illustrated above, the threshold value of annual SCOP is set at 2.3, so values below this do not result in benefits in terms of primary energy savings. Below are the trends of annual SCOPs for the cases analyzed (Figures 9, 10, 11 and 12).

The performance of the PdC is suboptimal for the V5_0 case for MF and VS and V6_0 for VS. The lower average annual temperature generally results in lower performance except in the MF V5_0 case, for which the trend is reversed due to the large size of the PdC resulting in frequent part-load work for locations with higher average annual temperatures. Increasing building size makes the SCOP almost independent of age class and in all cases above the threshold. In general, building renovation improves performance with higher incidence for MF and VS buildings.

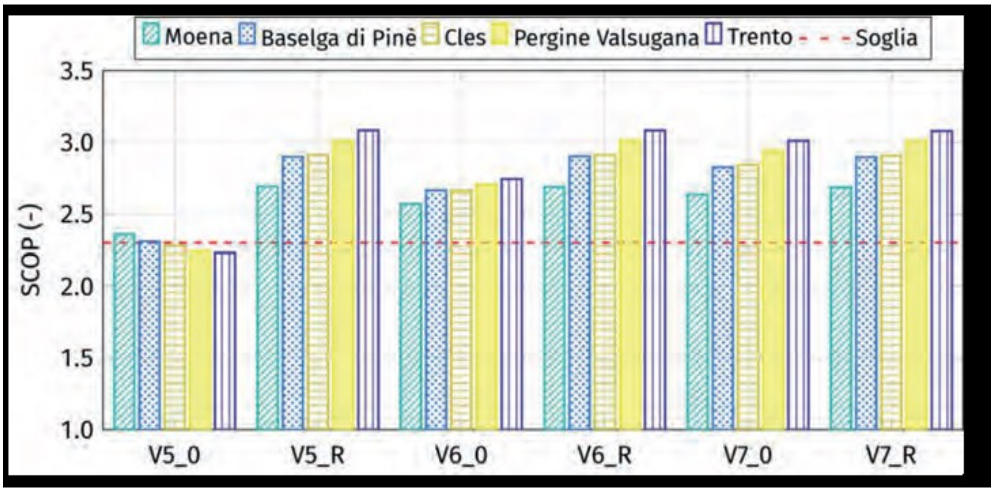


Figure 9. Seasonal COP for the single-family building (MF).

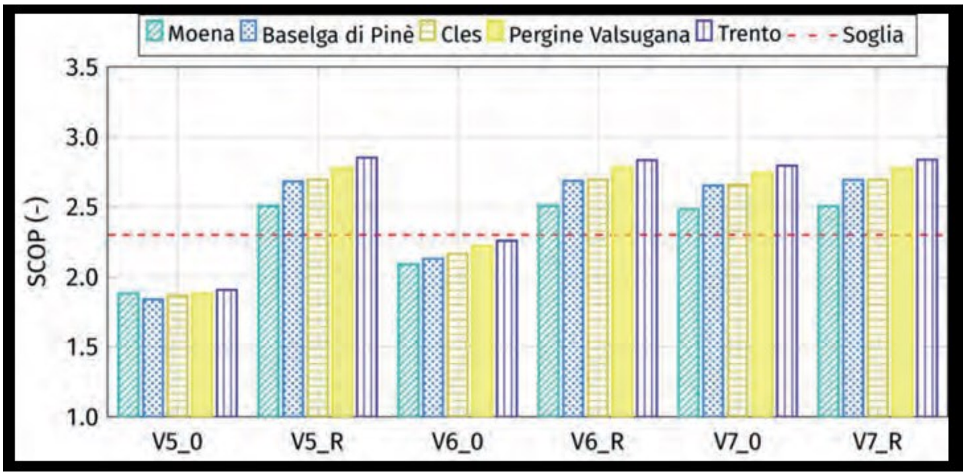


Figure 10. Seasonal COP for the townhouse building (VS).

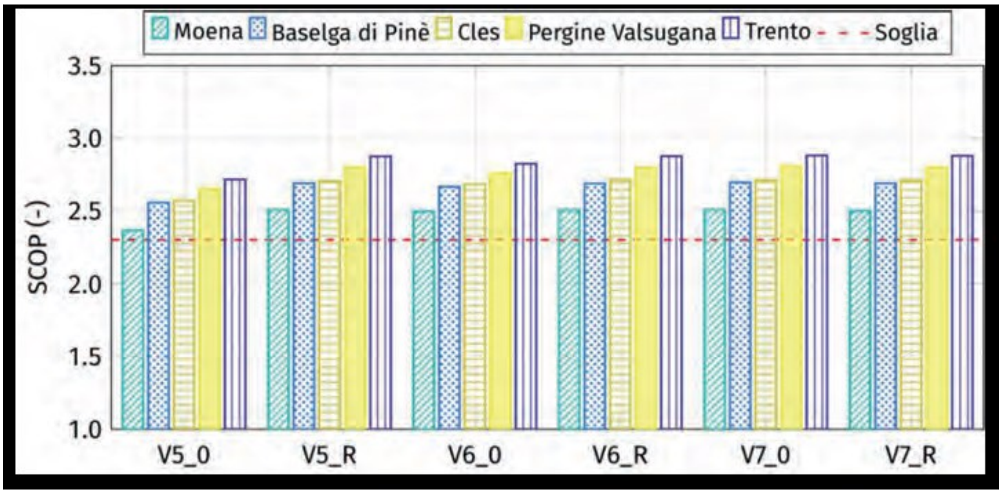


Figure 11. Seasonal COP for the average condominium building (MC).

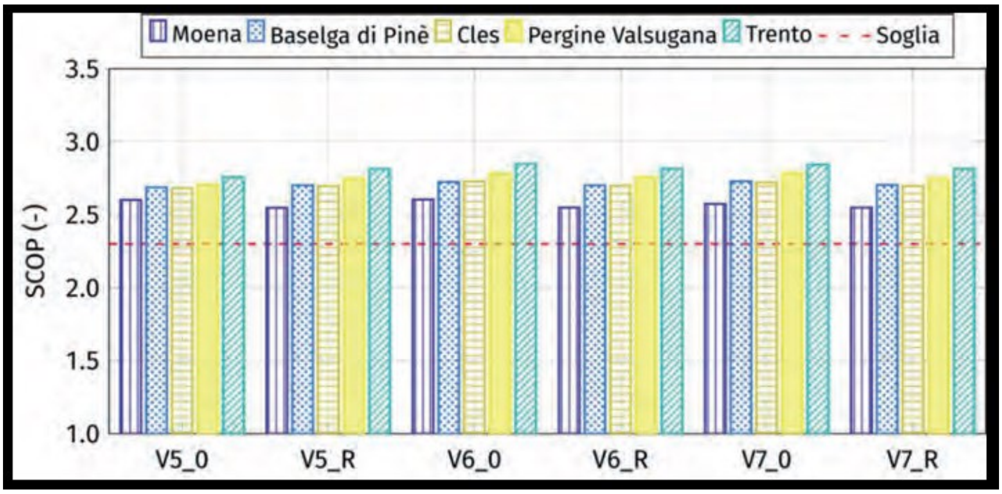


Figure 12. Seasonal COP for the large condominium building (GC).

2.1.6 Detailed analysis of heat pump systems with advanced management

Heat pump systems, depending solely on electricity, can be conveniently coupled with photovoltaic (PV) systems for on-site generation of energy from renewable sources. In the previous section, it was shown how, thanks to the photovoltaic (PV) system, part of the plant's total electricity demand can be covered by self-generation. This fraction can be increased by implementing advanced control strategies with the aim of maximizing self-consumption. This can be done by taking advantage of adjusting the power frequency of the compressor of the PdC-and thus varying the electrical power absorbed by the latter-in such a way as to take advantage of excess PV production.

Specifically, a rule-based control system was implemented in this analysis that, when certain conditions occur, intervenes by adjusting the speed of rotation of the heat pump compressor (PdC) and thus the thermal power generated. Specifically, the control is activated if the electrical power generated by the PV system exceeds the instantaneous electrical demand absorbed by the PdC and (any) auxiliary heaters. Upon the occurrence of this condition, the control increases the generated thermal power (respecting the operating constraints), and consequently the electrical absorption of the PdC so as to take advantage of all the available photovoltaic production. For this purpose, the temperature setpoints of the thermal storage tanks are raised so that excess thermal power generation can be stored. Priority was given to overheating the storage tank for domestic hot water (DHW) production being the demand for DHW present at all times of the year. Therefore, under such conditions, the setpoint of the storage tank for DHW is raised from 50°C to 60°C, and in case it is already charged, the control increases the setpoint of the storage tank intended for heating by charging it to 40°C.

Raising the setpoints results in an increase in the power consumption of the PdC and a decrease in performance, and, therefore, for control to be effective, there must be the ability to store sufficient thermal energy so as to reduce the working time of the PdC outside the hours of solar energy availability. For this reason, the storage volumes considered in the analysis were increased by 50% and 100% for DHW and heating storage, respectively.

The detailed analysis was carried out for the single-family (MF) case. Next figure shows the trend of electricity demand from the grid for all cases with and without the control to maximize self-consumption. Cases with control - dashed lines - achieve lower consumption with higher incidence for older buildings.

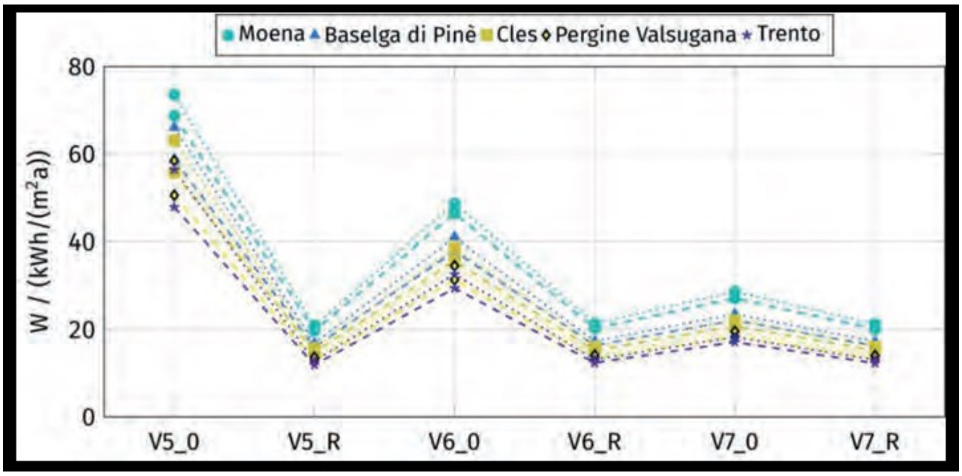


Figure 13. Electricity demand from the grid for the single-family building (MF) when advanced control is active (dashed line) and not.

The next two figures show the trends by age class and municipality of the annual "supply cover factor" (SCF) and "load cover factor" (LCF). The former is defined as the ratio of self-consumed energy to self-produced energy and provides an indication of the effective utilization of on-site power generation. The second factor represents the fraction of total demand covered by self-consumption, i.e., it is the ratio of self-consumed energy to total electricity demand.

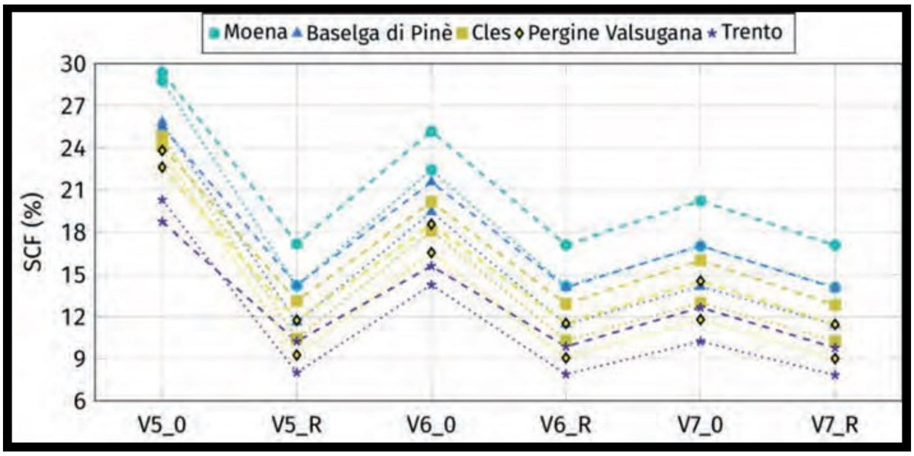


Figure 14. "Supply cover factor" (SCF) for the single-family building (MF) in case if advanced control is active (dotted line) or not

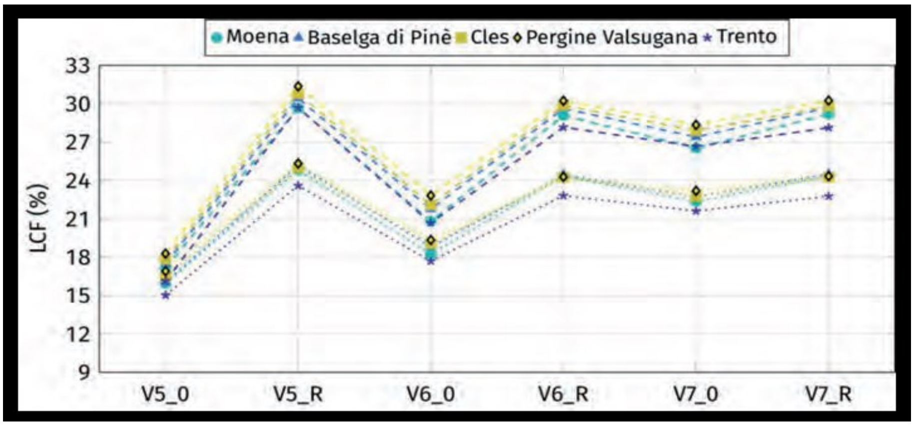


Figure 15. “Load cover factor” (LCF) for the single-family building (MF) in case if advanced control is active (dotted line) or not

The utilization of self-generated energy as expected increases as a result of control activation, however, it decreases as the quality of the envelope increases as a result of reduced energy demand while PV production remains constant. Similarly, SCF is higher in colder locations. As for LCF, the distinction is sharper as shown in Figure 21, with cases equipped with control for self-consumption increasing the coverage of total demand with self-consumed energy by 5 percent on average. Renewed cases, as a result of the reduction in total demand also presented the highest LCFs.

2.1.7 Conclusions

This chapter analyzed the potential for heat pump deployment in the provincial residential sector.
First, we investigate what is the threshold seasonal performance index for a heat pump used in the province by evaluating the SCOP of optimal heat pump sizes as the altitude of the municipality varies, in both stand-alone and centralized system configurations. This results in a value of 2.3. This was derived by considering the SCOP above which the heat pump has lower primary energy consumption than a condensing boiler with an average seasonal efficiency of 100 percent.
Next, considering only the optimal use conditions of heat pump technology, for the three age classes of provincial residential buildings (V5 1976-1990; V6 1991-2005; V7 from 2005 onward), how the replacement of the generator with an air-water heat pump is usually a solution that provides significant primary energy savings. Such replacement is all the more advantageous when energy requirements for heating are low, and therefore has better application potential when installed on upgraded properties. Simulations carried out on five representative municipalities show that the high supply temperature of the emission terminals severely limits the efficiency of the heat pump in buildings constructed between 1976 and 2005 By contrast, the combined intervention of generator replacement and simultaneous energy efficiency of the building envelope, or constructions after 2005, cases in which the temperature in the distribution system is lower, show a significant improvement in the seasonal performance index. In addition, in the case of advanced management there is an increase in the utilization of self-generated energy from photovoltaic system, although it decreases as the quality of the envelope increases as a result of the reduction in energy demand while production remains constant.

2.2 Planning natural gas distribution service extension

The purpose of this document is to map out the planning of natural gas distribution service in the Trentino region over a long-term time horizon (50 years).

It turns out to date that 66 municipalities in the Trentino territory (out of a total of 166) are not served by a natural gas distribution network system. These are especially the area of Rendena and Giudicarie Esteriori and upper Val di Non and Val di Sole, as well as other municipalities scattered throughout the territory.

This choice is made, first and foremost, in order to ensure that the provincial territory has a secure and resilient end-user energy supply system, albeit of fossil origin. .

Second, the extension prefigures the complete replacement of current sources, such as diesel, LPG and BTZ, as well as traditional domestic woody biomass systems, which are still impactful, in terms of climate- changing and polluting emissions.

In addition, network extension planning has considered possible alternative solutions to the use of natural gas in end uses, such as wood biomass district heating and heat pumps. Accordingly, taking into account the district heating systems in place, as well as the areas potentially affected such alternative solutions are subject to point analyses, either at the expense of or in relation to the planned extension of the natural gas network. The results obtained are the basis for this chapter and for Chapter 8 concerning the valorization of Trentino's woody biomass.

It is not underestimated that the application of heat pump technology for altitudes above 1000 meters above sea level is limitedly appropriate. In addition, the use of heat pumps is most effective in new buildings or buildings that have undergone deep renovations, including the distribution system.

In addition to the above, the extension of the methane gas distribution network cannot be separated from a profound and significant commitment to a profound reduction of energy consumption in the civil and industrial sectors through incisive actions to make them more efficient, both through interventions on the envelope and through the installation of new technologies for the local production of renewables and their use in self-consumption, even temporally deferred.

Lastly, the laying of technologically advanced energy networks will enable the blending of methane gas with fluids produced from local renewable sources such as green hydrogen, (addressed in this chapter), and biomethane, (covered in Chapter 9), supporting decarbonization to an ever-widening audience of end users.

Thus, in terms of the overall balance of climate-altering emissions both in the medium period of Plan 2021-2030 and in the long run to 2050, over the entire provincial territory the extension of methane gas distribution service is a viable scenario only if it is considered in conjunction with the other strategic lines, mentioned above, reduction of energy consumption and increase of energy produced from renewable sources.

On individual territories, it is pointed out that the scenario is geared toward proposing "tailor-made" solutions in relation to the environmental sustainability of energy systems, the availability of local short supply chain raw material, the technical and technological sustainability of plants-both individual and collective-as well as economic, the management conditions for operators but also for individual users, the security of the energy service offered, and the territorial vocation.

Natural gas distribution is the activity that, through an integrated system of infrastructure or network facilities, ensures the delivery to end customers of natural gas taken, primarily, from the transmission network. Ownership for the exercise of administrative functions related to natural gas distribution service lies with municipalities. In the past, in many cases, Trentino municipalities have directly entrusted the service to operators that, for the most part, corresponded to specially established municipal companies.

With the entry into force of Legislative Decree No. 164 of May 23, 2000, the liberalization of the natural gas supply chain was initiated, recomposed into a chain system of its functions (storage, regasification, transportation, distribution, and sales), each of which is carried out by different entities with autonomy and independence of role, such as to ensure in continuity the supply of gas to end users. The de facto system is regulated in terms of tariffs and service by the Regulatory Authority for Energy, Networks and Environment (ARERA). The law has thus established natural gas distribution as a public service activity that is to be entrusted, exclusively under concession, to qualified operators chosen by tender for periods not exceeding 12 years. This also resulted in municipal companies becoming more structured corporations to provide the service.

In 2011, Legislative Decree No. 93 of 2011 introduced the obligation to establish minimum territorial ambits (ATEMs) within which individual municipalities provide for the awarding of municipal concessions to a single operator, chosen through a single tender (ambit tender), which is called to operate on the entire ambit territory. For Trentino, the territorial ambit coincides, pursuant to Article 34 of Provincial Law no. 20/1212, with the entire provincial territory to which the municipality of Bagolino (BS) has also been aggregated. The calling of a single tender to entrust the service on behalf of the municipalities in the area is the responsibility of the area contracting station, a role played by the Provincial Agency for Water Resources and Energy of the Autonomous Province of Trento under Art. 34 of Provincial Law No. 20/2012 and Resolution No. 832 of May 26, 2014. Ministerial Decree No. 226 of November 12, 2011, approved the so-called "Criteria Regulation," which establishes the criteria by which to conduct the tender for the selection of the entity to be entrusted with the service for the entire scope. The contracting station also handles all relations with the operator and acts as the counterparty to the service contract by proxy of the grantor municipalities; it is assisted in the supervisory and control function by a monitoring committee consisting of representatives of the grantor municipalities belonging to the scope, with a maximum of 15 members.

2.2.1 Specific objectives and assumptions

With regard to the possibility of extending distribution service in the non-methanized municipalities, it is necessary to verify the availability of both extending the capacity of the current distribution networks and, possibly, building new natural gas transportation networks, seeking - where possible - interconnection mechanisms with the existing ones to create a safe and efficient system placed at the service of the entire provincial territory.

In light of the aforementioned functional separation of the natural gas supply chain, in terms of planning, a function must be carried out to reconcile the needs necessary for the implementation of the natural gas distribution service (to be put in place later by the new area manager) and those of the natural gas transporter. This has already been done through the contracting station's submission of comments in pub lic consultation to proposed 10-year development plans for the gas transmission network. Similar attention should be paid in terms of interlocution by the contracting station with the parties responsible for developing in decision-making processes the extensions of the transmission service (ARERA and Ministry of Economic Development - MISE).

With a view to functional coordination between transport and distribution, the goal of the Autonomous Province of Trento is to succeed in developing an interconnected gas network structure in order to ensure a secure and resilient system for the supply of natural gas to end users throughout the province. From a technical point of view, it would be preferable for this system to be held up by a system of high-pressure "feeder" pipelines possibly interconnected with each other, capable of feeding individual distribution facilities, whose networks are laid in the valley settlements serving the users. This type of interconnection is preferable to be implemented by the gas transmission network, especially in the western territory of Trentino, since it appears to be the most suitable to ensure greater benefit both within the provincial territory and outside, due to the interregional value that a backbone between the Lombardy territory and that of the Trentino valleys would assume. Also with a view to future energy supply scenarios, in line with the requirements for the achievement of European, national and provincial decarbonization goals (art. 23 of provincial law no. 19/2013), it seems reasonable that the gas transport infrastructure could also be extended to areas that are currently not methanized, to allow the implementation of feed-in points for other gases, such as biomethane (synthetic natural gas) and green hydrogen, which are considered carriers of energy produced from renewable sources.

Consequently, in a general way, the basic choice accompanying this planning cycle is to extend the service in municipalities that have shown interest in it, with regard to both those completely lacking it and those where the service is limited to a part of the inhabited areas. This is in order to bring a benefit to the end-users due to the possibility of access to more competitive sales services.

The extension will be implemented by the operator, chosen by public tender, which will be entrusted for 12 years with the distribution service for the entire provincial area as provided for in Article 39 of Provincial Law no. 20/2012; as part of this service, the operator will build the new gas distribution networks, in addition to managing the existing ones in the methanized municipalities, using its own capital whose remuneration will be ensured by the tariff system regulated by ARERA, according to principles of equalization for supra-regional macro areas. This will obviate the need to draw on resources from public budgets to be used for service extension.

2.2.2 Current gas network characteristics and analysis of criticalities

To date, there are 100 municipalities in Trentino with public natural gas distribution service through a network interconnected to the national gas pipeline system. Another 66 municipalities lack the service: a significant portion of this share is located in the western part of the province. In many cases this has happened because the necessary routes to extend natural gas transmission pipelines to support individual new distribution facilities have not been pursued. In fact, for the latter, appropriate concessionary titles for service were not issued due to a previous lack of regulatory clarity. In other cases, different choices were made for energy supply by each municipality, mainly aimed at seeking woody biomass solutions for energy supply. Likewise, the effect induced by the unavailability of public resources to help finance the construction of gas networks should not be forgotten.

According to what is reported in the documentation available to date for the purposes of the scope tender and referring to the date of 31.12.2017, a gas distribution network built in the already methanized municipalities of Trentino consists of 2,665 km of network, composed of pipes exercised in high pressure at 12 bar (3rd species), in medium pressure (4th, 5th and 6th species) and in low pressure up to 40 millibars (7th species). The redelivery points (pdr), and thus the end users, total 188,843. In the territory covered by the service, the median value of the ratio of inhabitants to pdr is 2.78 while the median value of the ratio of households to pdr is 1.19. The median value of the ratio of number of users (pdr) per km of constructed network is 40.02 [pdr/km] while the median value of the ratio of length of existing network to the number of pdr is 24.70 [m/ pdr]. The gas consumed by the end users served by the distribution network is 1'758 Smc/year (year 2017).

The territory of Trentino is also affected by 290 km of pipelines (feeder) belonging to the transportation network, of which 251 km owned by the National Methane Pipeline Company - SNAM s.p.a. (classified in the national and regional transportation network, operated with pressures in 1st and 2nd species) and 39 km owned by Retragas s.r.l. (classified in the regional network and operated in 3rd species) that feed, through delivery points organized in REMI cabins, individual plants of the gas distribution. In this way, natural gas is completely imported through the transportation networks that are developed from the lowland territories. It was not until 2021 that a point of introduction into the SNAM network of biomethane produced by anaerobic digestion at the Cadino plant, which treats the organic fraction of solid waste, was put into operation.

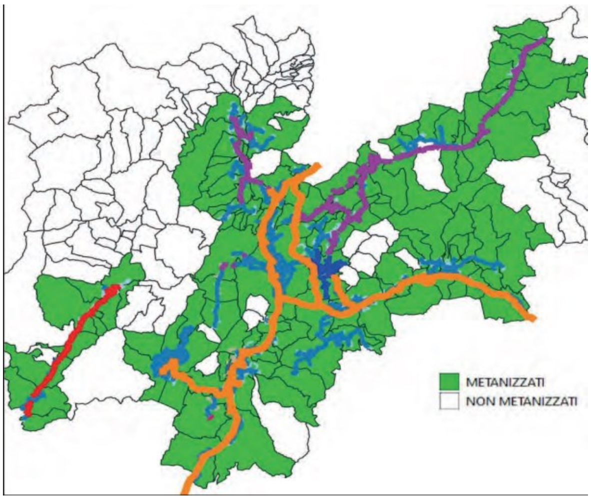


Figure 16. Municipalities with public natural gas distribution service with reference to the year 2020. (In red/orange is marked the transportation network, in magenta the distribution network exercised in 3^species

With reference to the existing network in the province, the following should be noted.

In general, these latter plants are of recent construction, presenting an estimated average life of 35 years, compared to a technical life of 60 years. The high-pressure and medium-pressure network appears to be built of steel, equipped with cathodic protection, while the low-pressure network is made of steel and only to a small extent, of plastic material. In general, this shows that the network has no need for replacement works during the term of the next scope concession.

Elements of inadequacy are presented regarding the distribution system to which the municipalities of Val di Cembra, Val di Fiemme and Fassa are subtended, supplied to date with a single REMI cabin on the SNAM network near Civezzano, where it is evident that there is insufficient availability of the flow delivered by the cabin.

It should also be pointed out that the gas distribution plants in the Alto Garda area (in the municipalities of Arco, Riva del Garda, Tenno, Dro and Torbole), a highly urbanized territory with a vocation for tourism and production, present a limit to their expansion because of the current limit to the gas withdrawal capacity from the REMI cabins located in the municipalities of Riva and Arco (13,000 Smc/h total). The gas distribution network present in these territories is de facto governed only by a regional SNAM transport pipeline, developed as an antenna with detachment from the SNAM national transport pipeline, near the town of Mori.

On the other hand, it is noted how, in the Giudicarie territory, the limits related to the transport capacity of the Retragas feeder have been exceeded, since, thanks to the construction in 2019 of the bypass of the built-up area of Pieve di Bono, the operating pressure has been raised to 12 bar. This makes it possible to extend the transport network in the Giudicarie territory, thanks to which it will be possible to feed new distribution plants to be built in the Val Rendena and Giudicarie Esteriori territories. In this way, the transmission network rising from the Brescia territory could be extended as far as Val di Sole, and then interconnect with the existing pipelines in Cles, which are fed by the SNAM network in Mezzolombardo, thus closing a first interconnection loop; in addition, the same transmission network could be extended as far as the Alto Garda area and/or towards Trento, through the territory of the Giudicarie esteriori, in a further interconnection loop.

2.2.3 Identification of the potential natural gas distribution network extension

According to the shared path to reach an understanding with the Council of Local Self-Government, already provided for in the 2013-2020 Energy Plan, regarding the extension of natural gas distribution, the development of the planning of this service has been addressed to the areas whose municipalities have expressed an active interest in the extension of the service.

With reference to municipalities without the service, the areas of western Trentino that have expressed the aforementioned interest are:

- the Rendena Valley (Porte Rendena, Pelugo, Spiazzo, Bocenago, Caderzone Terme, Carisolo, Giustino, Massimeno, Strembo, Pinzolo), where 16,090 homes and 4,827 buildings are located and about 4,500 households reside - 3,800 pdr;
- the Giudicarie Esteriori (Bleggio Superiore, Comano Terme, San Lorenzo Dorsino, Stenico, Fiavé), where 6880 dwellings and 3434 buildings are located and about 3,470 households reside - 2,700 pdr;
- the Val di Sole (Caldes, Cavizzana, Commezzadura, Croviana, Dimaro Folgarida, Malé, Mezzana, Ossana, Peio, Pellizzano, Rabbi, Terzolas, Vermiglio), where 17607 dwellings, 6028 buildings are located and about 6'560 households reside - 4,800 pdr;
- the third bank of Non Valley (Cis, Livo, Bresimo, Novella), where 3064 dwellings and 1919 buildings are located and about 2,000 households reside – 1,500 pdr.

The same interest was expressed by the municipalities of Cimone and Garniga in the Adige Valley territory (about 490 households - 410 pdr), by the municipalities of Canazei and Cavalese (for the hamlet of Masi) in the Fiemme and Fassa territories for about 1'100 households - 850 pdr, by the municipalities of Ronchi Valsugana and S. Orsola Terme in Valsugana for about 660 households - 550 pdr, as well as from the municipalities of Molveno (about 520 households - 440 pdr) , Castel Condino (about 120 households - 100 pdr), Drena (about 260 households - 220 pdr) , Sfruz (about 160 households - 130 pdr).

In addition, some municipalities, for which a service is in place for the distribution and sale of different gases through LPG-fueled island networks, have expressed the need for interconnection to the natural gas network system to access sales services: this is the case of the municipalities of Ronzo Chienis (400 existing LPG users) and Ton (forecast of 450 pdr compared to the current 330 existing LPG users) where the current concessions are soon to expire, at the end of the year 2021 and the year 2027, respectively.

The Municipality of Molveno has asked for an assessment of whether the distribution service, developed today in the form of private administration of natural gas regasified on site and distributed through a private network, could be upgraded to a public gas distribution service, including through interconnection to the gas network system. A similar technical assessment should be made for the municipality of Comano Terme where, however, there is an existing concession to supply regasified natural gas on site in the settlements of Ponte Arche and Cares.

The number of potential pdr indicated above was estimated, territory by territory, on the basis of a user connection density, declined with respect to the number of resident households, considered likely to be the one currently present in similar territories already equipped with the service. The estimate takes into account the similarity of social, economic and orographic characteristics of the valley territories. As such, the parametric values of potential PDRs used in the analysis on territories aggregated by valley are represented in the table below.

Non methanized zone	Already methanized zone for comparison	Residents/pdr	Resident Families/pdr	pdr/house	pdr/tot buildings
Val di Sole	Val Fiemme-Fassa	3.26	1.37	0.37	1.11
Val di Non (3^sponda)	Val di Non	3.07	1.29	0.65	0.98
Val Rendena	Atem Trento	2.78	1.19	0.65	1.12
Giudicarie Est.	Val di Non	3.07	1.29	0.65	0.98

Table 3. Indexes

The choice of making the pdr explicit in terms of residential users seems to be the most realistic one in the case of gas distribution service, since the main propensity to access the service is the population residing there.

However, the desirability of the service to the numerous owners of second homes in territories with a strong tourist vocation, where the presence of housing (first and second homes) is substantial, should not be forgotten. Should one wish to consider the incidence of second homes, it is possible to estimate a greater number of potential pdr in the various territories. Therefore, the above table shows both the ratio of active pdr to total buildings (both residential and nonresidential) and the ratio of the number of active pdr to the number of dwellings (both residential and nonresidential) based on 2011 censuses (ISPAT data); the representativeness of the index referring to buildings and dwellings was considered by means of the 60 percentile at 60 percent.

With reference to municipalities in which public distribution service is already in place (so-called methanized municipalities), the possibility of extending the gas network to serve new users is mainly aimed at population centers secondary to the municipality's main built-up area. In such municipalities, it is noted that there is the possibility of making extensions prior to the scope tender as work in progress (LIC) by existing operators. Network extensions that will not be met by existing operators can be evaluated in the framework tender.

While planning evaluations, similar reasoning is made for the town of Bagolino (799 bpdr), in the municipality of the same name in the province of Brescia, which has expressed interest in natural gas supply through conversion of the existing propane air-fired distribution plant.

In planning terms, it is likely to estimate that the possibility of extending the gas network to serve new end users, both in non-methanized and methanized municipalities in Trentino, will affect a total heat demand of 233 GWh, of which 175 GWh will be substituted for diesel fuel and 58 GWh for LPG. Potential new consumption and new users, broken down in each category of municipalities that have expressed an interest in extending the service, are shown in Table 28, which shows the characteristics of the gas network extension scenarios, according to indications preliminarily estimated by APRIE because of the requests received from municipalities.

Tipology	PDR		Heat demand (TWh)			New grid (km)
	Potentials	Foreseen	Diesel oil	GPL	TOT	TOT
Methanized municipalities	5.927	3.220	0,036	0,025	0,061	213
Non-methanized municipalities	16.698	8.107	0,140	0,032	0,172	459
TOT	**22.625**	**11.327**	**0,175**	**0,058**	**0,233**	**672**

Table 4. Gas grid extension scenarios

The results of the forecasts about the possibility of building new gas distribution networks in non-methanized municipalities, to be declined under the forecasts of the Tender for the assignment of service in the single provincial scope, will be defined in a specific understanding between the Province, as the Contracting Authority, and the Council of Local Self-Government.

2.2.4 Method and analysis carried out for distribution service planning purposes

To analyze the planning potentials of natural gas distribution network expansion, to assess the feasibility of extending natural gas distribution service in the aforementioned territories, three pillars were evaluated:

1. the compatibility analysis of the potential natural gas consumption and number of users potentially affected by the service, with the decarbonization goals, at 2030 and 2050, according to the current Provincial Law No. 17/2013;

2. the analysis of the potential end-users that can be served with the upgrading of existing biomass district heating networks, setting the objective of prioritizing the service dispensed by these networks over implementing solutions that involve the construction of new networks for the supply of natural gas, this also for the purpose of complying with the indications of Article 9, paragraph 3 of Ministerial Decree No. 226/2011;

3. the analysis of the technical-economic feasibility conditions for the extension of the distribution service, taking into account the rules dictated by ARERA for the eligibility of investments for the construction and operation of new networks for both gas distribution and transportation. The analysis takes into account the proposed development of the natural gas transportation network in the western territory of Trentino, indicated in the Ten-Year Development Plans of the transportation network, although their approval has not yet taken place.

2.2.5 The first pillar: compatibility scenarios between potential expansion of the natural gas distribution network and provincial decarbonization goals

In this chapter, the first pillar is the most extensively addressed. What has been analyzed by FBK is presented in terms of the expectation of the change in Trentino's energy supply mix toward the end of the 2021-2030 decade of responsibility, including substantially, with the extension of natural gas service, consistent with the 2030 and 2050 climate-altering emissions reduction targets. This analysis is therefore the knowledge base needed to define the planning and climate mitigation terms of the extension of the natural gas network, with the potential expansion of consumption and the number of users. It, in fact, considered, albeit with different timeframes, the prevailing hypothesis of natural gas penetration within the Trentino territory in the currently non-methanized areas; this choice has at its basis a close integration with the current use and further valorization of Trentino's woody biomass (in Chapter 8) in district heating (TLR) plants instead of new gas distribution networks. Possible new utilities to be connected to the new gas distribution network were considered in the roster. In addition, the potential for biogas production and refining to CH_4 (in Chapter 9) is considered, as well as verifications of potential exploitation of hydrogen in blending with methane gas in order to decarbonize the same fuel.

These scenarios were developed through modeling analysis with the EnergyPLAN tool.

For the purpose of assessing the compatibility between potential expansion of the natural gas distribution network and decarbonization goals, scenarios having the following basic assumptions are considered:

- the dynamic-integrated-optimized scenarios and the overall decarbonization targets presented in Chapter 2, Section 2, Part 2. Specifically, the so-called LC+ scenario is considered, i.e., corresponding to the targets to date in Provincial Law No. 19/2013;

- energy valorization of woody biomass in those areas where district heating plants are already present, saturating the production capacity of the plants and completing the extension of district heating networks;

- elimination, where natural gas will be available, of heating oil products such as diesel and LPG;

- congruent use of winter and summer air conditioning technologies such as heat pumps;

- the possibility of extending the Baseline 2016 natural gas network with potential new users and potential new consumption in both already methanized and non-methanized areas;

- the possibility of producing hydrogen from electrolysis in Trentino territory, integrating it into the gas network and meeting part of the provincial heat demand, as an alternative mode to heat pumps, thanks to the direct decarbonization of methane.

Scenarios of hydrogen integration into the gas grid were evaluated according to two trajectories:

H2 trajectory:

i. extension of the gas grid with new methanized utilities replacing heat pumps;

ii. role of hydrogen in maintaining decarbonization targets.

H2+ trajectory:

i. extension of gas network with new methanized utilities replacing heat pumps;

ii. further methanization of 8-15% of provincial heat demand covered by heat pumps;

iii. role of hydrogen in maintaining decarbonization targets.

The following table traces the methodological steps and results obtained, which are summarized as follows.

First, a reduction in heat demand covered by heat pumps was estimated, in the H2 trajectory against the extension of the gas grid, in the H2+ trajectory adding a further reduction with a percentage between -8 and -15%.

The heat demand "subtracted" from heat pumps was then allocated to gas boilers. This, as a direct effect, results in EnergyPLAN increasing CO2 emissions and failing to meet decarbonization targets at 2030 and 2050.

Therefore, in view of the above, the composition of heat demand covered by gas boilers had to be revised as a mix between heat demand covered by natural gas and hydrogen blending. Using the EnergyPLAN model, the exact mix was evaluated, with the necessary minimum amount of heat demand covered by hydrogen.

In the next methodological step, the heat demand covered by the three technologies under consideration--heat pumps, natural gas contributing boilers, and hydrogen contributing gas boilers--was verified to remain the same even downstream of transitions from one technology to another.

For the production of the hydrogen required for blending into the gas grid, the size of daily storage was, first, calculated by dividing the heat demand covered by hydrogen by 366.

Among the outputs of the EnergyPLAN analysis, the power needed for the electrolyzers was calculated, according to the assumption of production entirely in the Trentino area, the natural gas requirements and the hydrogen requirements.

By calculating the total gas demand as the sum of natural gas and hydrogen and dividing it by the average unit demand of a redelivery point (PDR), the number of PDRs subject to the gas grid was calculated. At the same time, by calculating the ratio of hydrogen demand to total gas demand, the volume % of hydrogen to be blended into the gas network was calculated.

Metodologia		Parametri	2016	2030				2050			
			BASE	REF	LC+	LC+_H2	LC+_H2+	REF	LC+	LC+_H2	LC+_H2+
[1]	Reduction PdC for extension gas grid (and for -8/-15% PdC)	PdC Heat (TWh)	0.283	0.282	1.862	1.638	1.474	0.269	3.997	3.797	3.493
[2]	Increase gas and partial sub. with H2 (Ener- gyPLAN)	Boil Gas Heat (TWh)	3.434	3.427	2.181	2.173	2.063	3.269	0.147	0.138	0.104
[3]	Increase gas and partial sub. with H2 (Ener- gyPLAN)	Boil H2 Heat (TWh)	0.00	0.00	0.00	0.241	0.516	0.00	0.00	0.207	0.545
[4]	Total verification PdC+B_ Gas+B_H2 Heat	PdC+B_ Gas+B_H2 Heat (TWh)	3.717	3.709	4.043	4.052	4.052	3.538	4.144	4.143	4.143
[5]	Calculation daily storage	H2 storage (H2) (GWh)	0.00	0.00	0.00	0.660	1.409	0.00	0.00	0.566	1.490
[6]	Power required from electrolyzers (EnergyPLAN)	H2 electrolyser (MW)	0	0	0	142	303	0	0	115	303
[7]	Gas demand (EnergyPLAN)	TOT Gas (TWh)	6.66	6.30	5.17	5.15	5.01	5.84	1.36	1.35	1.32
[8]	H2 demand (EnergyPLAN)	TOT H2 (TWh)	0.0	0.0	0.0	0.25	0.53	0.0	0.0	0.21	0.56
[9]	Gas and H2 demand	TOT Gas+H2 (TWh)	6.66	6.30	5.17	5.40	5.54	5.84	1.36	1.56	1.88
[10]	Calculation PDR (Average value per unit)	PDR (x 1000)	395	374	318	332	341	363	93	107	129
[11]	Calculation % in volume of H2	% H2	0.00	0.00	0.00	**4.63**	**9.57**	0.00	0.00	**13.46**	**29.79**

Table 5. Hydrogen integration scenarios in the gas grid: methodology and results.

Based on today's knowledge, referring to the entire energy infrastructure chain, from transportation to end uses, the permissible limits of the amount of hydrogen blended with natural gas to pure hydrogen differ depending on the infrastructure component considered, as do the technologies and standards. Based on an extensive review of the literature, to which reference is made for further discussion, from which MARCOGAZ (2018), Figure 2, is cited here, low blending is considered to be ≤10 percent by volume, where no major infrastructure changes are expected, and high blending is considered to be between 10 and 30 percent by volume, where major infrastructure changes are expected, as per the literature.

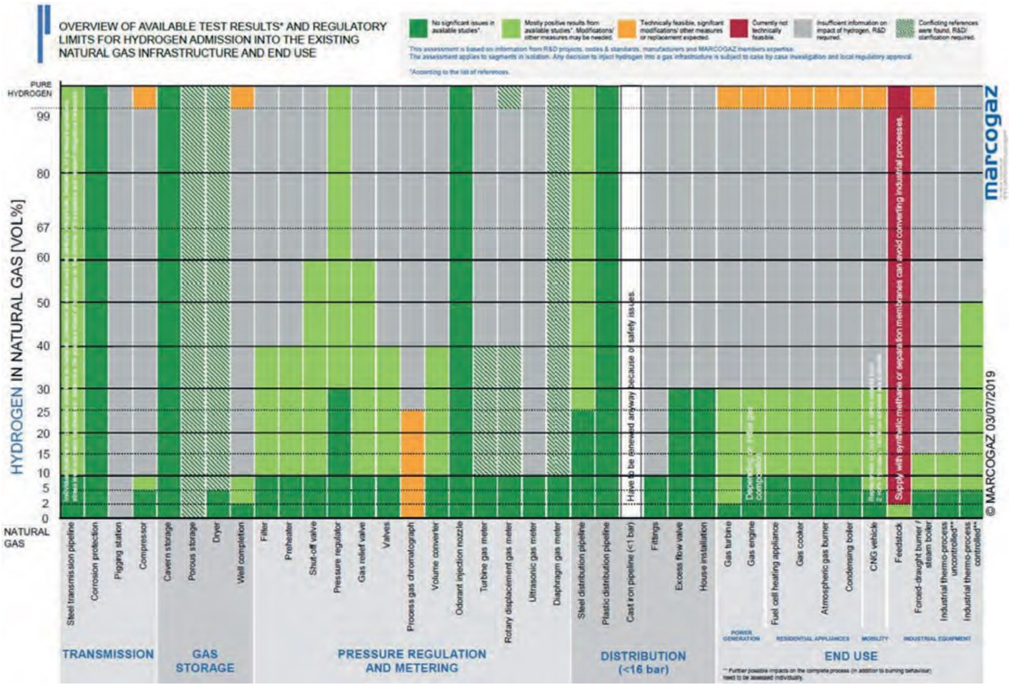


Figure 17. Hydrogen injection compatibility overview of the various components of the natural gas supply chain, from transportation and distribution to end use.

In overall terms, it can be said that in both modeled trajectories at 2030, there is a low percentage of hydrogen by blending, while at 2050 there is a medium percentage.

In the process of decarbonization (at 2030 and 2050), the H2 and H2+ trajectories, by hydrogen blending, thus allow more utilities (pdr) connected to the gas grid than natural gas alone.

2.2.6 Heat demand

The following table shows the heat demand of H2 and H2+ trajectories, characterized by the introduction of hydrogen present in blending form into the gas network. The following observations emerge:

- In the H2 trajectory, at 2030 and 2050, hydrogen covers 3% of the heat demand in LC+.
- In the H2+ trajectory, at 2030 hydrogen covers 7% in LC+. At 2050, hydrogen covers 9% in LC+.

TWh/year	2016	2030				2050			
	BASELINE	REF	LC+	LC+_H2	LC+_H2+	REF	LC+	LC+_H2	LC+_H2+
Energy efficiency building envelope	0,94	1,04	1,31	1,31	1,31	1,14	1,70	1,70	1,70
Heat Demand	7,24	7,22	6,97	6,98	6,89	6,22	6,22	6,22	6,22
Solar thermal	0,15	0,15	0,24	0,24	0,24	0,14	0,36	0,36	0,36
Heat pump	0,28	0,28	1,86	1,64	1,47	0,27	4,00	3,80	3,49
Biogas th	0,02	0,02	0,04	0,04	0,04	0,02	0,04	0,04	0,04
CHP/Indiv gas th	1,09	1,09	1,25	1,25	1,25	1,04	0,47	0,47	0,47
Boiler/Indiv diesel oil	0,68	0,68	0,03	0,03	0,03	0,65	0,00	0,00	0,00
Boiler/Indiv GPL	0,18	0,17	0,01	0,01	0,01	0,17	0,00	0,00	0,00
Boiler/Indiv gas	3,43	3,43	2,18	2,17	2,06	3,27	0,15	0,14	0,10
Boiler/Indiv H2	0,00	0,00	0,00	0,24	0,52	0,00	0,00	0,21	0,55
Boiler/Indiv biomass	1,17	1,17	1,13	1,13	1,13	1,12	1,01	1,01	1,01
CHP/DH biomass th	0,07	0,07	0,07	0,07	0,07	0,07	0,06	0,06	0,06
CHP/DH gas th	0,10	0,10	0,10	0,10	0,10	0,10	0,09	0,09	0,09
Boiler/DH biomass	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02	0,02
Boiler/DH gas	0,04	0,04	0,04	0,04	0,04	0,04	0,03	0,03	0,03
Boiler/DH diesel oil	0,004	0,004	0,004	0,004	0,004	0,003	0,003	0,003	0,003

Table 6. Scenarios of hydrogen integration into the PAT gas grid: heat requirements

2.2.7 Hydrogen demand

Table 5 shows the total hydrogen requirements for the thermal and transportation sectors of the H2 and H2+ trajectories. Hydrogen mobility, absent in the 2016 Baseline, is projected on an experimental basis to 2030, in small "captive fleets," at 0.6 percent in LC+ of transportation energy needs, and then find a large market by 2050 and reach a major share at 27 percent in LC+ of transportation energy needs. By 2030, in the H2 and H2+ trajectories, the hydrogen demand for the thermal sector is thus predominant, with a maximum of 0.52 TWh/year in LC+_H2+ (in the same scenario, the hydrogen demand for the transport sector is 0.02 TWh/year). At 2050, in the H2 and H2+ trajectories, the hydrogen requirements for thermal and transport are both significant, with transport requirements prevailing in H2 and thermal requirements prevailing in H2+.

TWh/year	2016	2030				2050			
	BASELINE	REF	LC+	LC+_H2	LC+_H2+	REF	LC+	LC+_H2	LC+_H2+
Boiler/Indiv H2	0.00	0.00	0.00	0.24	0.52	0.00	0.00	0.21	0.55
Transport H2	0.00	0.00	0.02	0.02	0.02	0.00	0.45	0.45	0.45
TOTAL H2	0.00	0.00	0.02	0.26	0.54	0.00	0.45	0.66	1.00

Table 7. Total hydrogen demand by thermal sector and by transport sector.

2.3 Methanization of the western areas of Trentino

To date, an important part of the western part of the province still lacks the public natural gas distribution service implemented through a network interconnected to the national gas pipeline system. Other municipalities, especially in the eastern part, lack the service due to having made different choices for energy supply or due to the impossibility (given by legislation) of entrusting the service to a qualified operator.

Generally speaking, the basic choice that accompanies this planning cycle is to trace the planning of natural gas distribution service in the Trentino territory over a long-term time horizon (50 years). This choice is made, first and foremost, in order to ensure a secure and resilient system for the supply of energy source, albeit of fossil origin, for the benefit of end users throughout the provincial territory. In fact, the extension of gas-to-gas service should be framed as an opportunity to increase public services organized for users in the valleys of the territory and will give users the opportunity to access a more competitive sales service market for energy supply. Second, the extension foreshadows the complete replacement of current sources, such as diesel, LPG and BTZ, which are still impactful, in terms of climate-changing and polluting emissions. In addition, the extension of the methane gas distribution network does not exclude a commitment to a drastic reduction of energy consumption in the civil and industrial sectors through incisive actions to make them more efficient.

Lastly, the laying of technologically advanced energy networks will enable the blending of methane gas with fluids produced from renewable sources such as green hydrogen and biomethane, supporting decarbonization towards an increasingly wide range of end users.

The extension will be implemented by the operator, chosen by public tender, which will be entrusted with the distribution service for the entire provincial area, with a duration of 12 years, as provided for by Art. 39 of Provincial Law no. 20/2012, which will build the new gas distribution networks, in addition to managing the existing ones in the methanized municipalities, employing its own capital whose remuneration will be ensured by the national tariff system.

The areas in western Trentino that have expressed an interest in extending gas distribution service are:

- Val Rendena (Porte Rendena, Pelugo, Spiazzo, Bocenago, Caderzone Terme, Carisolo, Giustino, Massimeno, Strembo, Pinzolo), for a total of about 3800 potential pdr;

- Giudicarie Esteriori (Bleggio Superiore, Comano Terme, San Lorenzo Dorsino, Stenico, Fiavé), for a total of about 2,600 potential pdr; and

- Val di Sole (Caldes, Cavizzana, Commezzadura, Croviana, Dimaro Folgarida, Malé, Mezzana, Ossana, Peio, Pellizzano, Rabbi, Terzolas, Vermiglio), for about 4800 potential pdr;

- the third bank of Val di Non (Cis, Livo, Bresimo, Novella), for about 1500 potential pdr.

The same interest has been expressed by the municipalities of Molveno, Castel Condino, Canazei, Cavalese (hamlet of Masi), Cimone, Garniga, Drena, Ronchi Valsugana, S. Orsola Terme, and Sfruz, involving about another 2,800 redelivery points (pdr). In addition, some municipalities, for which a service is in place for the distribution and sale of gas through island networks powered by LNG or LPG, have expressed the need for interconnection to the natural gas network system.

In order to assess the feasibility of extending natural gas distribution service to these realities, three essential aspects were evaluated:

1. the compatibility analysis of the potential natural gas consumption and number of users potentially affected by the service, with the decarbonization goals, at 2030 and 2050, according to the current provincial law No. 17/2013;
2. the analysis of the potential end-users that can be served with the upgrading of existing biomass district heating networks, setting the objective of prioritizing the service dispensed by these networks over implementing solutions that involve the construction of new networks for the supply of natural gas, this also for the purpose of complying with the indications of Article 9, paragraph 3 of Ministerial Decree No. 226/2011;
3. the analysis of the technical-economic feasibility conditions for the extension of the distribution service, taking into account the rules dictated by ARERA for the eligibility of investments for the construction and operation of new networks for both gas distribution and transportation. The analysis takes into account the proposed development of the natural gas transportation network in the western territory of Trentino, indicated in the Ten-Year Development Plans of the transportation network, although their approval has not yet taken place.

For the first aspect, in this more extensively presented Plan, the extent to which the energy supply mix of Trentino is expected to be changed toward the end of the 2021-2030 ten-year period, including substantially, with the expansion of natural gas service, so as to meet the 2030 and 2050 climate-changing emission reduction targets, has been analyzed. This analysis is therefore the knowledge base needed to define the planning and climate mitigation terms of the extension of the natural gas network. It in fact considered, albeit with different timelines, the prevailing hypothesis of natural gas penetration within the Trentino territory in the currently non-methanized areas; this choice has at its basis a close integration with the use of woody biomass.

The energy analysis shows how the extension of gas distribution service is feasible, while achieving, at the same time, the reductions in climate-altering emissions projected to 2030 based on four assumptions:

1. energy valorization of woody biomass in those territories where district heating plants are already present and where effective the use of this renewable source for energy production

due to territorial peculiarities, saturating the production capacity of the plants and completing the thickening of the district heating network, possibly revamping the plants and expanding the network to new areas;

2. elimination, where natural gas will be available, of heating oil products such as diesel and LPG;

3. congruent use of winter and summer air conditioning technologies such as heat pumps because of the results of the specific scenario, mentioned in 1;

4. the estimated gas utilities (PDR) parameterized according to the actual degree of penetration of the gas distribution network and consequently the level of activation of new natural gas utilities.

The results of the energy analysis confirm the goodness of increasing natural gas-fired utilities connected to the planned extension of the natural gas network to the affected areas of western Trentino provided that the natural gas distributed throughout Trentino is blended with a percentage of hydrogen between 4 percent and 5 percent in the distribution network; this is to maintain the achievement of the 2030 climate-altering emissions reduction targets. Scientific evidence and ongoing experiments show that, for these blending percentages, the technical characteristics of the network are already adequate, as are the end users' plant terminals.

For the second aspect, within the studies carried out about the compatibility of extending the service in non-methanized municipalities, due consideration was given to the presence of district heating networks (existing,planned or potential). The verification reports of possible coexistence or prevalence between district heating network, in particular wood biomass, and methane gas distribution network, have taken their cue in the analysis on the territory from the energy performance, economic-financial and mode of operation current power plants and district heating networks and their potential optimization and expandability both in terms of saturation of the existing district heating network and in terms of expansion of the network, including with revamping of the boiler, in order to increase the number of users connected. In fact, also in order to comply with the indications of Article 9, paragraph 3 of Ministerial Decree No. 226/2011, which provides, in fact, the impossibility of overlapping energy infrastructures, at the time of structuring the hypothesis of the network scheme for gas distribution service, the possible utilities that can be supplied with district heating were excluded from the list of the gas network. These assessments were carried out in coordination with the municipalities. For the third aspect, based on the degree of distribution service extension in the provincial territory, the feasibility aspects of distribution network development and those of transport network development appear to be interrelated, especially with reference to the western part of the territory.

The Contracting Station, considering the feasibility of the interventions proposed by the municipalities, carried out evaluations looking for the conditions for the sustainability of a public service spread homogeneously in a territory. The Contracting Station conducted the evaluations by drafting cost benefit analyses (CBAs) according to the Guidelines provided by the aforementioned Resolution 570/2019/R/GAS, which implements the document approved by Resolution 410/2019/R/GAS. The assumptions adopted were as follows:

- The utilities that can be served by biomass district heating networks were excluded

- The required extension interventions were structured in the stand-alone logic, expressly requested in ARERA Resolution 570/2019/R/GAS implementing the document approved by Resolution 410/2019/R/GAS: the scope of analysis with which each intervention was verified coincided for individual municipalities to the municipal territory, while an aggregate system was developed for municipalities in the valleys completely lacking the service (valley methanization).

- Simulations of industrial feasibility plans were developed considering development of backbone pipelines suitable for feeding individual distribution facilities in the settlements, considering the proposed developments of the regional transmission network indicated in the 10-year development plans, rather than implementation hypotheses implemented directly by a possible industrially well-organized distributor;

- Evaluations of proposed interventions in municipalities in climate zone E were conducted by drawing up specific cost-benefit analyses, both user and operator side, according to the Guidelines set forth in the aforementioned Resolution 570/2019/R/GAS, which incorporates the document approved by Resolution 410/2019/R/GAS;

- The interventions proposed by mountain municipalities in climate zone F (most of the territories), in light of the provisions of Article 23, paragraph 4 bis of Legislative Decree No. 164/20001, were structured by analyzing the sustainability of the costs on the operator side, simulating a business plan marked by adequate financial ratios compared to the threshold of anomaly referred to in Ministerial Decree No. 226/2011 and implemented according to a timetable for the execution of interventions characterized by a major organizational and productive commitment especially with reference to the valleys.

The simulations conducted show that the interventions for the construction of the new distribution network in the western territories, to be indicated in the tender ensuring the economic and financial balance by the operator, remain conditioned by the level of penetration, and the related timing, of the gas transportation backbones in the valley territories proposed in the 10-year gas transportation plans. Depending on whether the said backbones are developed in a timeframe congruent with the timelines envisaged by the term of the next scope concession, or whether simple extensions of the existing pipes belonging to the distribution network are assumed, very different effects originate, for the feasibility of constructing distribution networks in individual settlements. In general ways, the analyses carried out show that:

- In all cases considered, new methanization interventions are characterized by the benchmark (m/pdr) above the threshold of 25;
- Most of the extension and new methanization interventions fall in mountainous municipalities in climate zone F and were considered efficient and evaluated positively for consumers;
- In non-methanized municipalities considered individually and in the valley aggregates (valley methanization) there are positive indices for sustainability on the operator side provided that the distribution service is extended to the entire cluster of planned users and there are the conditions to be able to build most of the distribution networks in the first half of the period of the scope concession; these interventions are configured as extensions whose cost is considered eligible by ARERA.
- With regard to methanized municipalities, some of the requested extensions fall under the Minimum Development Conditions and are therefore mandatory, others fall under optional interventions and remuneration will be provided by the tariff system. However, it notes that some interventions, falling in municipalities in climate zone E, are not positive in terms of user-side cost-benefit analysis, and therefore will not be able to be included in tariffs by ARERA.

The lines of analysis highlighted above confirm the possibility of extending distribution service to municipalities that have requested it with some exceptions exemplified in the dedicated chapter, in which the specific details are inferred.

2.3.1 Green hydrogen in Trentino to 2030

I Trentino proposes to elaborate its own roadmap in regards to green hydrogen, in compliance with a European and national framework but with a specific provincial declination and actions with a high degree of flexibility, in order to contribute to climate neutrality at 2050.

Due to the time goal of this Provincial Environmental Energy Plan, 2021-2030, the ongoing experiments in Italy and Europe and the related economic magnitudes at stake, as well as the scientific evidence, the decarbonization of natural gas for the grid and the transport sector, mainly heavy and captive fleets, and the industry sector are considered as the driving element for the contextualization of green hydrogen end uses in Trentino at 2030.

The scenario, as well as the various options, require, downstream of the Provincial Environmental Energy Plan, in-depth energy-environmental studies aimed at analyzing the operation as a whole in terms of the balance of climate-altering emissions and with a view to a more effective energy valorization of Trentino's renewable sources, as well as economic evaluations. In this regard, coordinated territorial actions are promoted in research and innovation projects with a direct impact on the provincial territory, even in the short to medium term, as well as to stimulate private investment, among other things, through existing EU financial institutions, funds and instruments, such as the European Investment Bank, the Sustainable Europe Investment Plan, the Innovation Fund, the European Structural and Investment Funds and the Connecting Europe Facility, as well as through the design of innovative instruments.

Cod.	Action Title	Description	Actors Involved	Typology of Action
H1	Hydrogen coordination table	Establishment of a coordination table aimed at proposing projects under European and national programs and funds in implementation of the Trentino hydrogen road map	Autonomous Province of Trento; Local research institutes.	Programmatic
H2	Roadmap thirty	Carry out a technical, economic and environmental feasibility study on the potential of hydrogen in Trentino, evaluating different approvision and/or production scenarios, to define a Trentino road map	Autonomous Province of Trento	Programmatic
H3	Applied hydrogen research	Scientific-technical agreements and specifications to support the redaction of the Trentino Hydrogen Roadmap	Autonomous Province of Trento; Research Institutes.	Research and Innovation
P6	Widespread installation of rooftop photovoltai c systems on buildings	Analysis of compatibility between **photovoltaic plants** and specific landscape and architectural values and development of an **abacus** aimed at the revision and simplification of urban autorization procedures on buildings subject to the discipline of historical settlements and traditional building heritage and subject to landscape constraints	Autonomous Province of Trento	Facilitatory
P7	Areas for energy production	Identification of specific areas in planning instruments - including supra-municipal - for the localization of **technological services for energy production.** Binding implementation to landscape and environmental criteria.	Autonomous Province of Trento; Consortium of Municipalities Valley Communities	Regulatory-programmatic
P8	Energy analysis at the planning stage	To study the **energy potential of areas** earmarked for attuative plans or art. 110 L.P.15/2015, already at the planning stage (municipal or supra-municipal), also with a view to encouraging the Energy Communities.	Autonomous Province of Trento; Consortium of Municipalities	Regulatory-programmatic

Cod.	Action Title	Description	Actors Involved	Typology of Action
P9	Regular climate-conscious planning	Bring **climate goals into the** ordinary planning instruments PRG, PTC. by amending Urban Planning Law 15/2015.	Autonomous Province of Trento	Regulations
P10	Regulatory update	**Updating provincial plans** by adapting them to the needs of adaptation and mitigation to climate change, sustainable construction, energy communities, amending the Urbanisti- c Law 1/2008 and Urban Planning Law 15/2015	Autonomous Province of Trento	Regulations
P11	Implementation plans, premiums and Energy Community	In-depth energy analysis within the Implementation Plans and the interventions under Art.110 of P.L.15/2015 that allows for a possible premium and encourages the **emergence of Energy Communities**.	Autonomous Province of Trento; Consortium of Municipalities Valley Communities Pilot Municipalities	Regulatory-Programmatic

Table 8. Green hydrogen in Trentino to 2030

2.4 Provincial decarbonization scenarios to 2030 - Water source forecast scenarios.

This chapter considers the various factors that may contribute to a positive or negative variation in provincial annual hydropower production from water sources, such as climate change, regulatory and Plan of Interest indications regarding new derivations or reallocations, possible expansions and/or efficiencies of existing plants, and priorities for use of the water resource.

From current knowledge, this results in a substantial invariance of the current level of production on the existing one, considering a balancing on the one hand of the efficiency upgrading of plants under renewal, and on the other hand the possible prescriptions in terms of non-usable flows or competing uses to be prioritized, as a result of Environmental Impact Assessments, in application of the regulations. Moreover, by 2030, models show that climate change will have the effect of reshaping outputs on a sub-annual basis but not altering annual outputs.

Regarding the ecological-environmental aspects related to the use of the water resource for hydropower, including considerations also at the level of protected areas, useful references are already contained in the plans strictly relevant to the topic, namely the Water Protection Plan (PTA) and the General Plan for Public Water Use (PGUAP), with the relevant updates provided for and referred to in the paragraphs, which, it is believed, could also lead to contractions in derivable flows.

As far as new concessions are concerned, considering that, as indicated in the PGUAP, the construction of new plants above 3 MW of average annual rated capacity is not possible, it is possible to consider as likely the scenario that in the next decade the increase in capacity attributable to new derivations below this power threshold will be very residual. In this regard, reference should be made to Article 18 ter, introduced by Article 12 of Provincial Law No. 6 of April 23, 2021, in Provincial Law No. 18/1976, which expressly provides for a moratorium on new applications until the updating of the Water Protection Plan (PTA) is approved, therefore, even taking into account the percentage of nominal power allocated to averages (about 11.5%), the overall structure of hydropower production will not undergo a significant change in the Trentino territory. To this it should be added that, due to the new regulations on renewals, with regard to renewal applications on medium hydroelectric derivations (> 220; < 3000), an in-depth assessment in compliance with the PTA and "further environmental criteria identified in advance in relation to the specific characteristics of each concession for the definition of its content" is foreseen.

2.4.1 Status of nominal powers and hydropower production

As reported in the provincial energy balance, a characterizing element of the Trentino energy system is the abundant electricity production (5,489 GWh), which exceeds provincial electricity consumption (3,322 GWh) by 65 percent. In addition, 83% of electricity production is from renewable sources, with hydro (normalized, DM March 11, 2012 - Burden Sharing Decree) at 4,321 GWh, which alone exceeds provincial energy needs. This figure once again reflects the strategic value played by this renewable source, which among other advantages also has the possibility, thanks to the programmability of operation, to favor the balancing of the national electricity grid.

The complete production figure for each individual generating plant underlying each concession is not available to date, so the breakdown according to the administrative powers of the concessions is shown in Table below.

The size classification proposed here reflects the commonly accepted and internationally codified classification from a technical point of view:

- Micro hydro (up to 100 kW);
- Mini hydro (100 kW to 1 MW);
- Small hydro (1 MW to 10 MW);
- Large hydropower (over 10 MW).

Mean yearly nominal power				
Micro	**Mini**	**Small**	**Large**	**Totale**
< 100 kW	100 - 1000 kW	1000-10.000 kW	> 10.000 kW	-
7.076,00 kW	44.054,90 kW	126.393,45 kW	494.518,84 kW	672.043,195 kW
1,1%	6,6%	19,8%	73,6%	100%

Table 9. Technical distribution according to the average annual rated power of concessions in the province of Trento as of the year 2020.

The classification from an administrative point of view is also reported, representing the power bands provided for by the Consolidated Text on Public Waters and Electric Installations (Royal Decree No. 1775/1933) and also according to the indications of the law of the Autonomous Province of Bolzano.

Mean yearly nominal power			
Administrative classification from “Testo unico 1775/1933”	Small		Large
Classification “ex Capo II bis p.p.. 1976”	Small	Medium	Large
	0-220 kW	220-3000 kW	>3000 kW
Mean yearly power	14.192,24 kW	77.476,10 kW	580.374,86 kW
Percentual power	2,1%	11,5%	86,4%

Table 10. Administrative distribution according to the average annual rated power of concessions in the province of Trento as of the year 2020.

With reference to 2016, it was possible to obtain the production data of a good part of the 20 large hydroelectric derivation plants operated by the Province of Trento, according to the classification under the administrative profile (>3,000 kW).

Of these, data from plants with energy feed-in points on the provincial territory were analyzed in order to compare the data with the total data from Terna and thus be able to analyze the distribution under the administrative profile according to energy fed into the grid.

Analyzing the production data shows that the large hydroelectric derivation plants whose production is known fed 2,750 GWh into the grid in 2016, out of a total of 3,251 GWh in the provincial territory, corresponding to 85 percent coverage.

This figure, although incomplete, thus indicates the centrality of the renewal of large hydroelectric concessions in the energy landscape of the next decade.

2.4.2 Reallocation of large water derivation concessions for hydroelectric purposes

Given the predominance both in terms of administrative power granted and in terms of energy input to the grid of large hydroelectric derivation plants, it was deemed a priority to focus the elaboration of this scenario on those plants that refer to the concessions to be reallocated, according to the regulations provided by Provincial Law March 6, 1998, No. 4 for as amended by Provincial Law of October 21, 2020, No. 9.

In fact, the reallocation, by December 31, 2023, of 17 of the 20 large hydroelectric derivations for which the Province exercises the administrative functions inherent in the relevant concessions is envisaged; this deadline could slip to July 31, 2024 as a result of amendments that could be made to Article 13 of the Statute of Autonomy, due to the alignment with the terms indicated in the state law (Article 12 of Legislative Decree No. 79/1999, per as last amended by Article 11-quater, paragraph 1 of Law No. 12 of 2019). The other 3 large derivations, on the other hand, have their expiration dates set for 2025, 2027 and 2032. It should be noted that the concession of large water derivation for hydroelectric purposes in San Floriano, located on an overlap with the territory of the Autonomous Province of Bolzano, was reallocated by the same Province until Dec. 31, 2040.

In any case, Provincial Law March 6, 1998, No. 4, Article 26f, in order to ensure continuity in energy production, provides that the derivations are to be exercised by the outgoing concessionaire under the same conditions until the new concessionaire takes over.

New concessions are likely to take effect on average from 2025. For the purposes of this Plan study, which considers a time period between 2021 and 2030, it is therefore possible to envisage two distinct phases within the decade of interest:

- 1st phase: 2021-2025: current production regime
- 2nd phase: 2025-2030: new production regime

The following paragraphs outline the issues that could affect the renewal of the upcoming large hydroelectric derivations.

2.4.3 Possible changes on hydropower production at the same derived flow rate

With the same derived flow rate, there are two cases that can generate a variation in hydropower production: a different yield of the plants and a variation in the head exploited.

In the first case, as a result of technological advancement, it is possible to assume an improvement in the efficiency of the plants, albeit to a minimal extent, given the strong level of development of hydropower already in the last century.

The degree of efficiency, along with the state of conservation of the assets and their operation, is the subject of a specific addition to the end-of-connection report introduced by Law No. 9/2020.

In fact, the province must develop a plan of interventions for the concession in order to maintain the hydropower facilities in an adequate state of efficiency over time. The points of attention are as follows:

1) good use of water, i.e., avoidance of water losses;

2) efficiency of machinery, an issue that will be the subject of proposal by the bidding parties;

3) possibility of increasing power generation by making the best use of residual salts not yet used.

As part of the criteria set by the aforementioned provincial law for awarding the concession, there is also a specific bonus for making, in the first 5 years of the concession, investments that allow an increase in productivity and efficiency.

Given the 5 years given to fine-tune the planned interventions, it is plausible to assume that by 2030, corresponding to the time horizon of this study, there will be no appreciable changes due to this factor. Therefore, it is plausible to assume that no interventions will be made to large hydropower plants in the next decade that would alter power generation at the same derived flow rate. Instead, such interventions could affect from 2030 onward and will therefore be the subject of subsequent analysis.

2.4.4 Effects of climate change on hydropower generation

As a result of the elaborations carried out for the Orientgate Project, which take into account the climate forcings reported in Chapter 2, Section 1, Part Two, it was possible to make considerations, given below, on how climate change may affect the behavior of hydropower derivations in the 2021-2030 decade.

The project looked at the 30-year reference periods 2021-2050 and 2041-2070, thus well beyond the time period covered by this study. However, the analyses performed provide insight into potential temporal evolutions of hydropower production.

Given the complexity of the Trentino territory, the project examined two sample basins, that of the Noce River and that of the Brenta River, which, presenting different geomorphological characteristics and anthropogenic pressure between them, could provide representative indications of the entire provincial territory. In fact, in the Noce basin, unlike the Brenta basin, there are important glacial areas and several hydroelectric exploitation systems that use seasonally compensating storage reservoirs.

While in the Brenta River basin, the large hydropower systems present possess storage reservoirs of limited size, which can be considered daily or sub-daily regulated and thus have a behavior quite similar to flowing water systems.

Within the pilot project, it was possible to use a hydrological model to predict the effects of climate change on water resource availability, taking into account the influences of upstream diversions.

In the project, a general decrease in production, in terms of theoretical producible power (understood as the flow derived for the motor jump), is predicted to be more pronounced for the Brenta basin and Val di Non. As with the forecasts of riverbed outflows in the natural scenarios, discordant production trends are expected in the short term (2021-2050) between the two emission scenarios RCP4.5 and RCP8.5, while the forecast realigns in the second period (2041- 2070) . Specifically for the next 30 years, a decrease in total annual theoretical power is expected in the Brenta basin ranging from 20% to 3%, depending on the two climate scenarios; unlike the Noce basin where the forecast range shows a 12% decrease for the RCP4.5 scenario, and a 3% increase for RCP8.5.

At the seasonal level, even more significant changes are expected. In summer and autumn, the scarcity of water resources already observed for the natural scenarios will lead to drastic declines in production compared to the 1981-2010 period: in some systems in the Non Valley and Brenta basin, declines of between 25 and 50 percent are expected in the medium term, with further declines in the next 30 years. While in winter, the expected growth in riverbed runoff will lead to an increase in overall production, with basin-scale increases that could exceed 25 percent. Finally, in the spring season in the small plants of the Brenta River basin and Val di Non there is a widespread decrease in theoretical producible power, while in Val di Sole an increase is expected, due to the contribution from snowmelt. The study showed that in addition to the size of the plants, it is also necessary to consider the type of operation of the derivation: whether flowing water or with a storage/compensation basin.

The operation of flowing water derivations is in fact directly related to the outflows flowing in the riverbed and therefore their response to climate change is closely related to that expected for the availability of natural water resource. For these types of derivations in both basins studied, annual decreases in production are expected, while at the seasonal level changes are expected even more important.

In contrast, plants connected to large storage reservoirs also have the ability to manage input volumes on an annual scale, influencing the hydrological regime downstream of them; thus they are less subject to the effects of seasonal variability in resource availability. In fact, the results of the pilot project for large hydropower systems in the Walnut Basin show greater resilience to seasonal variations induced by climate change, managing to partially offset them. The higher winter inflows, however, only partially succeed in offsetting the summer decline, which could negatively affect GDI hydropower production precisely in the months of June through September.

The significant forecasting range observed for the next 30 years in the two emission scenarios allows the results obtained for the two study basins within the OrientGate project to be extended only qualitatively to the entire province.

In addition, just as in Chapter 2 of Section 1 (Assumptions) regarding natural runoff, considering that the time period covered by this study is 2021-2030, which is more limited than that of the first 30-year period of analysis, it was considered plausible to keep total annual runoff unchanged. Instead, variations may be observed on a sub-annual basis, such that reservoir management may need to be different, but these should not affect overall hydropower production. Over the period 2030-2050, climatological scenarios show likely reductions related to derivable flows, which will be the subject of subsequent analysis.

2.4.5 Update of the Water Protection Plan

Among the various issues addressed in the Water Protection Plan, those that could directly affect the availability of water resources that can also be used for hydropower production are:

- the program of measures on water bodies at risk of not achieving or not maintaining quality objectives to 2027, defined from the results derived from the updated knowledge framework, including the analysis of pressures and significant impacts;

- the application of the Environmental Criteria for the definition of the content of concessions of large water derivations for hydroelectric purposes (art. 1 bis 1 paragraph 1.1 of P.L. 4/1998), which may imply the redefinition of the concession parameters and the management modalities of the plants according to what will emerge from the required cognitive insights and the environmental assessment process;

- the possible revision of the provincial regulations on water derivations as a result of the adjustment to the contents of the Directorate Decrees No.29/ STA dated 13.02.2017, approving the Guidelines for ex ante environmental assessments of water derivations, and No.30/STA dated 13.02.2017, approving the Guidelines for updating the methods for determining the minimum vital runoff in order to ensure the maintenance of ecological runoff in watercourses. The possible application of new rules resulting from the adjustment to the above-mentioned Directorate Decrees could affect both the development of new hydroelectric initiatives and the current energy production of even large hydroelectric derivations, since in the renewal and reallocation phase of concessions, adjustments to the current concession parameters may be required in favor of the recovery of the quality status of those water bodies, directly impacted by the system, that do not achieve quality objectives or in support of precarious situations, including due to the presence of anthropogenic pressures of other types.

- the implementing rules of the PTA, which, depending on the overall framework related to the various themes of the plan, may provide for new constraints and/or requirements inherent in the issuance/renewal or reallocation of water derivation concessions.

Given that the timing of the drafting and approval of the Water Protection Plan update exceeds that of this document, and given the clear connection and possible impact of the issues listed above on hydropower production, we will follow the progress of the work of the various tables to subsequently quantify, where possible, the influences on the flows actually available for hydropower production in consideration of the various issues addressed. To date, however, such quantification is not possible. It was therefore decided not to consider changes resulting from the issues listed above and to keep the derivable flows unchanged, pending the new Water Protection Plan.

2.4.6 Prevailing and competing uses

The issue of water uses prevailing over hydropower concerns both the reallocation of large hydropower derivations and the renewal of small hydropower derivations, since they are both procedures affected, as a preliminary matter, by the assessment of the environmental impact and public interests related to the possible continuation of hydropower use of the water resource for a long period (maximum of 30 years).

The following uses should definitely be considered to take precedence over hydropower, by regulatory provisions:

- Environmental/landscape use, i.e., the maintenance of the resource in its natural setting for the benefit of the environment, landscape and thus the public interest in preserving them;
- Hydropotable use, understood as the primary use of the resource for human sustenance and health;
- Irrigation and aquaculture use, understood as the primary use because it is for human sustenance, localized and as such irreplaceable of the resource.

It may also be considered, as a prevailing use of the resource, if it is impossible to continue its hydroelectric use - in whole or in part, for reasons of public safety (e.g., due to geological instability).

Thus, with regard to the aforementioned prevalent uses, it is believed that, in light of current knowledge, experience gained in public water management, and the critical issues that have emerged to date, the possible impact on the flows available for hydroelectric use is extremely limited in percentage terms.

The criticalities that have emerged so far, in fact, do not concern so much the derived quantities, but rather the way in which they are stored and used; this could affect the reduction of the economic value of the energy produced and sold on the electricity market as well as, consequently, the variable share of the fees for the assets given for use under Article 1 bis 1.3 of Provincial Law no. 4/1998.

We can therefore conservatively estimate that the possible impact of prevailing uses on water availability for hydropower purposes may be contained in 1% overall at the provincial level (equal to about 6 cu m/s).

Among the remaining water uses other than hydropower, with respect to those highlighted in the previous point, the decision regarding the possible privilege of the same (and possible limitations to the privilege itself) is not directly dictated by legislation but, possibly, by programming and planning acts that must be taken by the Provincial Council, in implementation of general forecasts provided for by law, currently limited to large hydroelectric derivations (art. 1 bis 1.1 of Provincial Law no. 4/1998 - "Verification of the existence of interests in concurrent use of water").

This rule has not yet been implemented with the planned resolution on priority criteria for new uses competing with hydroelectricity, so predictions about their possible impact are particularly arduous.

However, reference can be made to the similar provision of priority for different uses of water that was enshrined in the same Provincial Law No. 4/1998 regarding the 10-year extension period for large hydroelectric derivations (Art. 1a 1, para. 15b); in this context - by resolution no. 2042 of 09/28/2012 and other subsequent ones - modalities and quotas of the water reserve destined by law for any different uses of water requested by third parties during the aforementioned 10-year extension period were established, for an overall total of about 6 cu m/s.

The experience gained in this context, with requests for making the water reserve available over a decade being much lower than the total assumed, leads us to believe that the maximum flow rate indicated above (6 mc/s) is largely sufficient to guarantee both the probable confirmation of requests for making the water reserve available and any new requests for competing uses, including any competing hydroelectric requests from self-producers that might be preferred over the current use by the GDIs (albeit in the face of lower efficiency of the same).

We can therefore assume, again conservatively, that the possible impact of competing uses on the water availability for hydropower purposes of the large derivations alone could be contained in 1% overall at the provincial level (equal to about 6 mc/s, assuming for simplicity that the flow available for GDIs is that overall). This impact, added to the aforementioned possible impact of the prevalent uses, can therefore be estimated overall and in broadly conservative terms at 2% of the available flow rate.

Therefore, assuming for further simplification that the impact is on average homogeneous across all hydropower derivations, the prediction of the possible cumulative impact of new prevailing and competing uses on Trentino's hydropower production over the next decade does not exceed 2%.

2.4.7 New hydroelectric derivation concessions

By resolution of the Provincial Council. no. 2775 dated Dec. 14, 2012 and no. 2991 dated Dec. 27, 2012, the Provincial Agency for Water Resources and Energy is assigned the function inherent in the issuance of concessions and other measures relating to the use of public waters, among which the use for hydroelectric purposes is of particular importance. This function was carried out, until December 31, 2012, by the Public Water Utilization Service.

In recent years, there has been a significant decrease in the trend of new small water derivation plants for hydroelectric purposes and, consequently, of installed power. Given the constraint established by the PGUAP to prohibit new large hydroelectric derivations and on the basis of the evaluations carried out by the competent offices regarding the environmental constraints in force for new small hydroelectric derivations and the conditions for the renewal of existing ones, it is possible to consider plausible the scenario that foresees that in the next decade the increase in power attributable to new derivations will be very residual; therefore, the overall structure of hydroelectric power production will not increase in the Trentino territory.

This clearly does not mean that at the local level any new concessions will not allow changes to existing arrangements, however for planning purposes the overall contribution that can be generated by them will not be able to exceed very few percentage points.

2.4.8 Economic optimization of plants and energy storage: pumping systems

A possible further development concerning large hydropower derivations concerns pumping for the purpose of recharging upstream reservoirs at times when the cost of energy is convenient for this operation; the stored water is then turbined at times of higher energy demand.

In addition, the pumping activity, which is also envisaged in the PNIEC - National Integrated Energy and Climate Plan - scenarios, plays an important role, also from an environmental point of view, because it allows electricity produced from unregulated renewable sources to be stored, and subsequently made available continuously for the benefit of end users, thus generating indirect environmental benefits. From the provincial perspective, this measure allows for an increase in the amount of total energy produced in the provincial territory, however, at the expense of an increase in energy consumption.

Provincial guidelines are in favor of including the possibility of pumping.

To date, there are already hydropower plants that provide for such pumping. It is also considered possible to expand this activity by extending it to other plants where only existing artificial reservoirs can be used, avoiding significant impacts on the achievement/maintenance of water body quality objectives. This is in order to protect natural lakes and the quality of waterways.

It is also worth mentioning that even run-of-river plants include the possibility of storing electricity, produced at times of lower demand for use or return to the grid at a later time. This is possible through the use of other storage systems, such as the installation of battery systems and hydrogen production. However, such proposals will have to be evaluated on a case-by-case basis, considering cost-effectiveness and environmental protection, degree of innovation, and any other parameters deemed useful for approval.

2.4.9 Conclusions

In the preceding paragraphs, factors that may have influences on hydropower production in the next decade have been analysed.

The balancing of several concomitant factors, some that could lead to an increase in electricity production, such as the efficiency upgrading of plants under renovation, and others to its decrease, such as possible prescriptions in terms of flows that cannot be used or competing uses to be favored, as a result of Environmental Impact Assessments and from possible limits introduced by the update of the Water Protection Plan for the six-year period 2021- 2027, mean that in this Plan it has been assumed valid to maintain a substantial invariance of the current level of production from hydropower.

Specifically, over the time frame of the Plan, no significant change is expected as a result of investments on large hydroelectric derivations such as to lead to an increase in plant productivity and efficiency.

The possible effects of climate change were also assessed, concluding that by 2030 there will be no significant reductions in the annual amount of runoff, although it will result in sub-annual variation.

Da ultimo sono state considerate le dinamiche legate agli usi prevalenti e usi concorrenti valutati ai fini della riassegnazione delle grandi derivazioni idroelettriche, per, i quali si stima che potrebbero influire al 2030 con una riduzione complessiva della disponibilità idrica a scopo idroelettrico stimabile fino al 2%.

Lastly, the dynamics related to prevailing and competing uses assessed for the purpose of reallocation of large hydropower derivations were considered, for, which it is estimated could affect by 2030 with an overall reduction in water availability for hydropower purposes estimated at up to 2 percent.

Measures resulting from the update of the Water Protection Plan will also be monitored, regarding which to date it is not possible to predict how these will affect derivable flows. As a result of these considerations, it was concluded that in the decade 2021-2030 it is possible to consider the share of energy attributable to hydropower as constant, not as an invariance of the use of the water resource but as a result of possible conflicting effects.

In particular, given the dominance of large derivations in the coverage of hydropower generation, it is possible to envisage two distinct phases within the decade of interest:

- 1st phase: 2021-2025: possible start of production with "new rules": 2024 (as a result of the bidding process with presence of appeals)
- 2nd phase: 2025-2030: new production regime, but this will not significantly alter total production.

It is specified that these are considerations aimed at quantifying annual production on a provincial scale over the next decade. Then, by going into the merits of individual situations, it will be possible to identify the potential for expansion or necessary restrictions of individual river reaches and facilities.

3 Development of an integrated solution and identification of technologies and works required to realize the project in relation to the spatial context

3.1 Analysis of possible sources

The renewable resource was identified taking into consideration the following factors:

- On-site availability of the resource
- Available areas
- Environmental and landscape constraints.

The resources considered are:

- Solar photovoltaic
- Wind power
- Hydroelectric

Among the resource types, only the photovoltaic resource was identified, in fact:

- The wind resource was excluded for reasons related to landscape impacts.

- The hydro resource was, at the moment, excluded because it needs a detailed study on the residual availability of the plants already in operation that could potentially "allocate" part of the energy produced to the territory and not for feeding into the grid. The new regulations regarding Renewable Energy Communities allow the electricity produced in the area of the primary cabin to be used directly in the territory then further investigations are needed.

3.2 Background and assessments of Wind Energy

The analysis of the sites of the municipalities showed that on the Trento region there are landscape constraints and therefore the wind resource cannot be considered.

Regarding the production of electricity from wind farms currently present, it is clarified that they are being experimented on Trentino territory therefore not significant.

Below is an excerpt from the PEAP that reiterates the above.

Regarding the wind resource, as part of the project "Trentino Climate Atlas," promoted by the Trentino Climate Observatory and financed through the Climate Change Fund of the Autonomous Province of Trento, maps of wind speed and the scale and shape parameters of the Weibull distribution were made, *forming part of the 2004-2013 Wind Atlas. Based on this work and experiments already implemented in the province, this resource is not expected to have a significant impact on the provincial energy mix. Investment supports at the provincial scale in the future for increasing shares of renewable energy must become more efficient, create economies of scale, lead to greater market integration and consequently a more supra-local approach, and at the same time encourage and support distributed generation with a view to increasing self-consumption.*

3.3 Background and assessments on Hydropower source

The following is an excerpt from the PEAP in which the area's hydropower resource is detailed. The analysis is useful pe define the potential and applicability of the source to the context.

The distribution under the administrative profile based on the average annual nominal power of the concessions present in the province of Trento as of the year 2020 sees 86% of the power attributable to large hydroelectric power plants.

It was therefore considered a priority to focus the analysis on those plants that refer to the concessions to be reallocated, according to the regulations provided by Provincial Law March 6, 1998, no. 4 for as amended by Provincial Law of October 21, 2020, no. 9.

For the purposes of the study of this Plan, given the expiration of the concessions and the possible slippage for alignment with the national discipline, it is possible to envisage two distinct phases within the decade of interest:

- *Phase 1: 2021-2025: current production regime*
- *Phase 2: 2025-2030: new production regime.*

Within the criteria set by the aforementioned provincial law for the awarding of the concession, there is also a specific bonus for making, in the first 5 years of the concession, investments that enable an increase in productivity and efficiency.

Given the 5 years given for the fine-tuning of the planned interventions, it is plausible to assume that by 2030, corresponding to the time horizon of this Plan, there will be no appreciable changes due to this factor.

The possible effects of climate change were also considered, concluding that by 2030 there will be no significant reductions in the annual amount of runoff. Instead, changes may be observed on a sub-annual basis, such that reservoir management may need to be different, but these should not affect overall hydropower production. Over the period 2030-2050, climatological scenarios show likely reductions relative to derivable flows, which will be the subject of subsequent analysis. However, these changes could be offset by the interventions of the concessionaires, which are estimated to come into operation towards the end of the 2021-2030 decade.

Lastly, dynamics related to prevailing and competing uses have been considered, which are estimated to affect 2030 with an overall reduction in water availability for hydropower purposes of up to 2 percent.

Measures resulting from the update of the Water Protection Plan, regarding which to date it is not possible to predict how they will affect derivable flows, will also be monitored.

As a result of these considerations, it has been concluded that in the decade 2021-2030 it is possible to maintain a substantial invariance of the current level of production from hydropower, balancing on the one hand the efficiency of the plants being renewed, and on the other hand the possible prescriptions in terms of non-usable flows (Ecological Outflow) or competing uses to be favored, as a result of the Environmental Impact Assessments.

The above considerations and the current unavailability of precise data on flow availability do not allow for a detailed analysis of the scenario that also includes hydropower as a renewable resource.

3.4 Background and assessments on photovoltaic

Solar PV, after an analysis comparing other technologies and resources, has been shown to be the only system that can guarantee H2 production while at the same time not significantly impacting the landscape.

The use of PV involves a configuration in which electricity is generated to serve an electrolyzer system, a daily storage system, and a seasonal storage system.

In addition to the equipment already mentioned, dedicated compressors and circuits (piping, filter valves, etc.) are to be provided.

4 System Layout

The basic element of the system is the H2 production plant, that will be considered in the three scenarios.

The plant involves the production of hydrogen, by electrolysis, from water available at the site, this water will have to be properly treated and filtered. The electrolysis will be "sustained" by electricity from the photovoltaic array.

Given the high purity levels required for the electrolyzer feedwater, a treatment plant will be installed upstream of the hydrogen production system.

The power required for the electrolyzer will be provided by a section of a dedicated photovoltaic system that will also power all the system's auxiliaries.

The electrolysis plant, in addition to the main outlet, includes two chimneys that will be positioned in such a way as not to result in hazardous areas at the site; the first one the one related to hydrogen release, this one does not work continuously but only in coso of system problems or during purging processes. II second chimney is dedicated to the expulsion of oxygen; to avoid safety problems this will be placed at an appropriate distance from the hydrogen release system to the atmosphere.

The hydrogen produced will then pass into a dryer going to increase its purity from 99.9% at the outlet of the electrolyzer to 99.999% making it compliant with ISO 14687-2 and making it available for multiple uses. The remainder of the flow will consist of about 5 ppm aequo and another 5 ppm oxygen.

The gas generated is at a pressure just under 30 bar, which, given the density of hydrogen, is too low a value to ensure low-cost and efficient transport. For this reason, a compression plant has been set up where this value is raised to 200 bar. To avoid major flow and pressure fluctuations during compressor operation, which increase its degradation, a buffer is installed between the electrolysis and compression parts.

The configuration thus includes a daily buffer and a seasonal storage system, whose dimensions were defined on the basis of numerical simulations. In the case of H2 distribution, a trailer loading bay is built downstream of the storage system; the system allows the refueling of the trailers by drawing hydrogen from both the medium-pressure storage and the compressor, allowing the refueling of trailers at a pressure of 200 bar.

In the picture below a possible schematic of the principle and layout is reported.

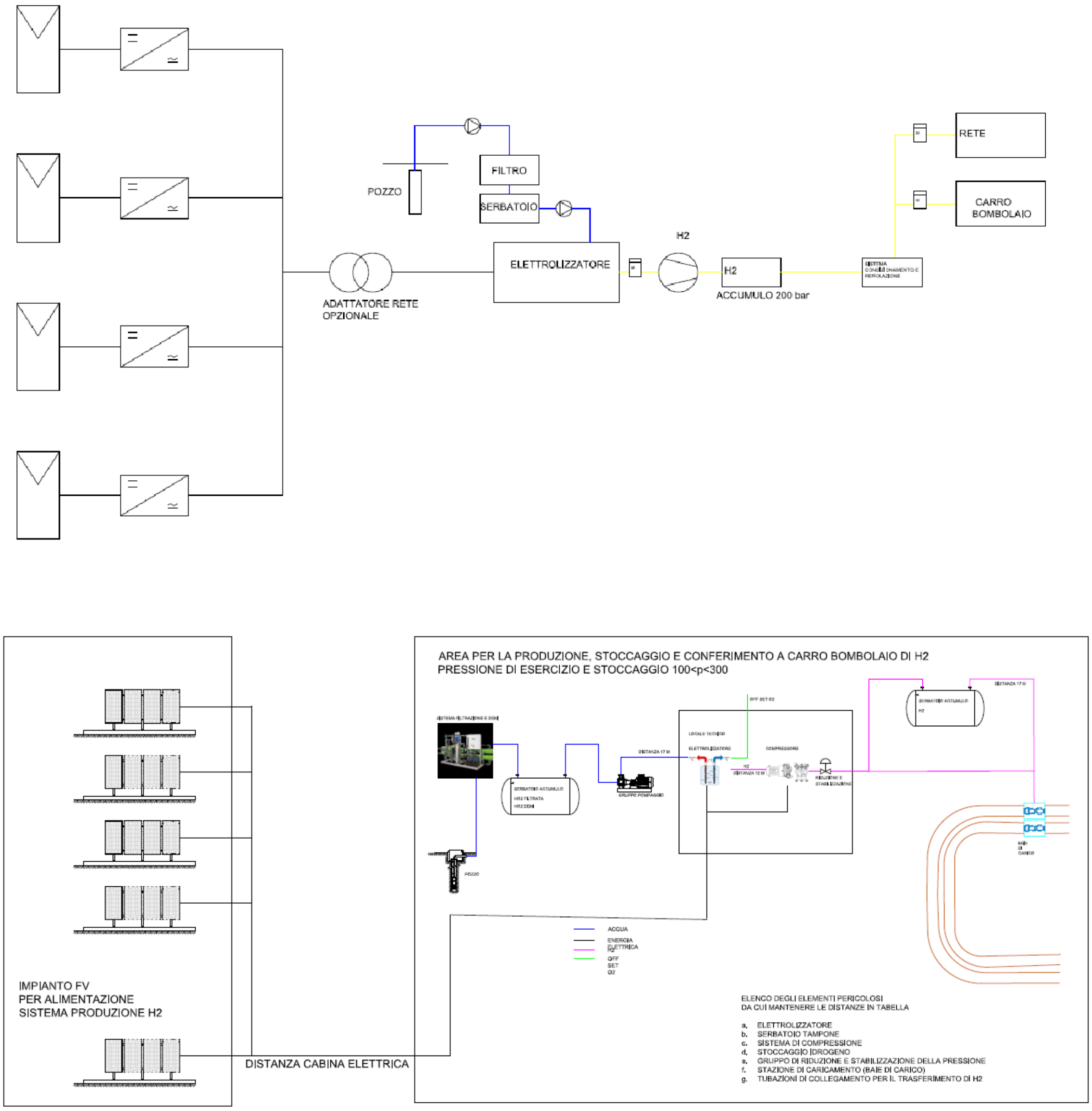


Figure 18. System functional scheme

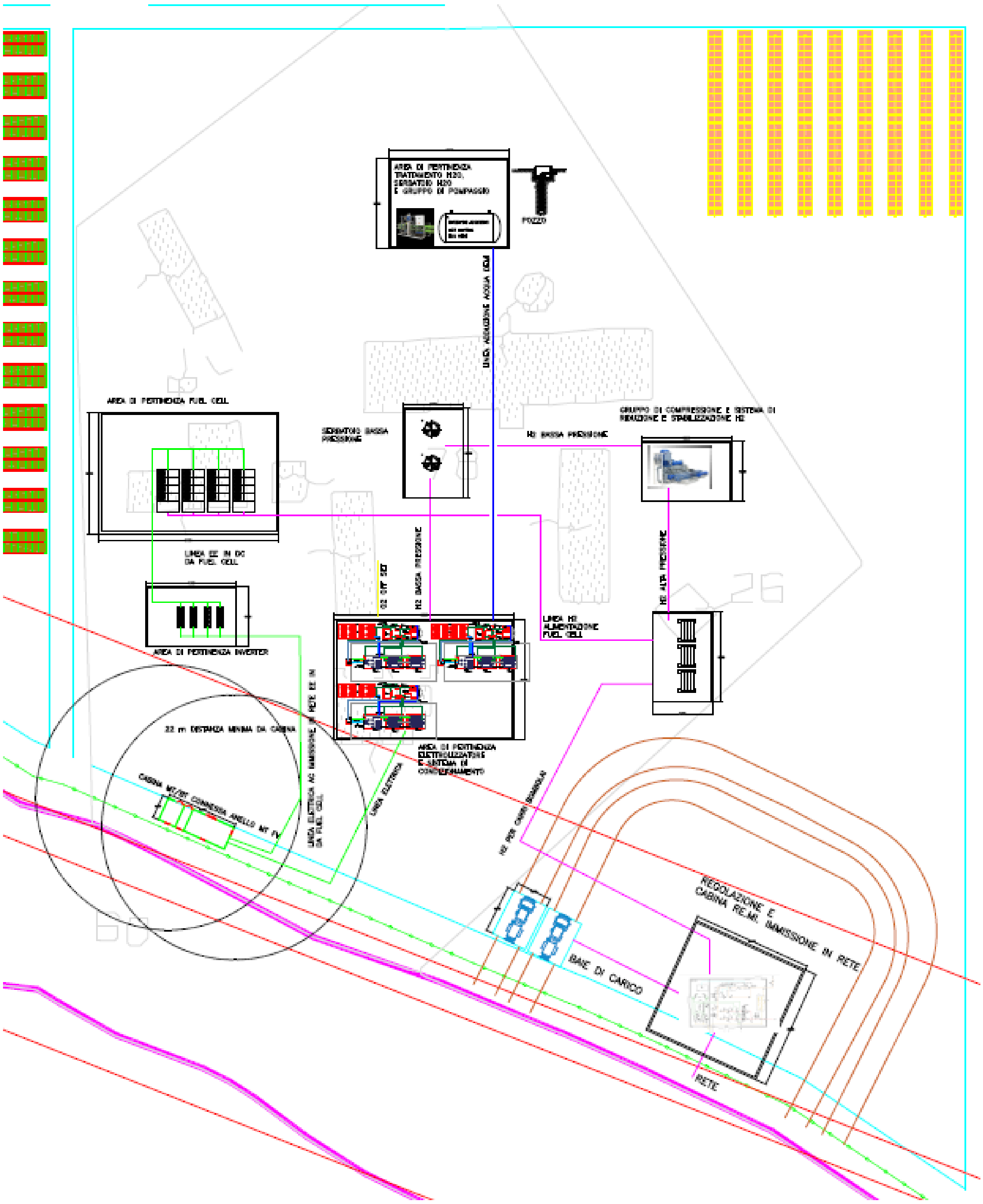


Figure 19. System Layout example

1) PV plant and electrolyzer

The project involves the production of green hydrogen on site through the combination of the PV array and the respective electrolysis plant.

II hydrogen production system will be realized with a containerized solution; which, in addition to facilitating the on-site installation, allows to make Ia solution modular and increase the power at a later stage of the project.

Each electrolyzer will be a complete "plug and play" system capable of converting, using electrical power, treated water into hydrogen with a purity that complies with regulations. In fact, inside the container are all the necessary components for the process: potassium hydroxide (KOH) management, electrolysis stack, hydrogen purification plant and color disposal unit. In contrast, the demineralized water production plant and its tank will be installed in a box outside the electrolyzer container.

To maximize the coupling with renewable sources, the proposed system includes a highly partializable technology, capable of operating in a power range of 3% to 1 00% with a high response speed.

No. 3 containers are planned several sets of electrolyzers in parallel, which, in addition to ensuring a high level of rongeobility, allow the system to remain operational even in the event of failure of one of the elements, losing only 3% of the nominal output. Unlike common 1 MW containerized systems, this solution avoids long shutdown times while waiting for a new component to arrive.

2) Buffer Storage

To ensure proper operation of the compression system and avoid sudden changes in pressure and/or flow, a storage buffer will be installed between the hydrogen production system and the compression system.

This system will be realized through a low-pressure tank suitable for hydrogen storage. The characteristics of the system are as follows:

Buffer Storage		
Nominal Pressure	8	bar
Operating Pressure	30	bar
Volume	variable depending on Scenarios	

Table 11. General buffer storage technical specifications

3) Compressor

The compressor system allows the hydrogen pressure to be raised from those generated by the electrolysis system to values suitable for transportation, feeding into the grid, or use in fuel cells.

The plant will be built in a light-covered enclosure suitable for an outdoor installation. Sensors will be installed inside it to check for possible gas leaks, presence of flames and fans to ensure proper air exchange.

Compression unit		
Maximum discharge pressure	200	bar
Minimum suction pressure	5	bar
Maximum flow rate	500	Nm^3/h
Electrical power	33,4	kW

Table 12. General compression unit technical specifications

4) H2 Storage

To allow for greater plant flexibility, the system includes an H2 storage section to allow for the possibility of using this energy carrier in the three configurations that will be examined.

The technical specifications of the storage systems are reported in the table below.

Seasonal storage		
Nominal Pressure	200	bar
Operating Pressure	30-200	bar
Volume	variable depending on Scenarios	

Table 13. General seasonal storage technical specifications

5) H_2 distribution - Trailer

For the distribution of hydrogen to the respective areas of use, the project envisages the construction of a dedicated area for the loading of tanker wagons where a ramp place will be provided to go to connect the trailer to the system.

To ensure the safety of the system as a whole, the loading bay will be shielded from the other components with perimeter walls constructed of reinforced concrete, or other non-combustible material of adequate mechanical strength. The area, as indicated in the October 23, 2018 decree, and constructed in such a way that the tractor can hook up the trailer and pull it even in an emergency cose without maneuvering (in the direction of leaving the facility).

5 System Modeling

5.1 Softwares adopted

In order to develop a dynamic model of the System, which includes all the different subsystems (sections) and the connections between them, Matlab® and Simulink® softwares were used. Simulink® is a graphical interface that is part of the well-known Matlab® computational and programming program from MathWorks, and it is a powerful tool for modeling and simulation of complex systems, such as the present one. Specifically, the Simscape® library, internal to Simulink, provides the user with various libraries of components of different type and nature (electrical, mechanical, piping components, thermal, etc.) and allows the connection of the same through Physical Signals representing lines (electricity, gas, liquid, etc.) or the flow of information from sensors.

Specifically, gas lines representing the flow of hydrogen produced by the electrolyzer, liquid lines for cooling water, thermal lines for heat exchanges between piping and tanks and the surrounding environment, and mechanical lines representing components in motion such as compressors, pumps, and valves are mainly involved in the System model. For the model of the photovoltaic system and the electrolyzer, Simulink was chosen instead, i.e., to adopt signals without specific physical properties, but only numerical ones. This choice is justified by the fact that the detailed modeling of these sections of the plant is quite complex and thus beyond the scope of analysis of the overall System behavior.

5.2 System Global Model

The System has been divided into five different macro-sections: PV field, electrolyzer, buffer storage, long-term storage and end users. The PV field generates the electrical power needed to produce the yearly amount of energy required from the electrolyzer to produce the amount of hydrogen required yearly to feed the burners (or the central burner in case of district heating scenario). This amount depends on the overall thermal energy given by the thermal loads (residential burners) to guarantee a certain number of hours of heating during the year.

The hydrogen produced by the electrolyzer, whose production profile follows the PV plant power curve (with some limits due to electrolyzer power regulation constraints), is then sent to a first storage section which has been called Buffer Storage Section. This section has the purpose of decoupling the hydrogen production (which is highly variable during the year) from the compressors power-on period. In fact, to optimize the compressors activity, it is necessary to limit their operating time period to night hours as well as to reduce their overall time of operation.

A control logic has been implemented to control the periods of buffer charge and discharge and the periods of the compressors switch-on.

At the end of the day, when the buffer storage has been charged and the PV production is over, the control logic opens the valve from buffer storage section to long-term storage section and contemporary switches on the compressors (buffer discharge phase).

The hydrogen flow then enters the compressor section and undergoes different stages of compression, which are meant to rise its pressure from the buffer storage values (2-30 bar) to the long-term storage ones (30-200 bar).

The same global model of the System has been used to run the simulations of all the different scenarios considered.

The Simulink® interface is reported in the picture below.

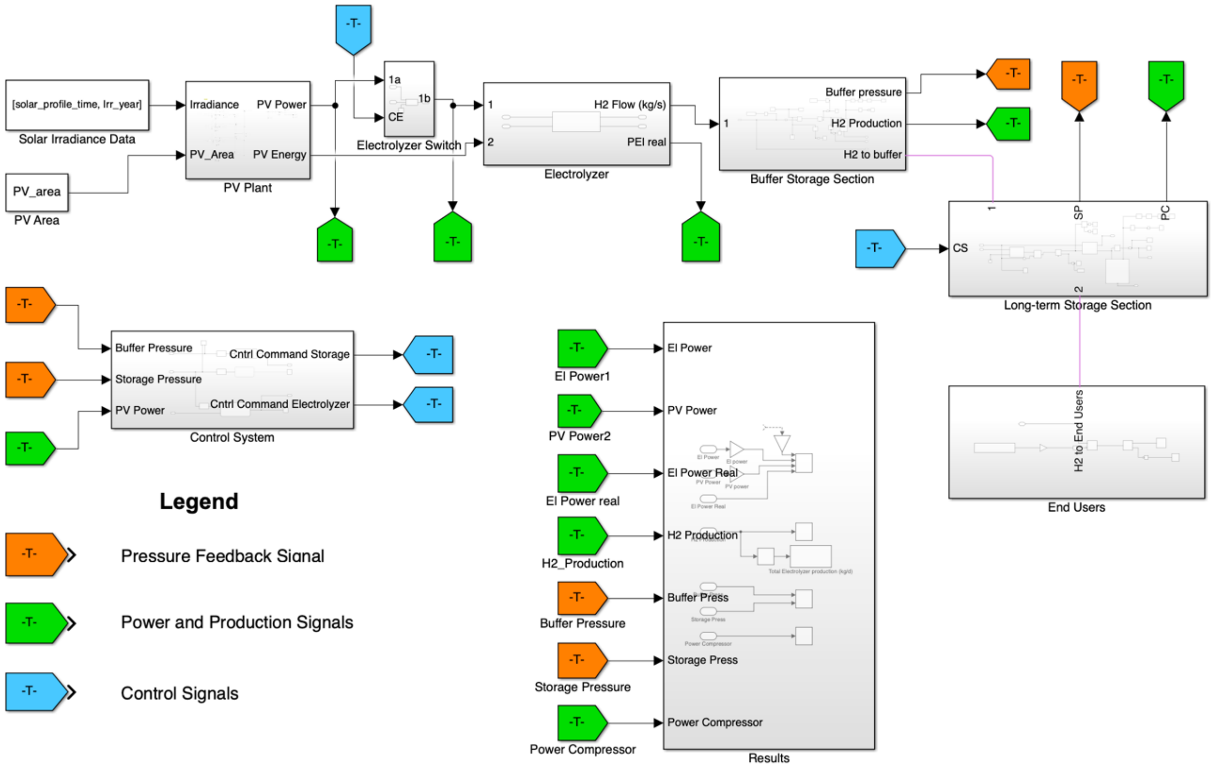
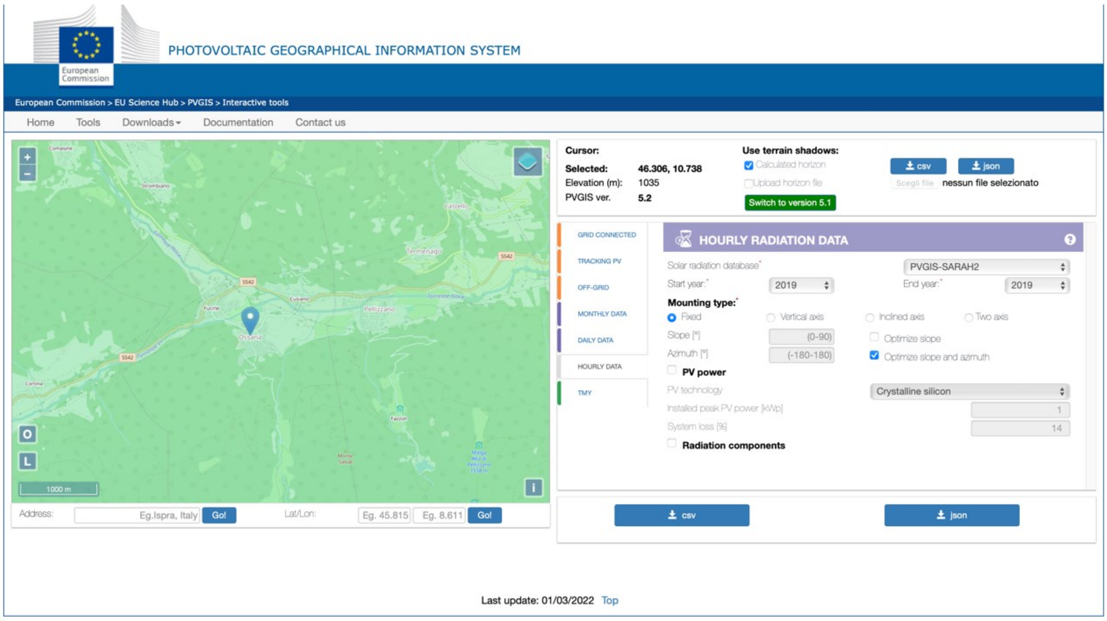


Figure 20. Global Simulink® model of the System

5.3 Unit sizing and Simulation parameters

5.3.1 PV Plant

The first step of the sizing procedure has been to collect the yearly irradiance data on the tilted plane relative to the chosen location for the PV plant (see paragraphs 5.1.1, 6.1.1 and 7.1.1). These data, together with the optimal azimuth and tilt (or slope) of the PV structures, has been collected from the European database PVGIS. For the duty of completeness, the interface of the website for the locality of Ossana (Peio) is reported below.



Cursor:
Selected: 46.306, 10.738
Elevation (m): 1035
PVGIS ver. 5.2
Use terrain shadows:
☑ Calculated horizon
☐ Upload horizon file
nessun file selezionato
Solar radiation database*: PVGIS-SARAH2
Start year:* 2019
End year:* 2019
Mounting type:*
● Fixed ○ Vertical axis ○ Inclined axis ○ Two axis
Slope [°] (0-90)
Azimuth [°] (-180-180)
☐ Optimize slope
☑ Optimize slope and azimuth
☐ PV power
PV technology: Crystalline silicon
Installed peak PV power [kWp]: 1
System loss [%]: 14
☐ Radiation components
Address: Eg.Ispra, Italy
Lat/Lon: Eg. 45.815 Eg. 8.611

Figure 21. Interface of PVGIS online database

The online database gives you the possibility to choose: the solar radiation database used; the typology of the PV structures (fixed, single axis trackers or two axis trackers); the reference time for data collection; slope and azimuth of the PV structures; sampling frequency of the irradiation data to collect (monthly, daily, hourly).

For all the scenarios considered, the hourly data for the years 2019 and 2020 on fixed structures with optimized azimuth and slope has been considered (see picture above), restricted over a period starting from September the 1°, 2019 and ending in August the 31°, 2020. This period has been chosen as the reference year to run the simulation, since it coincides with the starting of the heating period (September 1) and ends the last day of summertime (August 31).

The size of the PV plant and the resulting nominal power installed depend on the yearly electrical energy required from the electrolyzer to produce the desired amount of hydrogen to match the thermal energy loads.

Consequently, the hourly hydrogen consumption data for a given scenario have been considered to calculate the overall hydrogen production required from the electrolyzer. Hourly hydrogen consumption data have been calculated based on the hourly thermal energy loads (if available) or extrapolated from the yearly thermal energy consumption by splitting this value to a hourly distribution based on the temperature profile of the relative location. The thermal loads distribution curves for each scenario are reported in the paragraphs 6.2, 7.2, and 8.2.

5.3.2 Electrolyzer

The next step consists in the sizing procedure of the electrolyzer, according to the resulting nominal power of the PV plant and with the aim to obtain an overall hydrogen production at least equal to the amount required to satisfy the yearly thermal energy load.

A Proton Exchange Membrane Electrolyzer (PEMEL) has been taken into consideration due to its high efficiency (about 60%) and its actual commercial availability. The Simulink® model of this subsystem (the in-deep electrolyzer model is not reported) is shown in the picture below.

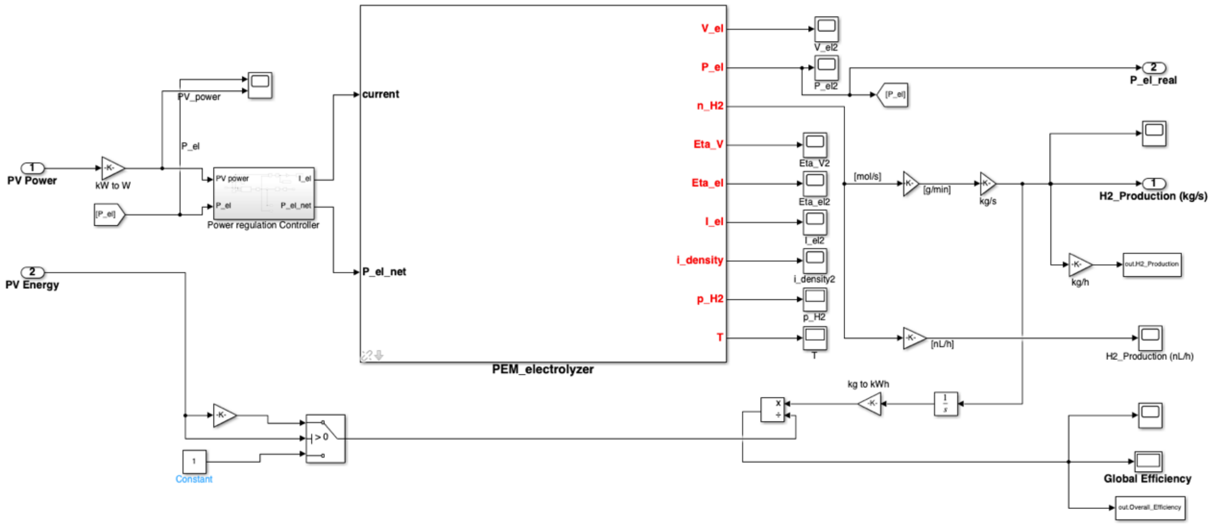


Figure 22. Simulink® model of the Electrolyzer Subsystem

The internal model of the PEM electrolyzer is structured to be customized from the user without the need to modify elements inside the main block (the central block in the picture above). Instead, from the block interface or from Matlab® script, the user can set different variables influencing the nominal power and the efficiency of the electrolyzer, such as the electrolyzer pressure and temperature, the stack number of cells, the width of the membrane, and other electrochemical parameters. Thus, the nominal power of the electrolyzer has been set equal to the nominal power of the PV plant, considering a power regulation range of 10÷100%. Infact, as noticeable from the scheme above, the electrolyzer production depends not only on the efficiency of the electrolyzer itself, but also on the power regulation constraints imposed. In the model, the “power regulation controller” positioned before the input section of the electrolyzer has the function to limit the incoming PV power to the power regulation span imposed. Thus, to calculate the global efficiency of the electrical energy conversion to hydrogen, some logical and algebraic operators perform the division between the overall chemical energy produced (hydrogen mass multiplied heating value) and the overall PV energy input.

5.3.3 Buffer Storage section

As briefly introduced in 4.2, the Buffer Storage Section has the function to decouple the electrolyzer activity from the compressor cycles schedule. The buffer storage chamber is a low-pressure stage which does not require hydrogen compression. Infact, this chamber can reach a maximum pressure equal to the maximum operational pressure of the electrolyzer (that for the PEMEL is about 30 bar), in absence of compressors. Consequently, the buffer chamber volume has been sized to reach the electrolyzer pressure of 30 bar when fully charged by the maximum daily hydrogen production during the operational year. That means that the most productive day of the year the buffer storage will reach its maximum pressure when fully charged, while all the other days the pressure will reach values below that threshold.

The gas lines have been modeled on Simscape®, considering the incoming Simulink® numerical signal (from the electrolyzer) and transforming it into a physical signal by means of a flow rate source coupled with a hydrogen reservoir, as shown in the picture below. The flow rate source has the function of imposing a certain mass flow rate to the hydrogen coming from the reservoir at a defined pressure, thus simulating the hydrogen flow rate from the electrolyzer. The buffer storage heat exchange with the environment has been modeled on Simscape® considering the chamber's internal convection, the conduction through the chamber's wall and the external convection. For the latter, an outdoor installation with a constant environment temperature of 15°C has been considered.

A picture of the Buffer Storage Subsystem is reported in the following picture:

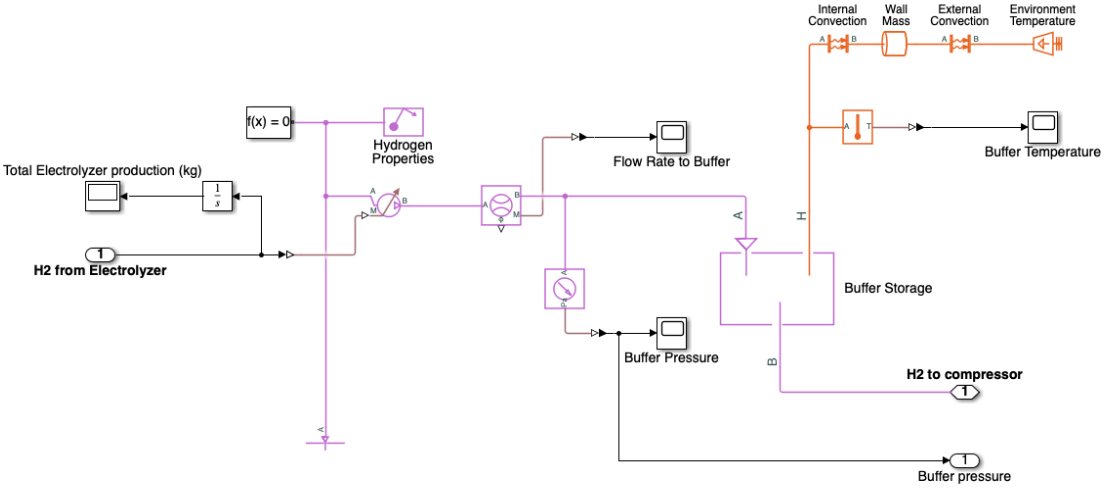


Figure 23. Simscape® model of the Buffer Storage Section

5.3.4 Long-term Storage Section

This section represents the seasonal storage for each scenario, with a large hydrogen storage capacity and consistent dimensions. The sizing procedure for this section starts after the calculation of both the hourly hydrogen production and the hourly hydrogen demand, which has been carried out during the PV plant sizing.

The difference between those vectors represents, for every time step considered, the storage status in terms of charge and discharge. Infact, if production exceeds consumption, the storage is found into a charging phase (this is what happens during summertime when the heating systems are turn off or when the demand is very low), and vice versa. So, the cumulative difference represents the overall status of the storage from the first day of operation (September 1st) until the time step considered, resulting in a positive value if the storage has been having a net gain in terms of hydrogen content, or in a negative value if the storage has been having a net decrease in hydrogen content.

Finally, by calculating the minimum value (a negative value) of this cumulative difference vector, the maximum long-term storage capacity is found, that means the capacity the storage must guarantee to compensate the winter discharge phase.

The real minimum capacity is higher than the value calculated above, since the lowest pressure reached by the long-term storage has to be higher than 1 bar and possibly similar to the buffer storage range (2-30 bar) for precautionary reasons.

As for the buffer storage section, also the long-term storage section has been modeled on Simscape®. The gas network that links the buffer storage the long-term storage is modeled considering a 20 meters pipe with perfect insulation and a tube diameter of 0,4 m. The mass flow to the compressors is maintained constant and it operating time is variable on the basis of pressure difference between the buffer storage and the compressors input node, which is considered at atmospheric pressure. A controlled gate valve, positioned after the pipeline, permits, or blocks the flow depending on the input signal received from the control logic (CS input).

The long-term storage heat exchange with the environment has been modeled considering the chamber's internal convection, the conduction through the chamber's wall and the external convection. For the latter, an outdoor installation with a constant environment temperature of 15°C has been considered.

Pictures of the Global Subsystem and the Compressor section are reported in the following.

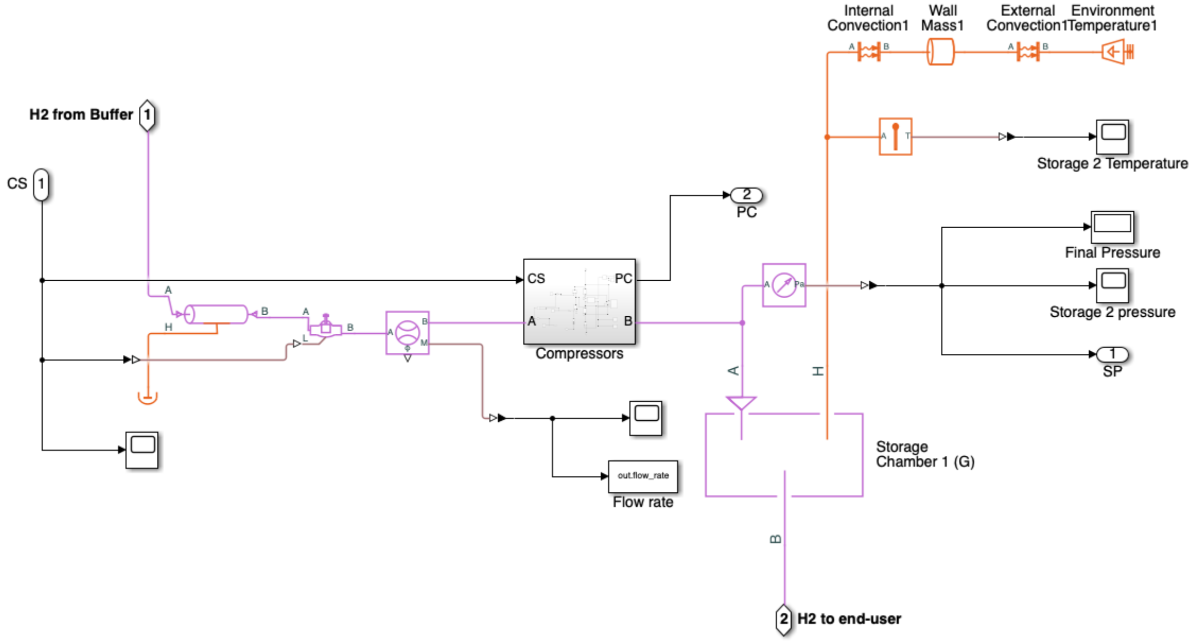


Figure 24. Simscape® model of the Long-term Storage Section

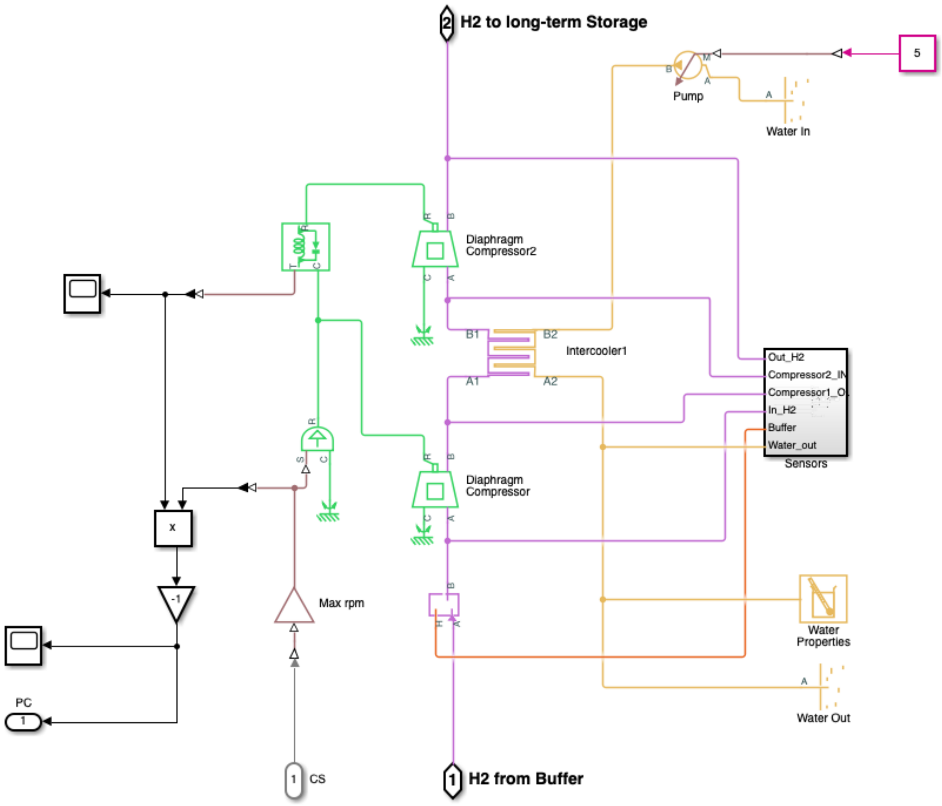


Figure 25. Simscape® model of the Compressors Section

The compression stage has been modeled on Simscape®, by means of two mono-axial positive displacement compressors (volumetric compressors). The hydrogen flow coming from the buffer storage enters a little constant volume chamber which has the function to reduce the stiffness of the gas network by increasing its total volume and sets the initial reference pressure of 1 bar at simulation time zero.

For each Scenario, compressors have been set with a nominal pressure ratio of 8:1, a nominal volumetric efficiency of 0.9, a nominal shaft speed of 450 rpm and a nominal flow rate depending on the buffer storage dimensions. More specifically, the nominal flow rate of the compressors has been calculated as the mass flow rate of hydrogen needed to discharge the buffer storage maximum capacity (reached during the most productive day) in five hours. Infact, to minimize electrical costs related to the compressors, a night-time activity from 12 am to 5 am has been considered. Compressors power (PC in the picture above) is calculated as the product of the torque times the angular velocity, on a hourly basis.

Between the two compression stages, a tube & shell heat exchanger has been placed, in order to reduce hydrogen temperature at the exit section of the first compressor. On the other hand, after the second stage of compression, no heat exchanger has been placed considering that hydrogen is flowing to the long-term storage located outdoor with a large volume at a constant temperature of 15°C.

On the right (see picture above) all the sensors have been grouped to a subsystem, with the aim of monitoring pressures and temperatures in all the different nodes (input node, stage 1 output node, stage 2 input node, output node).

For the duty of precision, it is important to remember that the model considers only two stages when in the real system at least 3 or 4 compression stages shall be required for hydrogen compression from 3~30 bar to 30~200 bar.

5.3.5 End-user Section

Finally, the end-user section has been modeled on Simscape®, as reported in the picture below.

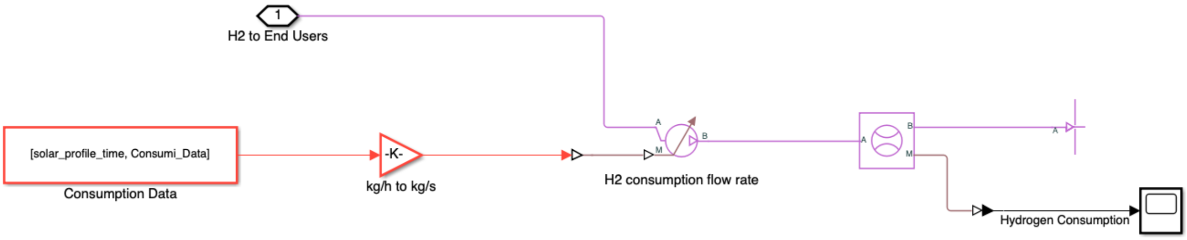


Figure 26. Simscape® model of the end-users section

As for the buffer storage-electrolyzer interface, the model of the end-user section includes a numerical Simulink® signal coupled with a Simscape® physical signal (the line in magenta in the picture above). The former represents the hydrogen consumption data on a hourly basis for each scenario, calculated as described in 4.3.1. The latter is the hydrogen flow coming from the long-term storage section, whose value is set equal to the relevant consumption data by means of the Flow Rate Source Simscape® element (see picture above).

Since the nature of the end-user section happens to be different for each scenario and its in-deep modeling is not relevant for the scope of this work, the hydrogen final output node has been set as a Reservoir element at atmospheric pressure and room temperature.

5.4 Control Logic

As briefly described before, the global model simulation requires a control logic to regulate the different phases of hydrogen production, storage and distribution.

The tool used to implement the control algorithm is Stateflow®, a Matlab® library tool that, within different features, can generate system states and state transitions. The transition from one state to another happens if the conditions imposed by the user are satisfied. Once a certain state is reached, the system can evolve in different directions depending on which condition is satisfied.

For the System, this control logic is used to regulate the phases of buffer charging and discharging by controlling the valves, together with the compressors switch on and switch off. In the following picture, the control logic implemented for the system is reported.

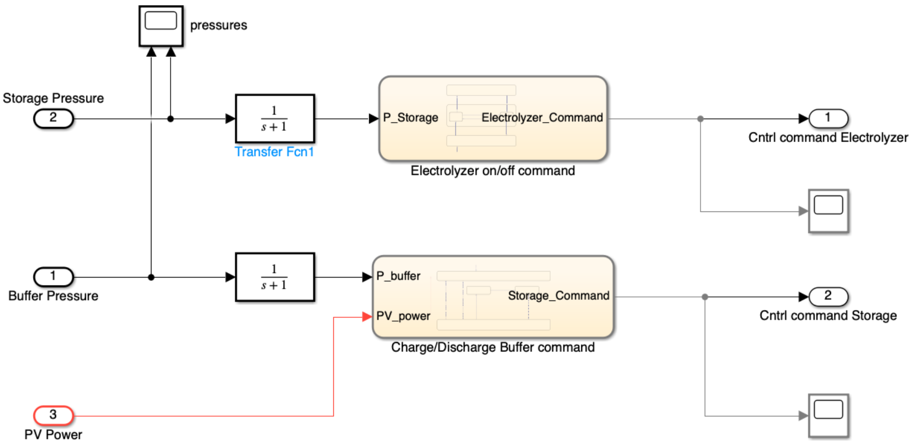


Figure 27. Global Control Logic Subsystem

The control system has three different input signals: the Buffer Storage and Long-term Storage pressure feedbacks, and the PV power signal. The output signals are the two control signals for the buffer charging and discharging ("Cntrl ommand Storage") and for the electrolyzer switch on/off ("Cntrl command Electrolyzer").

In the following picture the in-deep model of the control logic is reported.

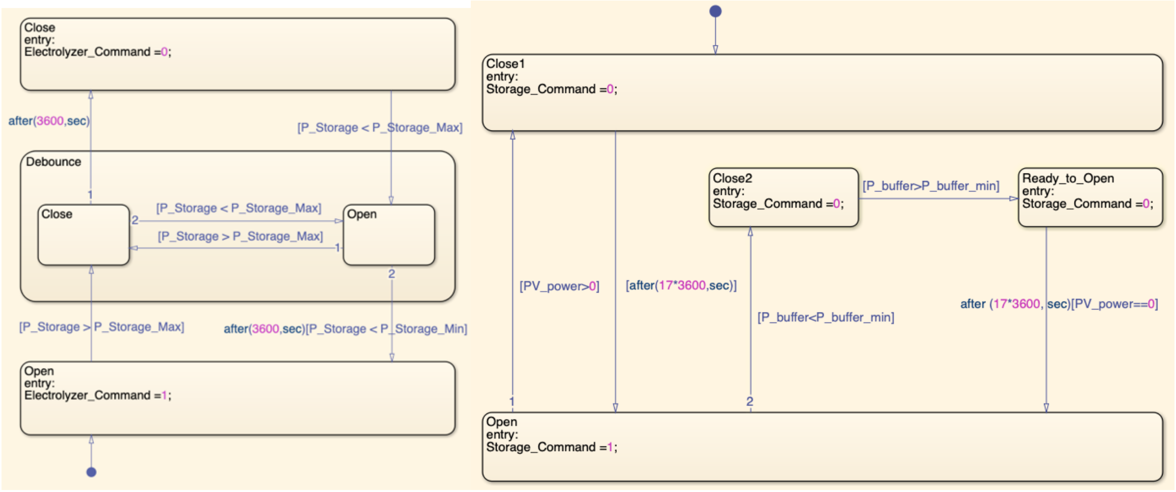


Figure 28. Stateflow® Control Logic for the Electrolyzer (left) and the Buffer Storage (right)

The control logic for the electrolyzer switch on/off is structured to cut off the input PV power to the electrolyzer and thus stop hydrogen production. This control is necessary to regulate the maximum capacity of the long-term storage, which could exceed its maximum pressure. Infact, even though it has been sized to reach 200 bar as pressure threshold, hydrogen production is highly variable depending on yearly weather conditions.

From the left picture above, it can be observed that if the pressure sensor located at the long-term storage reads a value of “P_Storage” higher than “P_Storage_Max” for at least an hour (3600 s), the state changes from “Open” to “Close” and the output control signal (CE) becomes a negative value (0) as an input to the “Electrolyzer Switch”, which cuts off PV power.

Then, if pressure drops below the maximum threshold (that has been set to 210 bar for all the scenarios) and keeps reducing below a minimum threshold (set to 199 bar) for at least an hour, the state changes again from “Close” to “Open”, and so on. The intermediate state called “Debounce” has been created to reduce fluctuations of pressure around the maximum pressure value, which generally happen due to transient state changes.

For what regards the Buffer Storage charge/discharge control system, represented on the right picture above, in this case there are more than two possible states, described in the following: the initial condition is “Close1”, and the output control signal (CS) is negative (0). It is remembered that the initial condition (starting time) for all the simulations has been set to September the 1°, 2019 at 05:00 am. During this state the electrolyzer is producing hydrogen and the Buffer Storage is charging. Then, after 17 hours, that means at the end of the day (at 22:00 pm), the System changes its state to “Open” and the output control signal becomes positive (1). This signal being positive turns into two different effects: (i) opening of the gate valve located after the Buffer Storage Section and (ii) compressors speed is set to the nominal value of 450 rpm (see pictures in 4.3.4). So, during this phase the Buffer Storage is discharging, and hydrogen is being compressed and sent to the long-term storage. If PV power turns positive (as soon as production is starting again) the Buffer discharge stops and the System changes its state again to the state “Close1”.

Another case is verified if the discharge is very rapid because the Buffer Storage was not charged completely during the day and thus reached a pression lower than 30 bar (during winter pressure often reaches 15⍰20 bar). In this case, the Discharge phase ends before PV production begins and the System changes its state from Open to “Close2”, if pressure drops below a minimum threshold called “P_buffer_min”, which has been set to 2 bar. Finally, the system changes again from “Ready to Open” to Open states when two contemporary conditions are verified: 17 hours have passed from the closing time and PV power is null, that means at the end of the day.

6 Analysis of Scenario n°1

The first scenario considered involves the construction of a hydrogen pipeline network to supply a portion of the residential boilers in the municipality of *Peio*, in the *Autonomous Province of Trento* in *Trentino-Alto Adige.*

6.1 Infrastructure Description

6.1.1 Site Location

The System, whose configuration will be described in detail in the next section, will be located inside an area including the municipality of Peio (TR) and the hamlet of Cogolo, and the municipality of Ossana (TR). Both municipalities are located within the Autonomous Province of Trento, at an altitude of 1585 m and 1000 m, respectively.

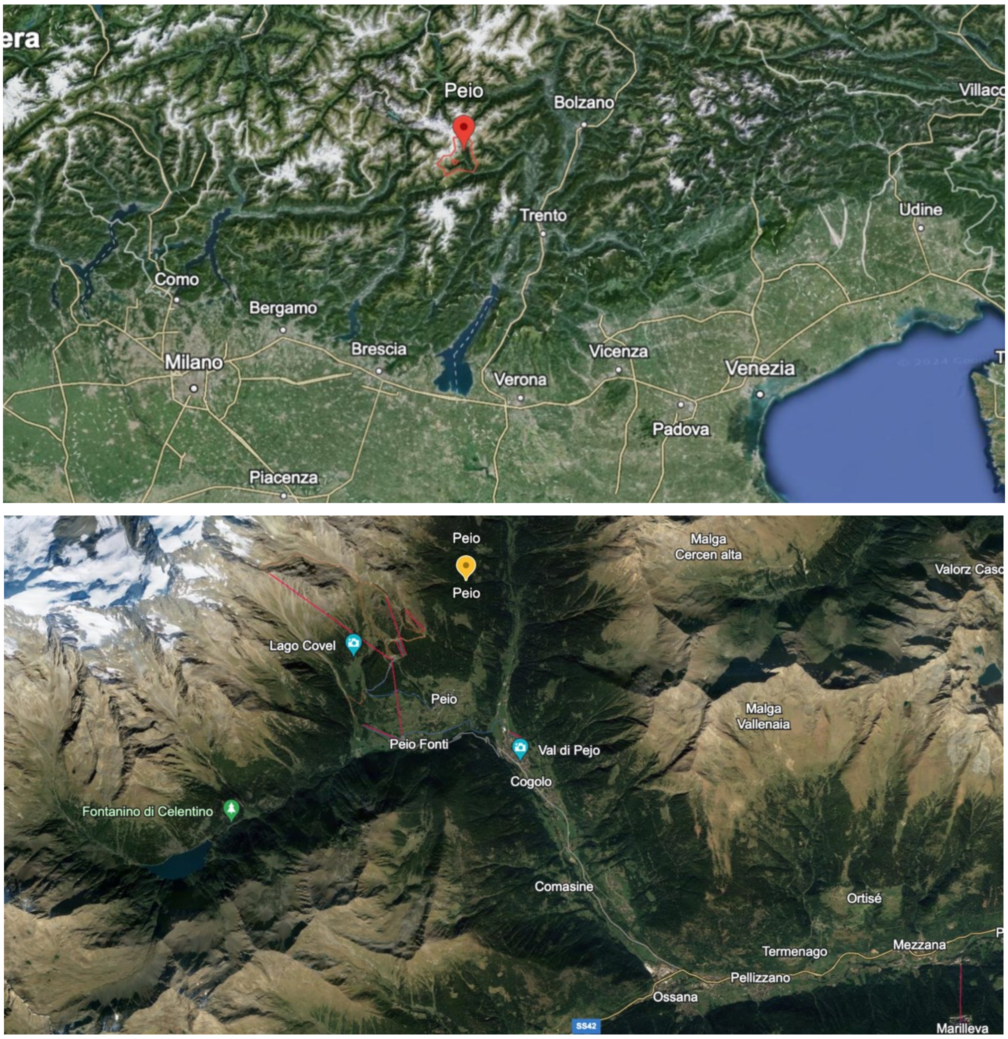


Figure 29. Scenario 1 – Site Location

6.1.2 Layout

The System includes five different macro-sections (PV plant, electrolyzer, buffer storage, long-term storage, and hydrogen pipeline) and will be developed on different areas, starting from the Municipality of Ossana to the Municipality of Peio In particular, the PV plant including all auxiliaries, the electrolyzer and the storage units will be installed in the location of Ossana, due to the greater availability of areas, fewer environmental constraints and better solar exposure (as well as more favorable climatic conditions). In the area adjacent to the PV plant, the electrolyzer and seasonal storage will be placed, due to electrical coupling necessities between the two sections of the system and for reducing the visual impact.

Instead, the hydrogen pipeline will be installed entirely in the municipality of Peio, more specifically in the municipal area called "Peio Alta," where residential heating systems currently consist mainly of pellet or oil-fired boilers. The hamlet of the municipality of Peio Cogolo is currently equipped with a district heating network fed by pellet burners, and therefore it is not considered prioritized to intervene with the modification of this network since the biomass resource is widely available in the area and does not present environmental criticalities.

The connection between the hydrogen production and storage area and the starting area of the hydrogen pipeline will be discontinuous, i.e., made through a land transportation system by means of tank cars (trailers), which will take a given amount of gas from the long-term storage unit and transport it to a short-term storage unit located at Peio Alta. The latter unit will have to guarantee a storage capacity equal to the gas requirements of one or two days of autonomy and will be characterized by a pressure compatible with the specifications of the pipelines that will make up the newly constructed hydrogen pipeline (typically in the range of 12~30 bar).

6.2 Sizing and Simulation parameters

6.2.1 Main parameters

The following main parameters have been adopted for the different sections of the System model, described in 3.3.

Scenario 1 - Peio	**Value**	**Unit**
Equivalent thermal power installed	11.50	MW
Hydrogen coverage factor	50%	%
Equivalent hours of operation	2708.33	h/year
LHV H_2	33.33	kWh/kg
	3.00	kWh/m^3
Electrolyzer specific consumption	51.28	kWh/kg
Electrolyzer efficiency	65%	%
Global efficiency	61%	%
Global specific consumption	54.64	kWh/kg

Table 14. Scenario n°1 – Main parameters

1 The equivalent thermal power installed has been calculated considering the sum of the residential boilers within the Municipality of Peio, including only the ones fed with fossil fuels (gasoil) and excluding the ones powered by biomass. However, this overall power installed is supposed to satisfy only the 50% of the total thermal demand (hydrogen coverage factor), since the remaining part will be satisfied by the already existing district heating network;

2 The number of equivalent hours of operation has been taken from the data available for the district heating network, supposing this value to be the same for residential heating boilers;

3 The values of electrolyzer specific consumption and electrolyzer efficiency have been taken from technical datasheets from currently available commercial units;

4 The global efficiency and so the global specific consumption have been calculated considering, together with the electrolyzer's efficiency and specific consumption, also the power loss due to power regulation constraints (electrolyzer is limited to 10÷100% nominal power).

6.2.2 Unit Parameters

In the following table, the values related to the thermal load and hydrogen demand are reported, together with the PV plant and Storage section specifications. It is remembered that the procedure that has been adopted to calculate these variables has been described in 4.3.

Demand		
Global thermal demand	15,573	MWh/year
H2 demand	5,190,972	Nm3/year
	466.7	ton/anno
PV plant		
PV plant producibility	1,200	kWh/kWp
Electrical demand	25,498	MWh/year
PV plant power	21.2	MWp
Storage		
Buffer capacity	2.506	ton
Buffer temperature	288.00	K
Buffer volume	1,000	m3
Storage capacity	209	ton
Storage temperature	288.00	K
Storage volume	12,507	m3

Table 15. Scenario n°1 – Unit parameters

In the following, the curve representing the calculated thermal power demand split on an hourly distribution for Scenario 1 is reported.

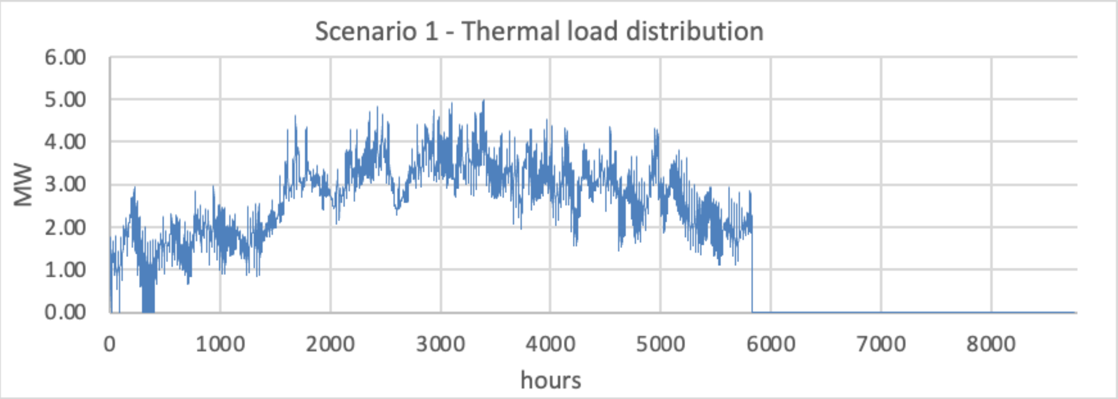


Figure 30. Scenario 1 – Thermal load distribution

As it can be seen from the graph above, for Scenario 1 the maximum thermal load reaches a peak of 5,00 MW during winter months, when the temperature difference between the indoor reference temperature and the outdoor temperatures is maximum.

The null values of the thermal load distribution begins after 5840 hours and ends after 8784 hours, which coincides with the period of heating boilers turn off (from April the 30° to August the 31°).

For what concerns the calculation of the long-term storage capacity, the curve representing the cumulative difference between hydrogen production and consumption is reported below.

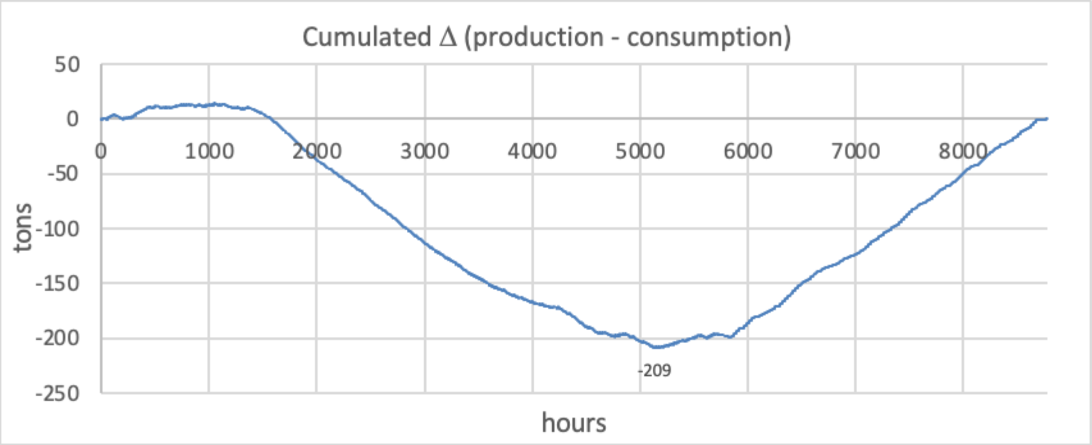


Figure 31. Scenario 1 – Cumulated difference between hydrogen production and consumption

From the figure above it is possible to understand how the long-term storage tank behaves during the year: in the first months of heating system operation (September and October), the curve is positive because production of hydrogen still exceeds consumption, meaning the long-term storage tank is being filled. Instead, from November to the end of March, the curve is decreasing with negative values and reaches a minimum of -209 tons, meaning the long-term storage tank is emptying. As described in 4.3.4, this value has been taken as the long-term storage capacity. The increasing part of the curve represents the period from March to August, when production exceeds consumption, and the storage is being charged again.

Finally, all the parameters adopted for each unit have been written to a Matlab® script, linked with the Simulink® file containing the global model of the system, in order to perform the simulation. The script for Scenario 1 is available in the attachments.

6.3 Simulation Results

The simulation results have been grouped into a subsystem called "Results" inside the global model of the system (see 3.2). The variables that better represent the system behavior during the simulation are:

- The PV power, the electrolyzer reference power and the electrolyzer real power for (i) the whole year and (ii) focused on the first 72 hours of operation, for a better understanding of the daily dynamics.
- The yearly pressure trends of the buffer storage and the long-term storage;

The plots of the above variables for Scenario 1 simulation are reported below.

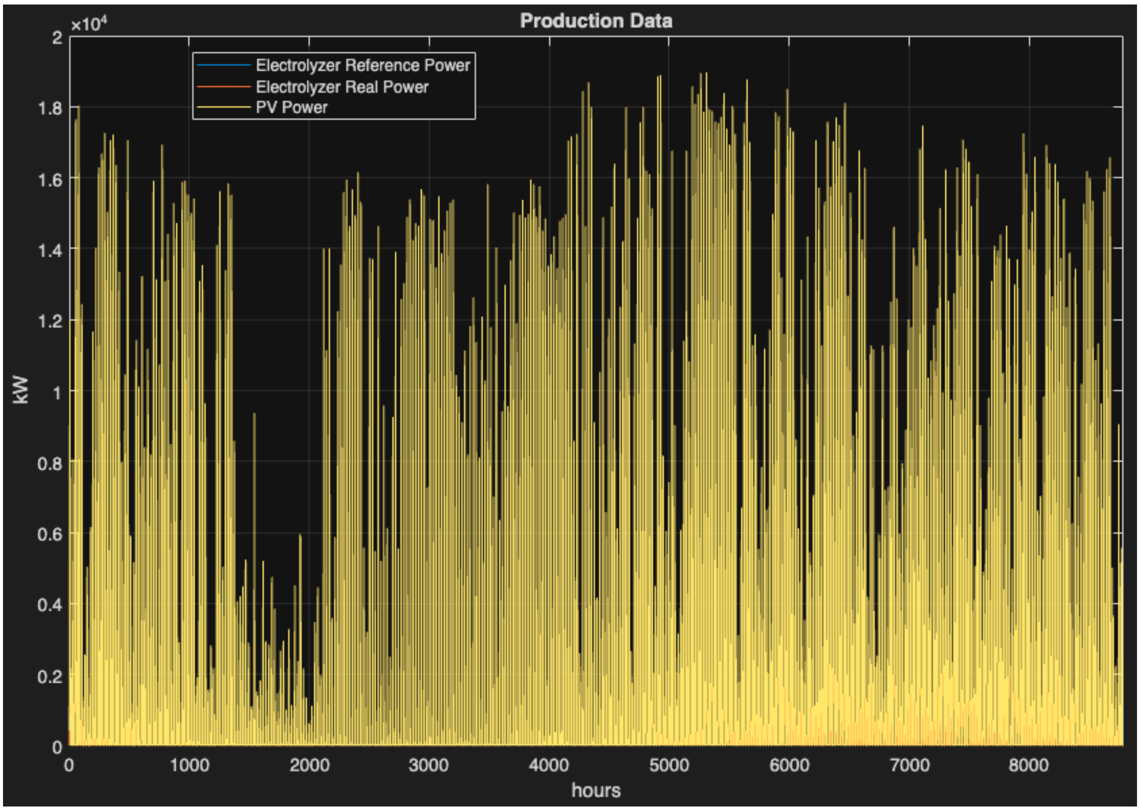


Figure 32. Scenario 1 – Yearly Production data

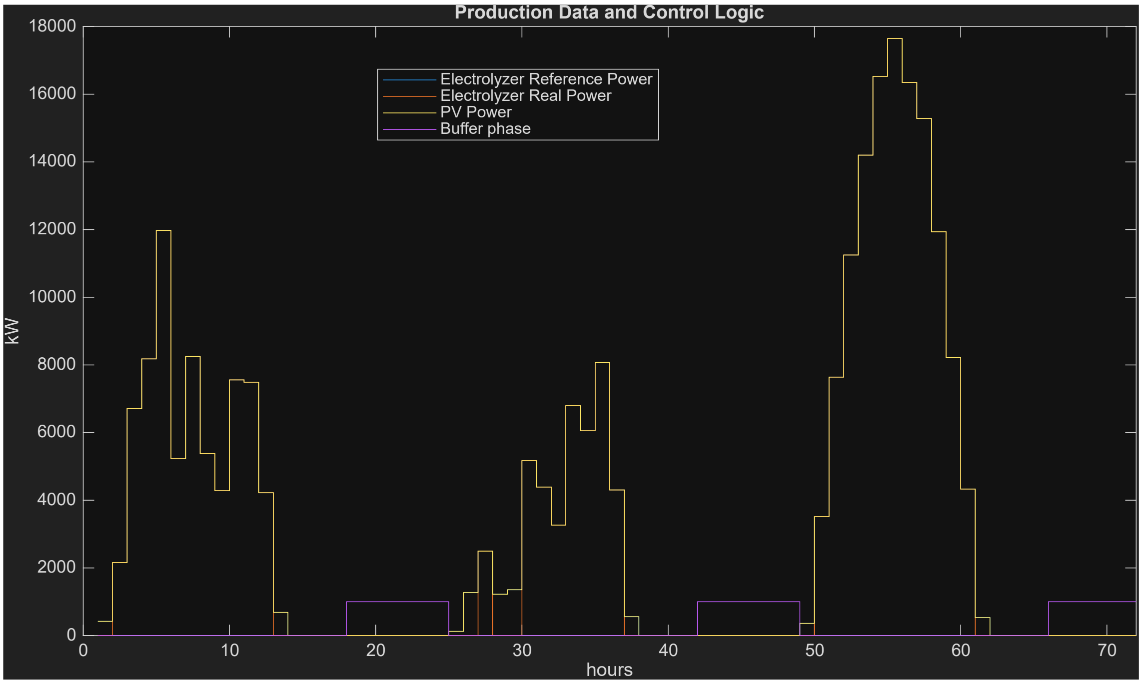


Figure 33. Scenario 1 – Production data and Control signal: buffer phase of charge (zero signal) and discharge (positive signal)

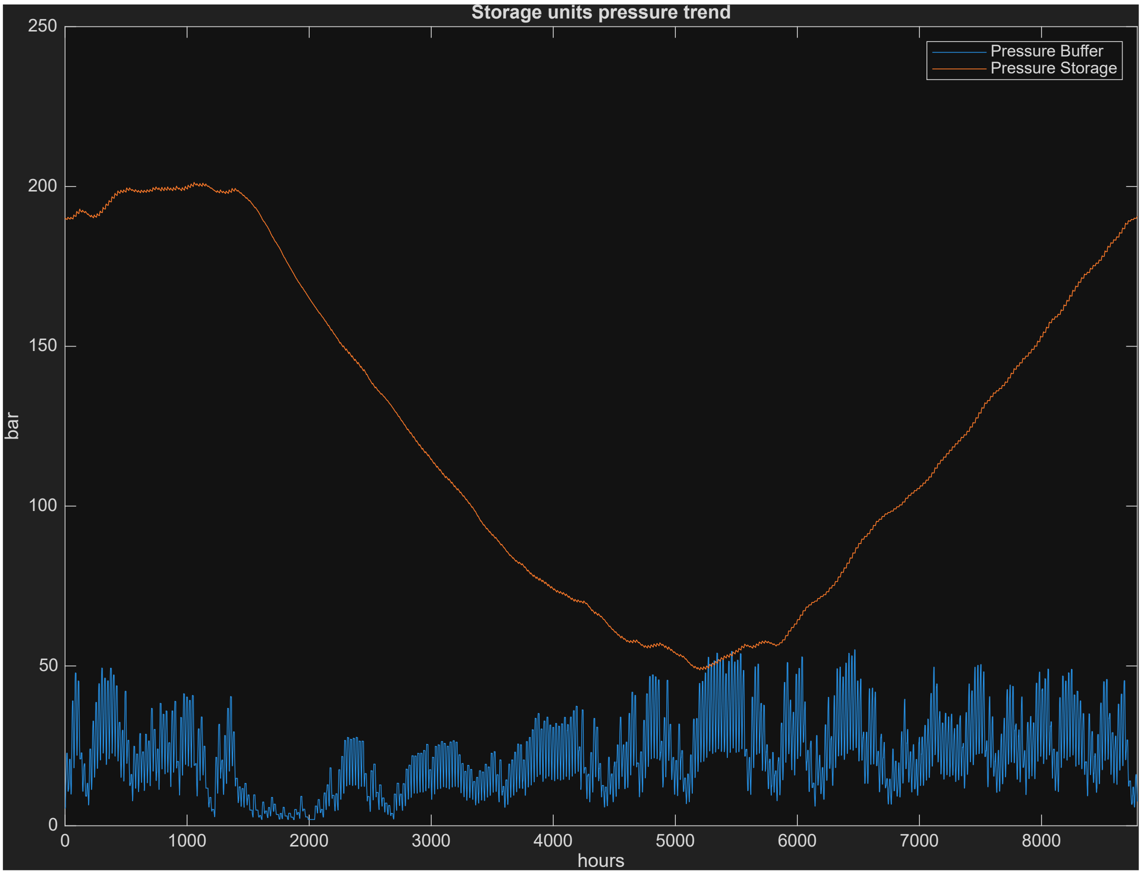


Figure 34. Scenario 1 – Pressure Trends

7 Analysis of Scenario n°2

The second scenario considered involves the integration of hydrogen into the existing gas network (blending) to supply the residential boilers in the municipality of *Ronzo - Chienis*, in the *Autonomous Province of Trento* in *Trentino-Alto Adige.*

7.1 Infrastructure Description

7.1.1 Site Location

The System, whose configuration will be described in detail in the next section, will be located inside an area including the municipality of Ronzo - Chienis (TR). The municipality is located within the Autonomous Province of Trento, at an of 1000 m.

Figure 35. Scenario 2 – Site Location

7.1.2 Layout

The plant includes five different macro-sections (photovoltaic plant, electrolyzer, buffer storage, long-term storage and mixing pipeline) and will be developed entirely on the municipal territory of Ronzo - Chienis. The preliminary layout of the plant is shown below.

The electrolyzer and seasonal storage will be located in the area adjacent to the PV plant, due to the need for electrical coupling between the two sections of the system and to reduce visual impact.

The connection between the long-term hydrogen storage and the gas network will be continuous, i.e., made by means of a mixing station that will take a certain amount of hydrogen from the long-term storage unit and inject it into the methane network. The latter unit will have to ensure a hydrogen injection pressure compatible with existing pipeline specifications (typically in the range of 12~ 30 bar).

7.2 Sizing and Simulation parameters

7.2.1 Main parameters

Two different cases have been taken into consideration for Scenario n°2, one with a volumetric percentage of hydrogen blended into the gas network equal to 10% (Scenario n°2a, and another one with 20% (Scenario n°2b).

The following main parameters have been adopted for the two cases for the different sections of the System model, described in 3.3.

Scenario n°2 – Ronzo - Chienis	**a**	**b**	**Unit**
Number of diffuse generators	565.00	565.00	-
Diffuse generators power	14.90	14.90	MW
Contemporaneity factor	40%	40%	%
Equivalent hours of operation	2708.33	2708.33	h/year
LHV H2	3.00	3.00	kWh/m3
LHV CH4	9.94	9.94	kWh/m3
Blending percentage	10.00%	20.00%	%volH2
LHV blended gas	9.25	8.55	kWh/m3
Electrolyzer specific consumption	54.64	54.64	kWh/kg
Electrolyzer efficiency	65%	65%	%
Global efficiency	61%	61%	%
Global specific consumption	54.64	54.64	kWh/kg

Table 16. Scenario n°2 – Main Parameters

1. The diffuse generators power is calculated as the sum of the residential boilers within the Municipality of Ronzo-Chienis. However, this overall power installed is supposed to have a contemporaneity factor of 40%, since the residential buildings hosting permanent residents within the municipality are globally less than 50% of the total buildings where the thermal power is installed. In addition to this, not all the thermal power is required at the same time from all the different structures, so the assumption above appears justified.

2. The number of equivalent hours of operation has been taken from the data available for the district heating network of Peio, supposing this value to be the same for residential heating boilers;

3. The values of electrolyzer specific consumption and electrolyzer efficiency have been taken from technical datasheets from currently available commercial units;

4. The global efficiency and so the global specific consumption have been calculated considering, together with the electrolyzer's efficiency and specific consumption, also the power loss due to power regulation constraints (electrolyzer is limited to 10~100% nominal power).

7.2.2 Unit parameters

In the following table, the values related to the thermal load and hydrogen demand are reported, together with the PV plant and Storage section specifications. It is remembered that the procedure that has been adopted to calculate these variables has been described in 3.3.

Demand	**a**	**b**	**unit**
Global thermal demand	15,942	15,942	MWh/year
Blended gas demand	1,724,186	1,864,105	Nm3/year
H2 demand	172,419	372,821	Nm3/year
	15.50	33.52	ton/year
PV plant	**a**	**b**	**unit**
PV plant producibility	1345	1345	kWh/kWp
Electrical demand	891.7	1849	MWh/year
PV plant power	0.63	1.36	MW

Storage	a	b	unit
Buffer capacity	73.60	163.4	kg
Buffer temperature	288	288	K
Buffer volume	40	65	m3
Storage capacity	6.5	14.1	ton
Storage temperature	288	288	K
Storage volume	550	1200	m3

Table 17. Scenario n°2 – Unit parameters

In the following, the curves representing the calculated thermal power demand split on an hourly distribution for Scenario 2-a and 2-b are reported.

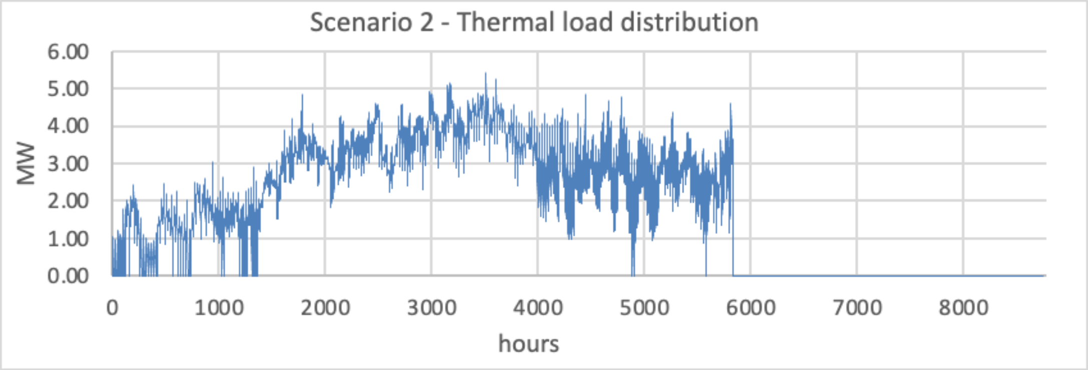


Figure 36. Scenario 2 – Thermal load distribution

As it can be seen from the graph above, for Scenario 2a and 2b the thermal load reaches a peak of about 5,4 MW during winter months, when the temperature difference between the indoor reference temperature and the outdoor temperatures is maximum. However, it is remembered that for Scenario 2 the thermal load distribution reported in the above picture is representative of the global thermal power required from the users, while the thermal power satisfied by hydrogen coincides only with the 10%/20% in volume of the required blend fuel, that means about 3,2%/7,00% of the total thermal power.

The thermal load distribution satisfied by hydrogen is reported below for both Scenario 2a and 2b.

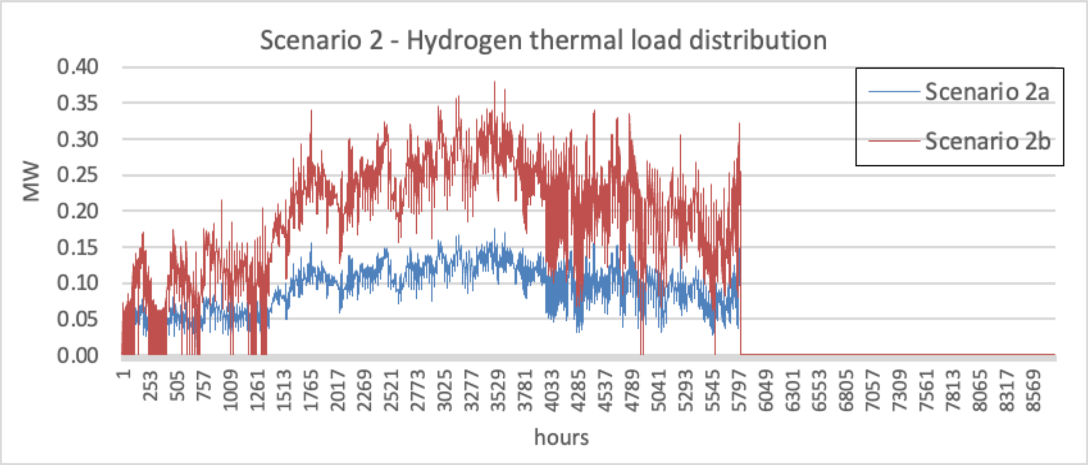


Figure 37. Scenario 2 – Hydrogen thermal load distribution

The null values of the thermal load distribution begins after 5840 hours and ends after 8784 hours, which coincides with the period of heating boilers turn off (from April the 30° to August the 31°).

For what concerns the calculation of the long-term storage capacity, the curve representing the cumulative difference between hydrogen production and consumption is reported below for both Scenario 2a and 2b.

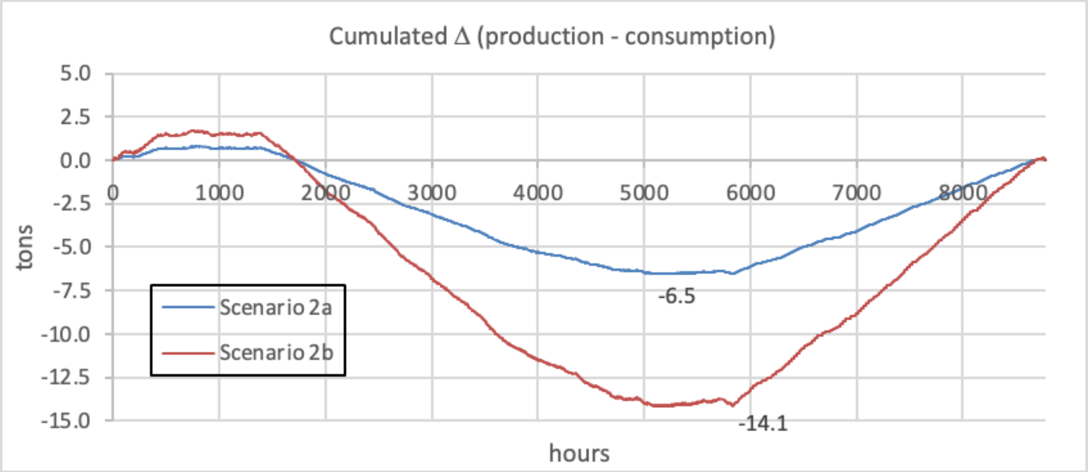


Figure 38. Scenario 2 – Cumulated difference between hydrogen production and consumption

From the figure above it is possible to understand how the long-term storage tank behaves during the year: in the first months of heating system operation (September and October), the curve is positive because production of hydrogen still exceeds consumption, meaning the long-term storage tank is being filled. Instead, from November to the end of March, the curve is decreasing with negative values and reaches a minimum of -6.5 tons and -14.1 respectively for Scenario 2a and 2b, meaning the long-term storage tank is emptying. As described, these values have been taken as the long-term storage capacity. The increasing part of the curve represents the period from March to August, when production exceeds consumption, and the storage is being charged again. It should be pointed out here that Scenario No. 2 (as well as No. 3) envisages a much smaller hydrogen requirement than in Scenario No. 1.

Finally, all the parameters adopted for each unit have been written to a Matlab script, linked with the Simulink file containing the global model of the system, in order to perform the simulation. The scripts for Scenarios 2a and 2b are available in the attachments.

7.3 Simulation Results

The simulation results have been grouped into a subsystem called “Results” inside the global model of the system (see 4.2). The variables that better represent the system behavior during the simulation are:

- The overall power produced;
- The yearly pressure trends of the buffer storage and the long-term storage;
- The yearly trend of the pressure in the compression section (inlet and outlet from the two storage systems)
- The PV power, the electrolyzer reference power and the electrolyzer real power for (i) the whole year and (ii) focused on the first 72 hours of operation, for a better understanding of the daily dynamics.

The plots of the above variables for Scenario 2a simulation are reported below. Scenario 2b plots are not reported since they are very similar to 2a, but with a higher power production.

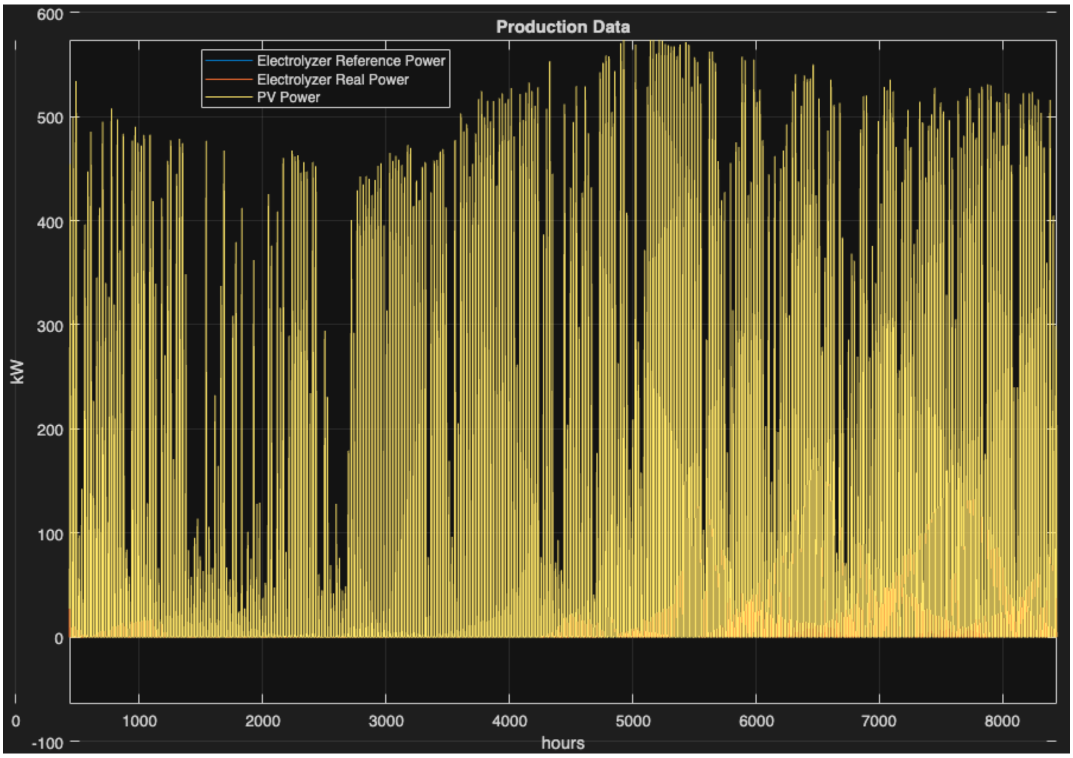


Figure 39. Scenario 2a – Yearly Production data

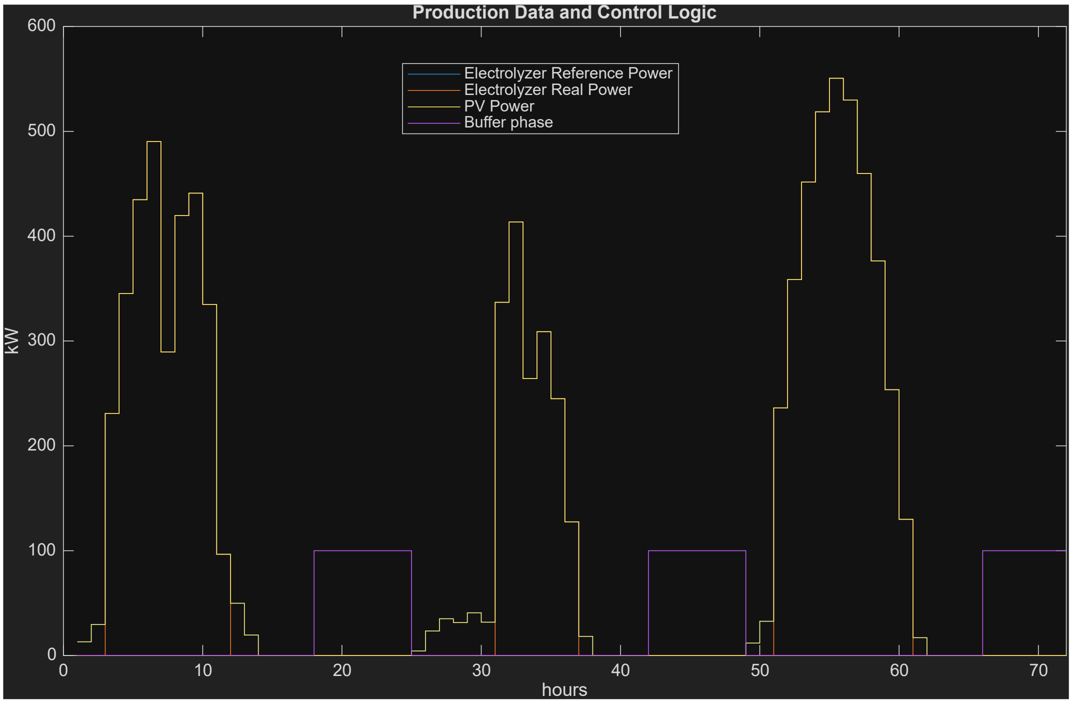


Figure 40. Scenario 2a – Production data and Control signal: buffer phase of charge (zero signal) and discharge (positive signal)

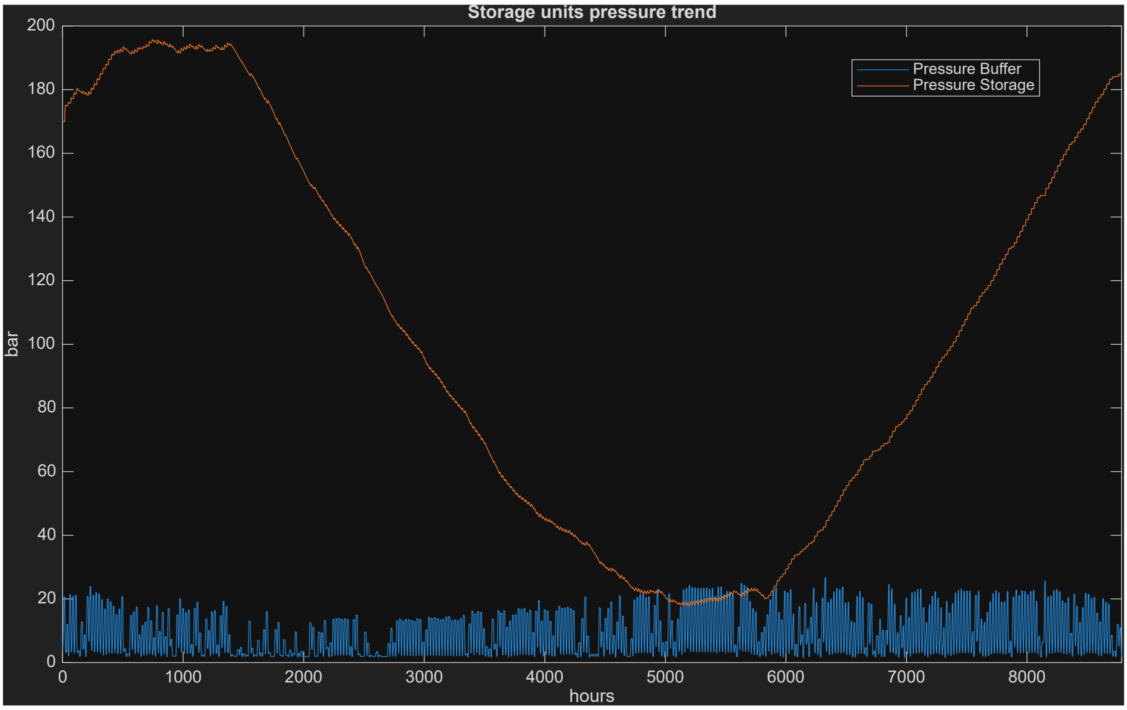


Figure 41. Scenario 2a – Pressure trends of buffer and long-term storage

8 Analysis of Scenario n° 3

The third scenario considered involves the substitution with hydrogen of diesel integration in the municipal district heating network for the municipalities of *San Martino di Castrozza* and *Fiera di Primiero*, in the *Autonomous Province of Trento* in *Trentino-Alto Adige.*

8.1 Infrastructure Description

8.1.1 Site Location

The System will be located inside an area including the municipalities of San Martino di Castrozza and Fiera di Primiero. The municipalities are both located within the Autonomous Province of Trento, at an altitude of 1487 m and 722 m, respectively. The aerial distance between the two towns is about 10 km.

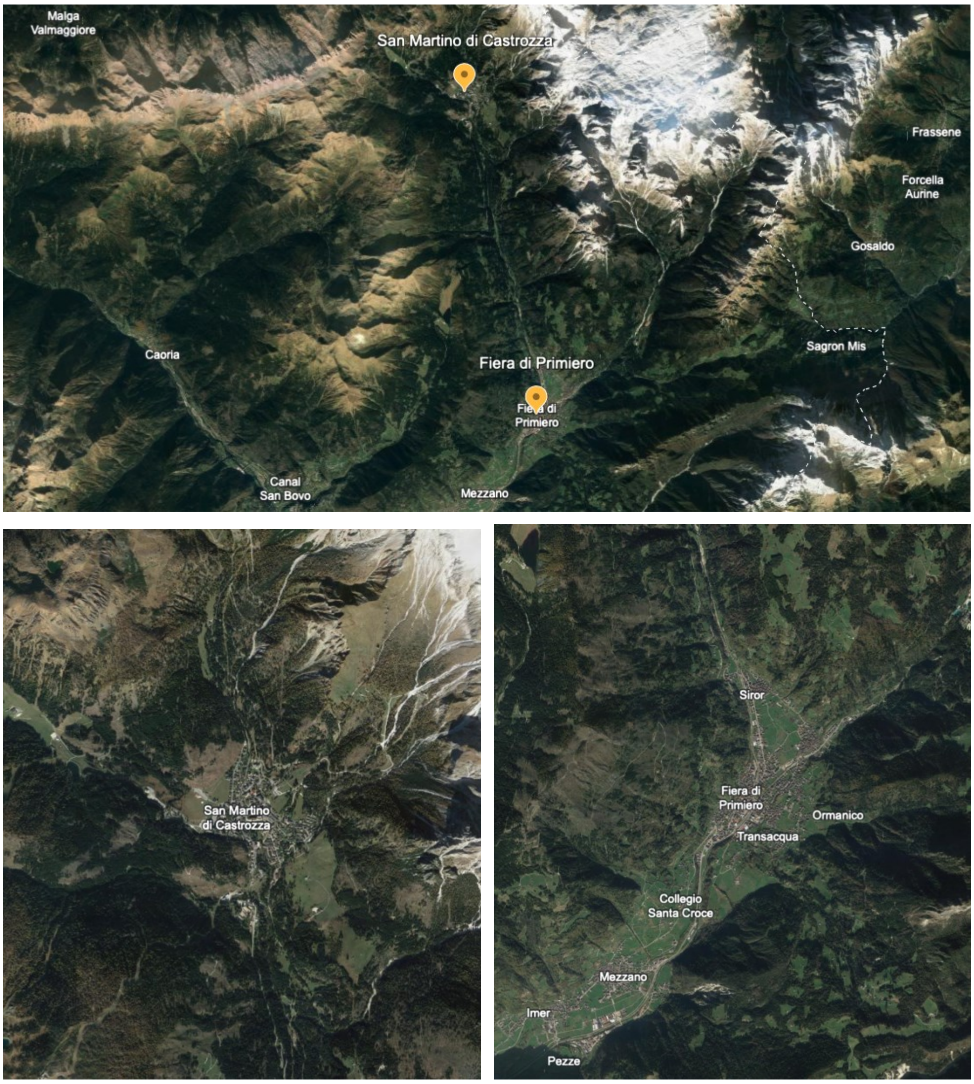


Figure 42. Scenario 3 – Site Location

8.1.2 Layout

The system includes five different macro-sections (photovoltaic system, electrolyzer, buffer storage, long-term storage, and district heating) and it will be developed in a suitable area within the two municipalities. The existing district heating network already meets the thermal needs of San Martino and Fiera di Primiero through the combustion of biomass (mainly pellets) with an integration of diesel to compensate for seasonal peaks. These peaks are concentrated in the winter period, particularly during the ski season from December to March. On the other hand, the municipality of Fiera di Primiero has a more distributed thermal demand, and its value is very similar to the amount of annual energy required by diesel supplementation in San Martino. For these considerations, the hydrogen generation plant should be located in a suitable area to supply the needs of both localities. The preliminary layout of the system is shown below.

The electrolyzer and seasonal storage will be located in the area adjacent to the PV plant, due to the need for electrical coupling between the two sections of the system and to reduce visual impact.

8.2 Sizing and Simulation parameters

8.2.1 Main parameters

The following main parameters have been adopted for the different sections of the System model.

Scenario 3 – San Martino & Fiera	Value	Unit
Equivalent thermal power installed	0.74	MW
Hydrogen coverage factor	100%	%
Equivalent hours of operation	2708.33	h/year
LHV H_2	33.33	kWh/kg
	3.00	kWh/m3
Electrolyzer specific consumption	51.28	kWh/kg
Electrolyzer efficiency	65%	%
Global efficiency	61%	%
Global specific consumption	54.64	kWh/kg

Table 18. Scenario n°3 – Main parameters

1. The equivalent thermal power installed has been calculated by dividing the thermal energy required from both municipalities in form of diesel oil by the equivalent hours of operation;
2. The hydrogen coverage factor is assumed to be 100% since the thermal energy supplied must match the total amount of energy supplied by diesel fuel;
3. The number of equivalent hours of operation has been taken from the data available for the district heating network, supposing this value to be the same of Scenario 1;
4. The values of electrolyzer specific consumption and electrolyzer efficiency have been taken from technical datasheets from currently available commercial units;
5. The global efficiency and so the global specific consumption have been calculated considering, together with the electrolyzer's efficiency and specific consumption, also the power loss due to power regulation constraints (electrolyzer is limited to 10�100% nominal power);

8.2.2 Unit parameters

In the following table, the values related to the thermal load and hydrogen demand are reported, together with the PV plant and Storage section specifications. It is remembered that the procedure that has been adopted to calculate these variables has been described in 3.3.

Demand		
Global thermal demand	2,000	MWh/year
H2 demand	666,7	Nm3/year
	60.0	ton/anno
PV plant		
PV plant producibility	1,300	kWh/kWp
Electrical demand	3,366	MWh/year
PV plant power	2.5	MWp
Stoccaggio		
Buffer capacity	0.298	ton
Buffer temperature	288	K
Buffer volume	145	m3
Storage capacity	25	ton
Storage temperature	288	K
Storage volume	1900	m3

Table 19. Scenario n°3 – Unit parameters

In the following, the curve representing the calculated hydrogen thermal power demand split on an hourly distribution for Scenario 3 is reported.

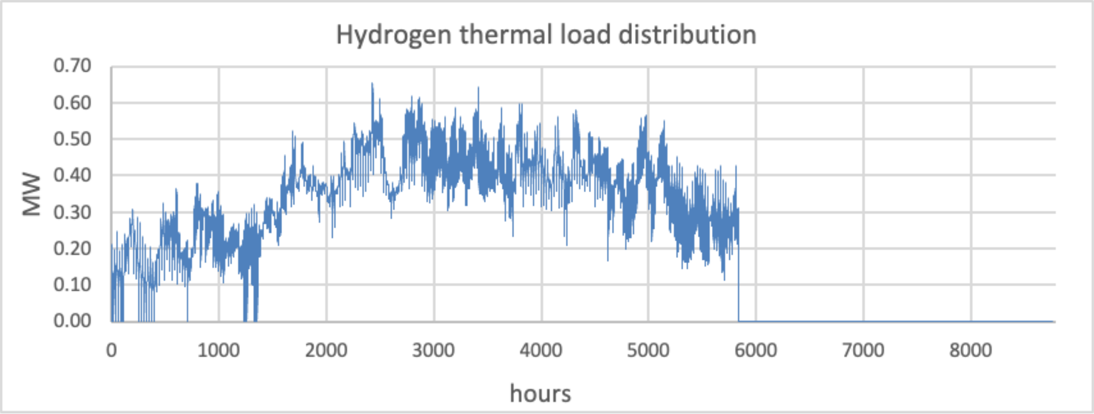


Figure 43. Scenario 3 – Hydrogen thermal load distribution

As it can be seen from the graph above, for Scenario 3 the maximum thermal load reaches a peak of 0,66 MW during winter months, when the temperature difference between the indoor reference temperature and the outdoor temperatures is maximum.

The null values of the thermal load distribution begin after 5840 hours and ends after 8784 hours, which coincides with the period of heating boilers turn off (from April the 30° to August the 31°).

For what concerns the calculation of the long-term storage capacity, the curve representing the cumulative difference between hydrogen production and consumption is reported below.

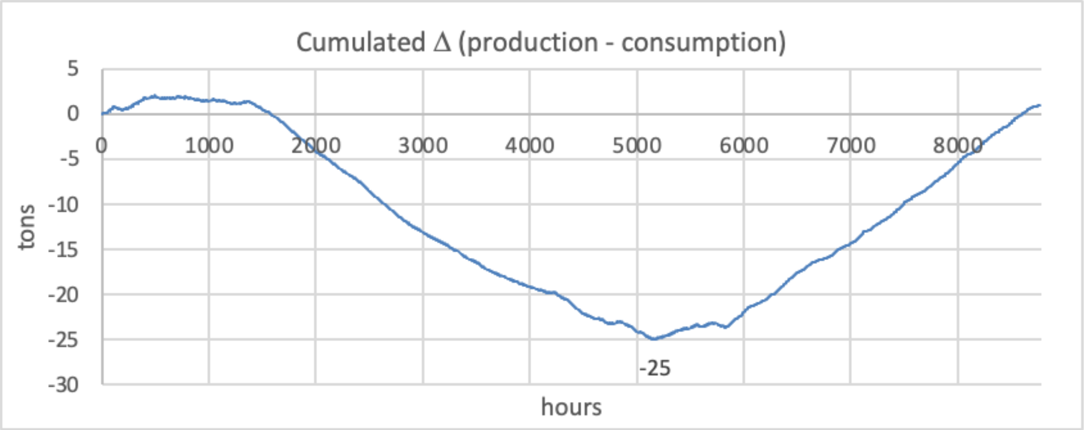


Figure 44. Scenario 3 – Cumulated difference between hydrogen production and consumption

From the figure above it is possible to understand how the long-term storage tank behaves during the year: in the first months of heating system operation (September and October), the curve is positive because production of hydrogen still exceeds consumption, meaning the long-term storage tank is being filled. Instead, from November to the end of March, the curve is decreasing with negative values and reaches a minimum of -25 tons, meaning the long-term storage tank is emptying. As already described, this value has been taken as the long-term storage capacity. The increasing part of the curve represents the period from March to August, when production exceeds consumption, and the storage is being charged again. The slightly positive value at 8784 hours (0.97 tons) means that the long-term storage has been slightly oversized to compensate the specific uncertainty on the value of thermal demand assumed (2,000 MWh).

Finally, all the parameters adopted for each unit have been written to a Matlab® script, linked with the Simulink® file containing the global model of the system, in order to perform the simulation. The script for Scenario 3 is available in the attachments.

8.3 Simulation results

The simulation results have been grouped into a subsystem called "Results" inside the global model of the system (see 4.2). The variables that better represent the system behavior during the simulation are:

- The overall power produced;
- The yearly pressure trends of the buffer storage and the long-term storage;
- The PV power, the electrolyzer reference power and the electrolyzer real power for (i) the whole year and (ii) focused on the first 72 hours of operation, for a better understanding of the daily dynamics.

The plots of the above variables for Scenario 3 simulation are reported below.

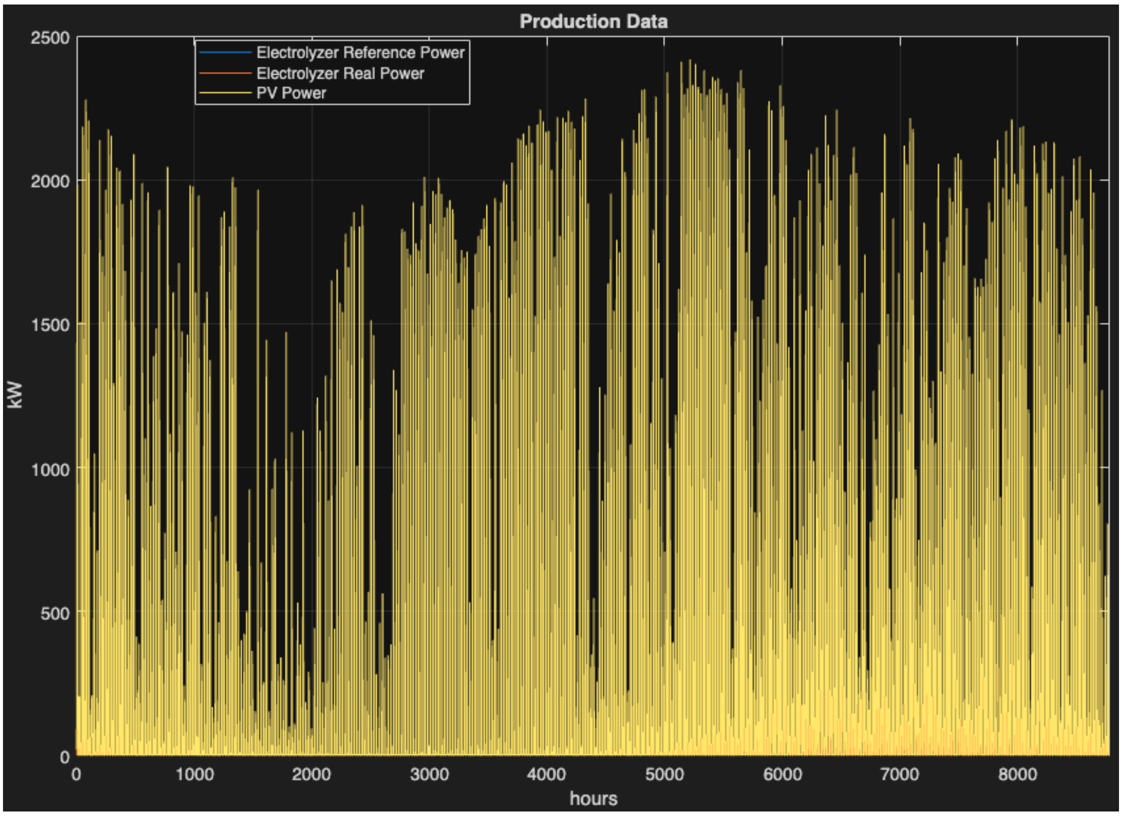


Figure 45. Scenario 3 – Yearly Production data

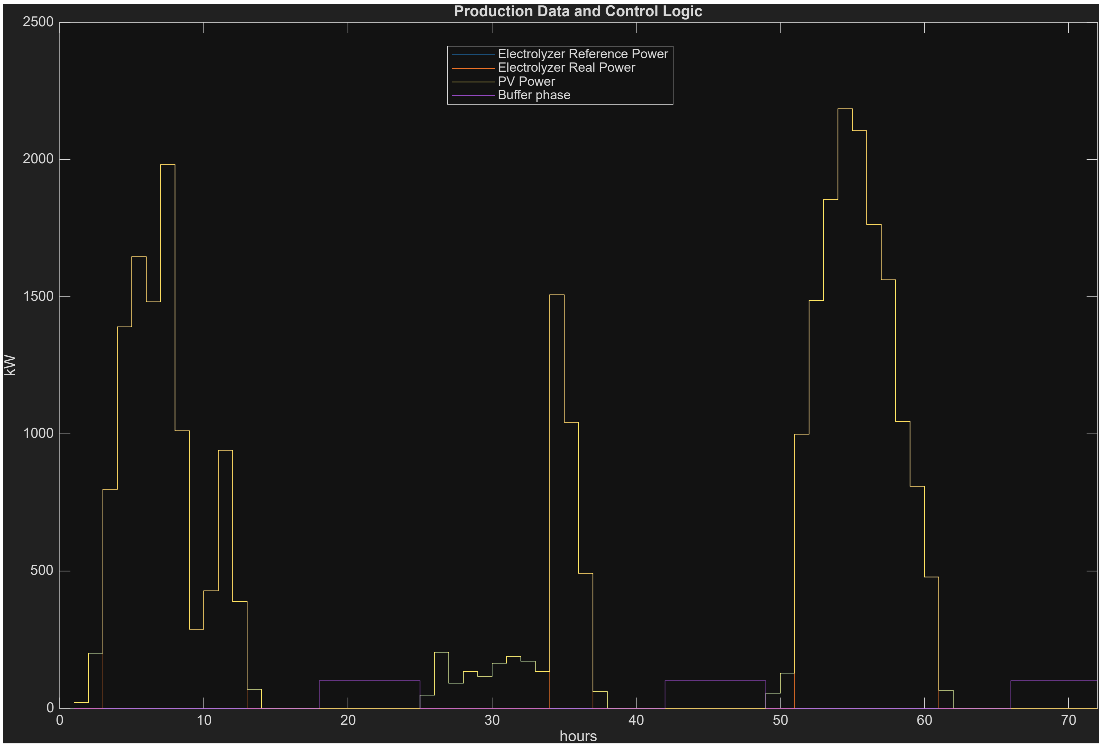


Figure 46. Scenario 3 – Production data and Control signal: buffer phase of charge (zero signal) and discharge (positive signal)

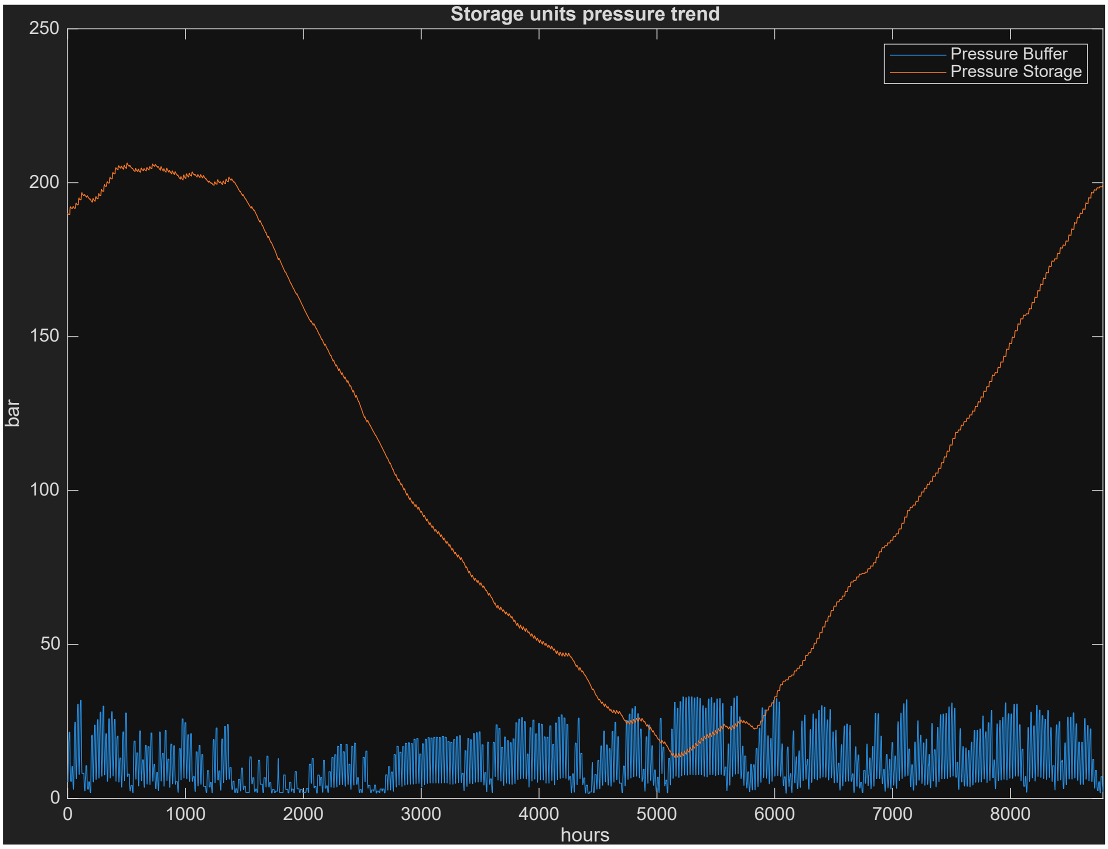


Figure 47. Scenario 3 - Pressure trends of buffer and long-term storage

9 Technical and Economic feasibility assessment of the project

This chapter will estimate plant costs broken down by macro-items including:

- PV Plant;
- Electrolyzer;
- Storage and Buffer system;
- Ancillary civil and plant works;
- H_2 distribution system.

9.1 Cost Assessment

The main equipment for which to determine costs are:

1) PV Plant

The cost estimate for an in-place PV system depends on the capacity and complexity of the installation. For a ground-mounted system, the estimated on-site cost varies between €900 and €1,100/kWp therefore €1,000/kWp is estimated as a reference value.
Below are the costs for the different Scenarios.

- Scenario 1 - Peio: 21,2 M€
- Scenario 2a - Ronzo Chenis: 0,63 M€ (10% blending)
- Scenario 2b - Ronzo Chenis: 1,36 M€ (20% blending)
- Scenario 3 - San Martino di Castrozza: 2,5 M€

2) Electrolyzer

In terms of estimating the cost of electrolyzers, as this is not a widely used technology, research was conducted on different sources and manufacturers to estimate the cost.
Below are the unit costs of electrolyzers and their source.

REF.	Ref. year	Size [MW]	CAPEX [€/kW]
https://www.eneaconsulting.com/static/3663dbb115f833de23e4c94c8fa399ec/enea-the-potential-of-power-to-gas.pdf	2016	0,5	2000
	2016	1	1500
	2016	10	1000
https://doi.org/10.1016/j.ijhydene.2018.07.164	2019	2	750
	2017	5	1100
https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/cost-forecast-for-low-temperature-electrolysis.pdf	2020	5	949
	2020	100	663
	2030	5	726
	2030	100	444
https://www.irena.org/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf	2020	>1	750-800 $/kW
https://assets.ey.com/content/dam/eysites/eycom/en_in/topics/energy/2023/02/ey-shortage-of-electrolyzers-for-green-hydrogen-v2.pdf?download	2023	-	700-1100 $/kW
https://www.iea.org/energy-system/low-emission-fuels/electrolysers	2023	-	500-1400
https://www.irena.org/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf	2020	-	770 $/kW
https://doi.org/10.1051/e3sconf/202233401001	2022	-	750

Table 20. Unit costs for electrolyzers

Based on the above table, a specific average cost value of 1,000 €/kW is assumed.
Below are the costs for the different Scenarios:

- Peio: 21,2 M€;
- Ronzo Chenis: 0,63 M€ (10% blending);
- Ronzo Chenis: 1,36 M€ (20% blending);
- San Martino di Castrozza: 2,5 M€.

3) Buffer

Buffer costs were estimated on a literature basis. The following parameters were taken into account to estimate a reliable cost:

- Standard cost of Hydrogen tanks;
- Pressure tanks from 15 to 250 bar;
- Complexity of installation.

Based on the above considerations, a specific tank cost evaluated in €/kg of stored hydrogen was estimated. This value is equal to 500 €/kg of H2.
Below are the costs for the 3 scenarios:

Scenario	**Buffer capacity (kg)**	**Buffer estimated cost (€)**
Scenario n°1	2500	250,000
Scenario n°2a	74	7,400
Scenario n°2b	163	16,300
Scenario n°3	298	29,800

Table 21. Buffer storage costs

4) Long-term storage system

The buffer cost estimate was estimated on a literature basis.

The following parameters were taken into account to estimate a reliable cost:

- Standard cost of Hydrogen tanks;
- Pressure tanks from 15 to 250 bar;

- Complexity of installation.

Based on the above considerations, a specific tank cost evaluated in €/kg of stored hydrogen was estimated. This value is equal to 500 €/kg of H2.
Below are the costs for the 3 scenarios:

Scenario	Storage capacity (kg)	Storage estimated cost (€)
Scenario n°1	209,000	20,900,000
Scenario n°2a	6,500	650,000
Scenario n°2b	14,100	1,410,000
Scenario n°3	25,000	2,500,000

Table 22. Long-term storage costs

5) Compression System

Different scenarios operate at different pressures and flow rates. Assessment of compressor costs should be evaluated for each system, with reference to the available depliant of the producers. On such basis, the costs are defined as follows.

- Scenario 1: 60.000 €
- Scenario 2 A: 10.000 €
- Scenario 2 B: 18.000 €
- Scenario 3: 20.000

6) Civil works and ancillary plant works

The estimation of costs related to civil works, not having available the identification of a defined site, it is possible to make it only on the basis of general evaluations and typology of similar plants by giving a percentage value with respect to the main plant works (Electrolyzer, storage system and compressor plant, PV plant).
The civil works to be performed for this type of plant are also estimated to involve (simplifying and not exhaustive list):

- Excavation and earth placement;
- Concrete foundations;;

- First rain collection system;
- Manufactures to be used as technical rooms,
- Electrical system (lighting and FM),
- Water system (water distribution and treatment);
- Compressed air system;
- Fire detection and protection system.

The above works are estimated to affect 10% of the cost of the facilities.

7) H_2 Transport works

Also for estimating the costs of the H2 transport and distribution system, reference was made to a specific value calculated as €/m of pipeline in place.

This value was calculated as follows, as dependent of the pipe diameter:

$$Invest\left[\frac{€}{m}\right] = \mathrm{Invest_A} * D^2 + \mathrm{Invest_B} * D + Invest_C$$

Parameter	Value	Unit
Pressure in	20	bar
Pressure out	2	bar
Invest. A	0.0022	€/mm^2
Invest. B	0.86	€/mm
Invest. C	247.5	€

Table 23. Parameters adopted for the hydrogen transport works cost estimation

The value for a 10" pipe is estimated at about €247.50/m. Below are the route lengths of the respective scenarios:

Scenario 1:	10.000 m – 2,48 M€
Scenario 2 A:	500 m – 0.12 M€
Scenario 2 B:	500 m – 0.12 M€
Scenario 3:	500 m – 0.12 M€

8) Total cost summary

The total costs for the different scenarios are reported in the table below:

Cost figure [M€]	Scenario n°1	Scenario n°2a	Scenario n°2b	Scenario n°3
PV Plant	21.2	0.63	1.36	2.5
Electrolyzer	21.2	0.63	1.36	2.5
Compressor	0.060	0.010	0.018	0.020
Buffer	0.25	0.007	0.016	0.030
Long-term storage	20.9	0.655	1.417	2.5
Transport works	2.48	0.12	0.12	0.12
Civil works and ancillary plant works	6.4	0.2	0.4	0.8
Total	**72.5**	**2.3**	**4.7**	**8.4**

9.2 Land occupation

Below a table containing the estimated average land occupation of the PV system for each scenario is reported.

Parameters	Unità	Scenario 1	Scenario 2a	Scenario 2b	Scenario 3
PV plant power	MW	21.0	0.6	1.4	2.5
Area required	ha	31.5	0.9	2.0	3.8
Average power per single user	kW	19.63	0.63	0.63	8.80
Area required per single user	m^2	294.39	16.73	36.11	132.04

9.3 Comparative analysis

9.3.1 CO2/MWh yearly comparison with fossil source

In order to assess the reduction of climate-changing gases, it is necessary to evaluate the emission values of CO2 equivalent for different fossil sources.

Below are the emission values, updated to 2022 of the main sources used for domestic heating (natural gas, LPG, Diesel, and electricity).

- Natural gas: 0,190 kgCO2eq./kW
- GPL: 0,170 kgCO2eq./kWh
- Diesel fuel: 0,228 kgCO2eq./kWh
- Electricity: 0,530 kgCO2eq./kWh

Parameters	**Unità**	**Scenario 1**	**Scenario 2a**	**Scenario 2b**	**Scenario 3**
Electricity produced	MWh/year	25,498	892	1,849	3,366
Thermal energy consumed	MWh/year	14,024	490	1,017	2,000
Natural gas emissions reduction	ton$CO_{2,eq}$/year	2,665	93	193	380
GPL emissions reduction	ton$CO_{2,eq}$/year	2,384	83	173	340
Diesel fuel emissions reduction	ton$CO_{2,eq}$/year	3,197	112	232	456
Electricity emissions reduction	ton$CO_{2,eq}$/year	7,433	260	539	1,060

Table 26. Estimation of equivalent CO_2 emissions reduction for each Scenario

For the scenarios considered, reference is made to thermal energy carriers only, so the savings in terms of CO2 equivalent can be evaluated with reference to the substitution of heating plants feeded with fossil sources.

9.3.2 Cost comparison €/MWh with fossil source

To calculate the cost of energy, we proceed by determining the energy produced during the useful life of the plant, which is estimated to be 20 years.
Therefore, for the 3 scenarios the specific cost of the produced energy is:

Parameters	**Unità**	**Scenario 1**	**Scenario 2a**	**Scenario 2b**	**Scenario 3**
Total costs	M€	72.5	2.3	4.7	8.4
Electricity yearly produced	MWh/anno	25,498	892	1,849	3,366
Thermal energy saved yearly	MWh/anno	14,024	490	1,017	2,000
Electricity produced during lifespan	MWh	509,960	17,834	36,980	67,320
Thermal energy saved during lifespan	MWh	280,478	9,808	20,339	40,000
Specific cost of energy production by H_2	**€/kWh$_{H2}$**	**0.258**	**0.230**	**0.231**	**0.211**

Table 27. Specific cost of electricity produced for each Scenario

10 Risk Analysis related to Project realization

The following analysis relates estimated system costs to a potential increase due to:

- Increased demand for PV systems and system equipment in general,
- Increase due to an assessment not adhering to future scenarios of system costs,
- Increase due to exogenous and unforeseeable factors.

The potential increase was estimated at the value of 20 %.
The comparison was conducted either by increasing all components by 20 percent or by increasing the individual cost item by 20 percent and assessing its impact on the total cost.

1) 20% Increase in PV cost

Sensitivity Analysis	Unit	Scenario 1	Scenario 2a	Scenario 2b	Scenario 3
PV cost	M€	25.44	0.76	1.63	3.00
Total costs	M€	76.73	2.38	4.97	8.93
Specific cost of energy production by H_2	€/kWh$_{H2}$	0.274	0.243	0.244	0.223
Percentual increase of costs/cost of energy production	%	+5.85%	+5.58%	+5.79%	+5.93%

Table 28. Sensitivity analysis for PV plant cost variability

2) 20% Increase in Electrolyzer cost

Sensitivity Analysis	Unit	Scenario 1	Scenario 2a	Scenario 2b	Scenario 3
Electrolyzer cost	M€	25.44	0.76	1.63	3.00
Total costs	M€	76.73	2.38	4.97	8.93
Specific cost of energy production by H_2	€/kWh$_{H2}$	0.274	0.243	0.244	0.223
Percentual increase of costs/cost of energy production	%	+5.85%	+5.58%	+5.79%	+5.93%

Table 29. Sensitivity analysis for electrolyzer cost variability

3) 20% Increase in Compressor cost

Sensitivity Analysis	Unit	Scenario 1	Scenario 2a	Scenario 2b	Scenario 3
Compressors cost	M€	25.44	0.76	1.63	3.00
Total costs	M€	72.50	2.25	4.71	8.44
Specific cost of energy production by H_2	€/kWh$_{H2}$	0.258	0.230	0.231	0.211
Percentual increase of costs/cost of energy production	%	+0.02%	+0.09%	+0.08%	+0.05%

Table 30. Sensitivity analysis for compressors cost variability

4) 20% Increase in Buffer storage cost

Sensitivity Analysis	Unit	Scenario 1	Scenario 2a	Scenario 2b	Scenario 3
Buffer storage cost	M€	0.30	0.01	0.02	0.04
Total costs	M€	72.54	2.25	4.71	8.44
Specific cost of energy production by H_2	€/kWh$_{H2}$	0.259	0.230	0.231	0.211
Percentual increase of costs/cost of energy production	%	+0.07%	+0.07%	+0.07%	+0.07%

Table 31. Sensitivity analysis for buffer storage cost variability

5) 20% Increase in Long-term storage cost

Sensitivity Analysis	Unit	Scenario 1	Scenario 2a	Scenario 2b	Scenario 3
Long-term storage cost	M€	25.08	0.79	1.70	3.00
Total costs	M€	76.67	2.38	4.99	8.93
Specific cost of energy production by H_2	€/kWh$_{H2}$	0.273	0.243	0.245	0.223
Percentual increase of costs/cost of energy production	%	+5.77%	+5.80%	+6.03%	+5.93%

Table 32. Sensitivity analysis for long-term storage cost variability

6) 20% Increase in H2 transport facilities cost

Sensitivity Analysis	**Unit**	**Scenario 1**	**Scenario 2a**	**Scenario 2b**	**Scenario 3**
H_2 transport cost	M€	2.97	0.15	0.15	0.15
Total costs	M€	72.99	2.27	4.73	8.46
Specific cost of energy production by H_2	€/kWh$_{H2}$	0.260	0.233	0.232	0.211
Percentual increase of costs/cost of energy production	%	+0.68%	+1.10%	+0.53%	+0.29%

Tabele 33. Sensitivity analysis for H_2 transport facilities cost variability

7) 20% Increase in Civil and Ancillary plant works cost

Sensitivity Analysis	**Unit**	**Scenario 1**	**Scenario 2a**	**Scenario 2b**	**Scenario 3**
Civil and ancillary plant works cost	M€	7.69	0.23	0.50	0.91
Total costs	M€	73.77	2.29	4.79	8.58
Specific cost of energy production by H_2	€/kWh$_{H2}$	0.263	0.234	0.235	0.215
Percentual increase of costs/cost of energy production	%	+1.77%	+1.71%	+1.75%	+1.80%

Table 34. Sensitivity analysis for civil and ancillary plant works cost variability

8) 20% Increase in Total costs

Finally, the following table shows the variation in total system costs if total costs increase by 20 percent.

Sensitivity Analysis	**Unit**	**Scenario 1**	**Scenario 2a**	**Scenario 2b**	**Scenario 3**
Total costs	M€	86.99	2.70	5.65	10.12
Specific cost of energy production by H_2	€/kWh$_{H2}$	**0.310**	**0.276**	**0.277**	**0.253**

Table 35. Sensitivity analysis total costs variability

From the analysis of the costs and risk associated with variability, it can be seen that the greatest impact is associated with the costs of the photovoltaic system, electrolyser and seasonal storage, so it will be necessary to assess their impact carefully. In more detail:

- Photovoltaic technology has reached a very advanced level of commercial development. Significant cost deviations are not to be expected, except for possible availability crises related to significant increases in demand or criticality in the supply system.

- Electrolyser technology is constantly evolving; there are production plants with capacities exceeding current demand. This makes it possible to imagine an availability and cost reduction trend, but represents a considerable risk factor due to the high cost of operating plants that are not exploited to their full capacity**. Probably the cost of electrolysers is the real risk factor of an investment in this sector today and requires particular attention when evaluating the offer.**

- The technology of pressure vessels up to 250 bar is well established and cost tensions that would lead to significant deviations cannot be imagined.

11 Estimation of environmental impacts in terms of reduction of pollutant and climate-altering emissions

The following aspects of environmental impacts were considered to assess the environmental impacts:

1. **Land consumption:** an estimate of land consumption associated with the installation of PV systems was reported in Section 9.2. Specific parameters such as specific area per user were also evaluated. Among the various scenarios, scenario 1 is particularly impactful;

2. **Emissions reduction**: the use of PV as a renewable source avoids emissions of climate-altering gases. In Section 9.3.1, the amount of CO2 equivalent avoided was estimated.

3. **Water consumption**: water use is related to H2 production. A maximum of (Scenario 1 - Peio) 209 t of H2 was estimated to be produced annually, this amount will be produced with an amount of water equal to about 1,900 m3 of water which is equivalent to 5 m3 daily. This value does not generate a risk factor.

12 Analysis of the replicability and scalability conditions of the pilot project on the territory of Trentino and the Alps

On the basis of the results obtained in the study, it is possible to draw considerations on the scenarios adopted also because of their replicability on similar territories.

As far as the use of the photovoltaic resource is concerned, the fulfilment of request of thermal users can only be considered partial, especially considering the mismatch between increased solar availability and thermal needs. However, its use is useful if the electricity is used to power a hydrogen production plant intended as seasonal energy storage. In this context, it is useful to consider that:

- The possibility of envisaging PV plants should be evaluated in relation to the landscape impact that such plants could have in particularly valuable ree.
- The infrastructures to be considered should be as low-impact as possible.

- Plants that completely satisfy thermal needs require large investments that are not always available to small communities.

On the basis of what defined on the Scenario Analysis section considerations, the above considerations lead to the identification of Scenario n°2 and Scenario n°3 as feasible solutions.

Scenario 1, due to high investment, the scale of the requested feeding, and "land consumption," is to be considered unfeasible.

Then, to determine the replicability conditions of using renewable sources for small municipalities on the Alpine territory, the following operational conditions should be referred to:

a) Use of this solution to serve a district heating system to maximise plant efficiency;

b) Availability of local Natural Gas distribution lines within which to inject hydrogen in blending;

c) Application of hydrogen distribution systems to very small and concentrated users in very dense areas, with limited overall hydrogen demand and reduced distribution lines. It should be borne in mind, however, that in cases such as these, the choice of using a hydrogen-fuelled district heating system as in a) is still a more convenient alternative.

Analysis of Scenario n°4

Based on the results from the study regarding the production of hydrogen for thermal consumers in three types of mountain municipalities, the criticality related to the installation of large-scale PV systems and their associated electrolyzers emerged. The analysis showed an important mismatch between PV energy availability and energy demand; H2 storage volume values also increase under such conditions.

Through in-depth investigations on the ground, the possibility of exploiting the hydropower resource for the production of Green Hydrogen emerged.

Among the different possibilities analyzed in the first phase of the work, scenario 3 turns out to be the most suitable for the use of the H2 vector. The fourth scenario considered, therefore, involves the use of hydropower for the production of green hydrogen, with reference to the thermal needs of Scenario No. 3 for the localities of San Martino di Castrozza and Fiera di Primiero, in the Autonomous Province of Trento in Trentino-Alto Adige. Three different system configurations for hydrogen production were analyzed, named respectively: Scenario 4a, 4b and 4c.

Scenarios 4a and 4b involve the use of hydropower alone from the San Silvestro run-of-river hydroelectric power plant, part of the Primiero Energia group, and located in the municipality of Imer, in the Province of Trento. Scenario 4c involves electricity production from both hydroelectric and photovoltaic sources.

The hydroelectric power plant consists of a free-stream tunnel with a length of 11200 m and a maximum flow rate of 8 m3/s. The penstock connecting the pipeline to the power plant has a length of 525 meters and a diameter of 2.25 m, for a gross water head of 306 meters.

Three units consisting of:

- o a vertical axis, four-jet Pelton turbine of 8500 kW; 500 g/m', D.P.E.W. brand;
- o a synchronous alternator with power of 10,000 kVA and output voltage 9 kV, Ansaldo brand;

Overall, the plant develops an efficient power of 19 MW and an average annual producibility of about 120 GWh.

1.1 Site Location

Refer to section 8.1.1.

1.2 Layout

The system includes five different macro-sections (photovoltaic/hydroelectric plant, electrolyzer, buffer, long-term storage, and district heating network) and will be developed in a suitable area within the two municipalities. The existing district heating network meets the thermal needs of San Martino Di Castrozza and Fiera di Primiero through the combustion of biomass (mainly pellets), with an integration of diesel to compensate for seasonal peaks. These peaks are concentrated in the winter period, particularly during the ski season from December to March. On the other hand, the municipality of Fiera di Primiero has a more distributed thermal demand, and its value is very similar to the amount of annual energy required by the San Martino diesel supplementation system. For these considerations, the hydrogen generation plant should be located in a suitable area to supply the needs of both localities.

1.2.1 Scenario 4a

Scenario 4a envisions the use of hydropower from the above power plant, provided that the single national energy selling price (PUN), whose forecast for the year 2024 was derived from its trend in previous years, is lower than a certain threshold, chosen as a reference for the convenience of self-consumption of energy compared to sale to the grid. Given the significantly higher producibility of the power plant compared to the required demand for the considered scenario, self-consumption of electricity from the power plant represents only a small percentage of the total hydropower production (⍰ 10%). However, the high discontinuity of hydropower production makes it necessary to install a larger size electrolyzer, which is capable of operating at full power whenever there is hydropower production at PUN values below the set threshold, with a reduced number of annual operating hours.

1.2.2 Scenario 4b

Scenario 4b envisages the use of hydropower from the above power plant, with no PUN limitation, thus requiring self-consumption of a certain percentage of hydropower whenever there is production. The electrolyzer will have to operate at rated power for more hours per year than in Scenario 4a, but with reduced rated power.

1.2.3 Scenario 4c

Scenario 4c involves the combined use of hydropower from the San Silvestro power plant and a photovoltaic plant (newly built) sized according to the percentage of power drawn from the hydropower plant. Hydropower will be withdrawn under the condition that the single national energy selling price (PUN) is below a certain threshold, which was chosen as a reference for the convenience of self-consumption of hydropower compared to sale to the grid. Due to the abundant availability of hydropower at certain times of the year, the share of energy from the hydropower plant has been chosen to be favored over the share of energy produced by PV, which thus plays a supplementary role compared to the hydropower plant, in order to meet the required demand. Accordingly, the size of the electrolyzer was sized according to the nominal hydroelectric power drawn from the power plant. In this scenario, the percentage of power drawn from the hydropower plant will be slightly variable during the year due to the overlap of photovoltaic production with hydropower production. In fact, less hydropower will need to be withdrawn during peak PV production, having to limit the total power to the nominal power of the chosen electrolyzer.

The next section details the sizing parameters for scenarios 4a, 4b and 4c.

1.3 Sizing and Simulation Parameters

1.3.1 Main parameters

The main parameters for Scenario 4 are unchanged from those considered in Scenario 3, given in Section 8.2.1.

1.3.2 Unit parameters

The table below shows the values for thermal load and hydrogen demand, together with the specifications for the hydroelectric plant and the photovoltaic plant, as well as those for the storage section. Please note that the procedure adopted for calculating these parameters has been described in Section 5.3, and 13.1.2.

Parameter		Scenario 4a	Scenario 4b	Scenario 4c	Unit
Demand	Overall thermal demand	2,000	2,000	2,000	MWh/year
	H_2 Demand	60.0	60.0	60.0	ton/year
Hydro	PUN Threshold	70.0	-	70.0	€/MWh
	Percentage of power drawn	9.1	3.6	6.0	%
	Maximum power available	1.81	0.72	1.20	MW
	Power available	3.379	3.379	2.228	GWh/year
	Partition percent. Hydro/PV	-	-	62:38	-
PV Plant	PV Producibility	1,300	1,300	1,300	kWh/kWp
	Power available	-	-	1.350	GWh/year
	PV plant power	-	-	0.95	MWp
Electrolyser	Rated power	1.70	0.70	1.13	MW
	Equivalent hours	2000	4800	3000	h
Storage	Buffer capacity	200	200	200	kg
	Buffer temperature	288	288	288	K
	Buffer volume	81	81	81	m^3
	Storage capacity	26.66	25.47	21.59	ton
	Storage temperature	288	288	288	K
	Storage volume	1900	1800	1600	m3

Table 1. Scenario n°4 – Unit parameters

Below is the curve representing the calculated hydrogen thermal energy demand divided over an hourly distribution for Scenario 4 (similar to Scenario 3).

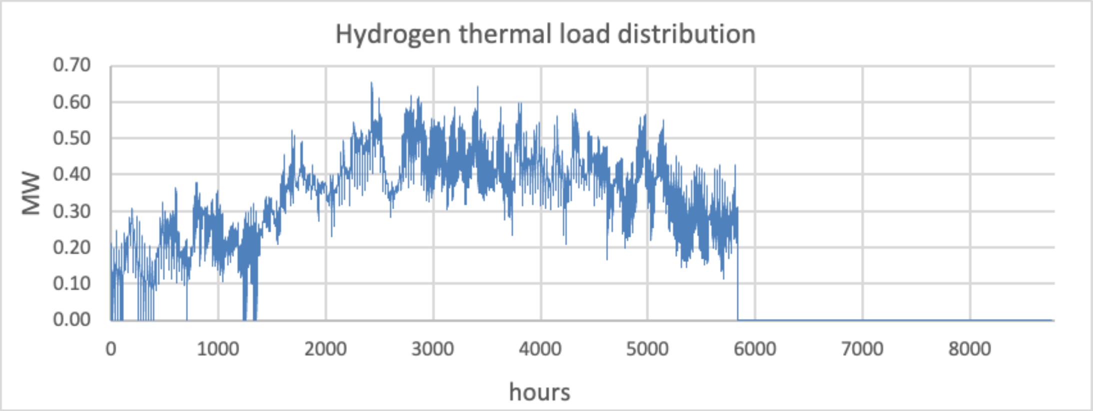


Figure 1. Scenario 4 - Hydrogen thermal load distribution.

As can be seen from the above graph, for Scenario 4, the maximum heat load peaks at 0.66 MW during the winter months, when the difference between the reference indoor temperature and outdoor temperatures is greatest.

The null values of the heat load distribution begin after 5840 hours and end after 8784 hours, which coincides with the period when the heating boilers are turned off (April 30° to August 31°).

Regarding the calculation of long-term storage capacity, the curves representing the cumulative difference between hydrogen production and consumption are shown below.

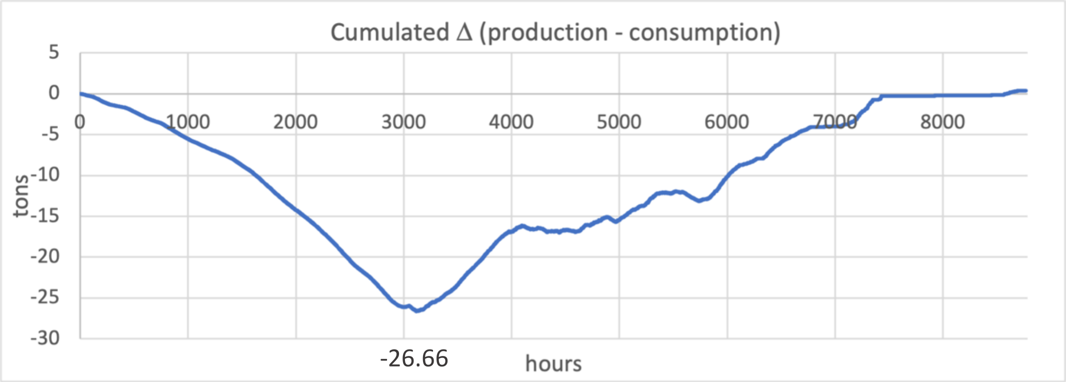


Figure 2. Scenario 4a - Cumulative difference between hydrogen production and consumption

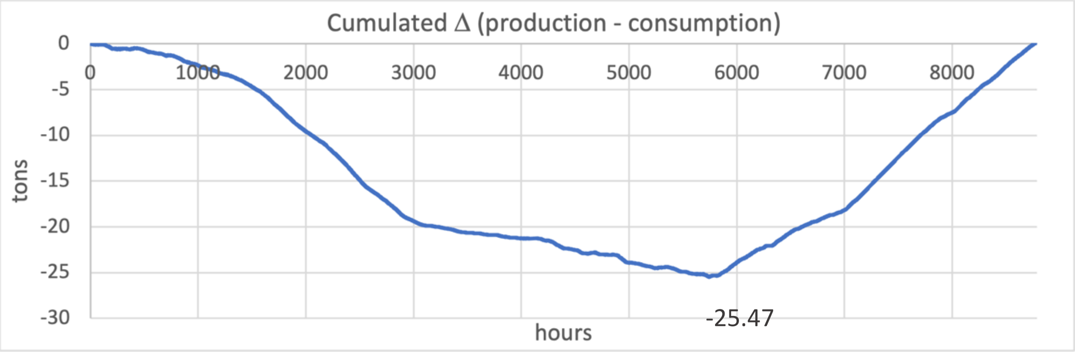


Figure 3. Scenario 4b - Cumulative difference between hydrogen production and consumption

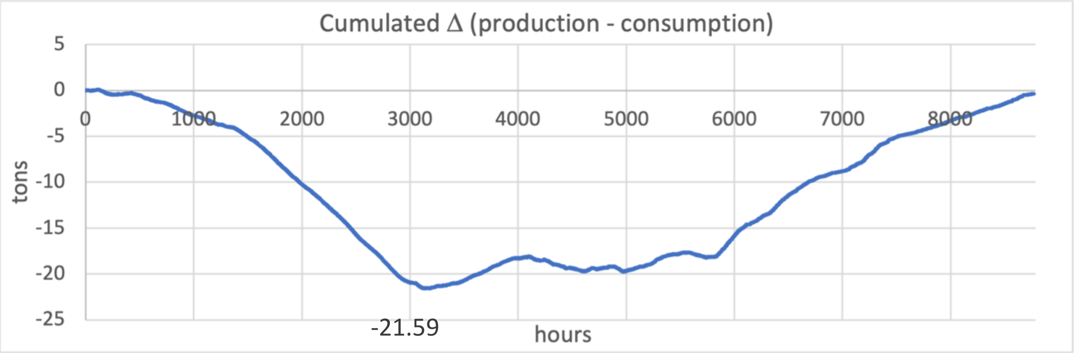


Figure 4. Scenario 4c - Cumulative difference between hydrogen production and consumption

From the figures above, it is possible to understand how the long-term storage reservoir behaves during the year: already in the first months of operation of the heating plant (September and October), the curve is decreasing with negative values because hydrogen production is less than consumption, which means that the long-term storage reservoir is emptying. In contrast to Scenarios 1,2 and 3 with photovoltaic production, in Scenario 4 all (4a and 4b) or most (4c) of the energy production comes from the hydropower plant, which is minimal in the early autumn months. The minimum values of the curves reach lows of -26.66, -25.47, -21.59 tons, respectively. As described in Section 5.3.4, this minimum value was assumed to be the minimum long-term storage capacity required to couple hydrogen production and consumption. The increasing part of the curve represents the period from January/February to August, when production exceeds consumption and storage is loaded again. The null value at 8784 hours implies that long-term storage has been sized correctly, with overall production equaling consumption.

It can be seen that the main difference between the three curves is due to the different availability of renewable power input to the electrolyzer. In fact, in Scenario 4a, the curve is steeper and with a lower minimum value (and thus a higher required capacity of the storage), as hydro power is available only when the PUN is less than 70 €/MWh. On the contrary, in scenario 4b, hydropower is available at a percentage set at 3.6 percent of the nominal capacity of the San Silvestro power plant, regardless of the time value of the PUN, resulting in higher availability of the power itself and thus a flatter storage state-of-charge curve.

Finally, in scenario 4c there is a further decrease in the minimum required storage capacity due to the combined use of hydroelectric and photovoltaic power, which promotes less decoupling between hydrogen production and consumption and a more stable storage state-of-charge curve.

Finally, all parameters adopted for each unit were written into a Matlab script, linked to the Simulink file containing the global system model, to run the simulation.

The script for Scenarios 4a, 4b and 4c are available in the appendices.

2. Simulation Results

The simulation results were grouped into a subsystem called "Results" within the global system model (see 5.2). The variables that best represent the behavior of the system during the simulation are:

- o The hydroelectric/photovoltaic power available on an annual scale;
- o The available hydroelectric/photovoltaic power and the reference power of the electrolyzer for 72 hours of operation, for a better understanding of the daily dynamics.
- o The annual pressure trends of buffer storage and long-term storage;

Graphs of the above variables for the simulation of Scenario 4a, 4b and 4c are shown below.

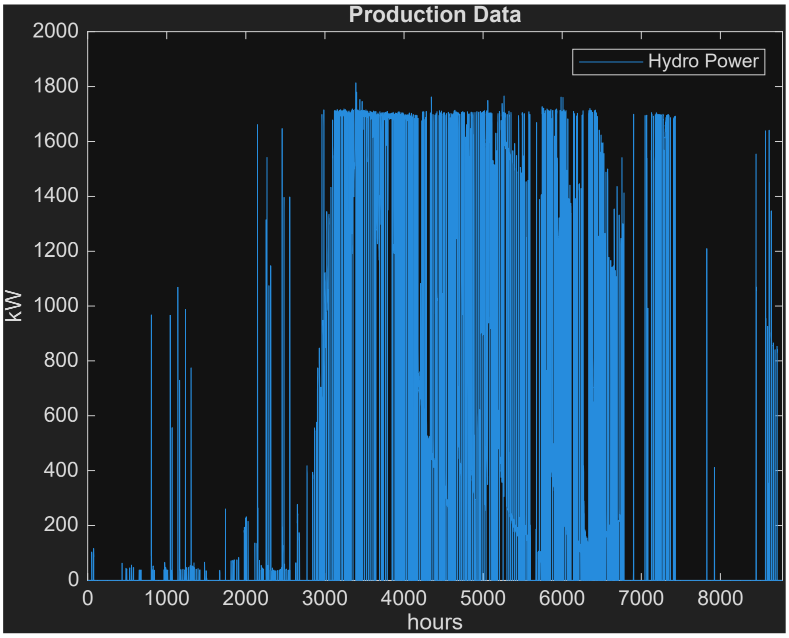


Figure 5. Scenario 4a - Annual available hydroelectric power

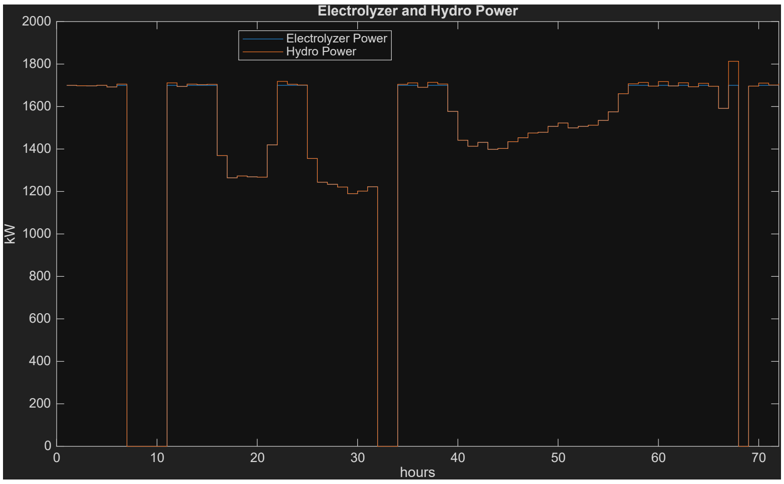


Figure 6. Scenario 4a - Hydropower and electrolyzer power (three days trend)

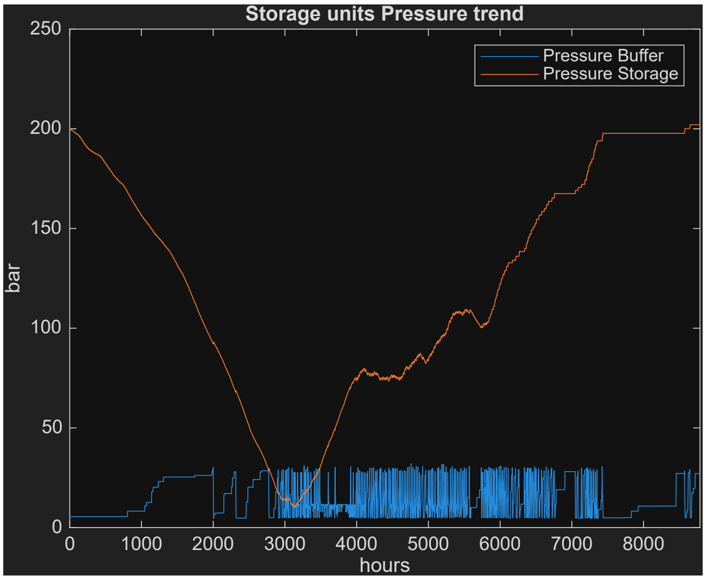


Figure 7. Scenario 4a - Annual pressure trends of storage tanks.

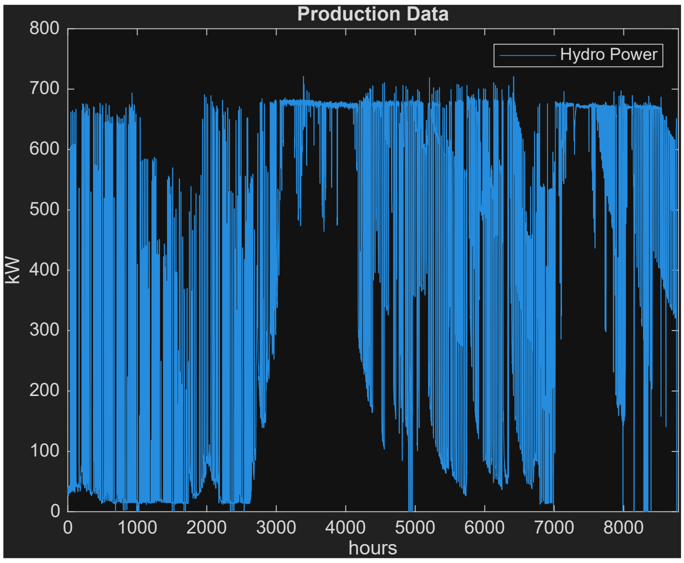


Figure 8. Scenario 4b - Annual available hydropower

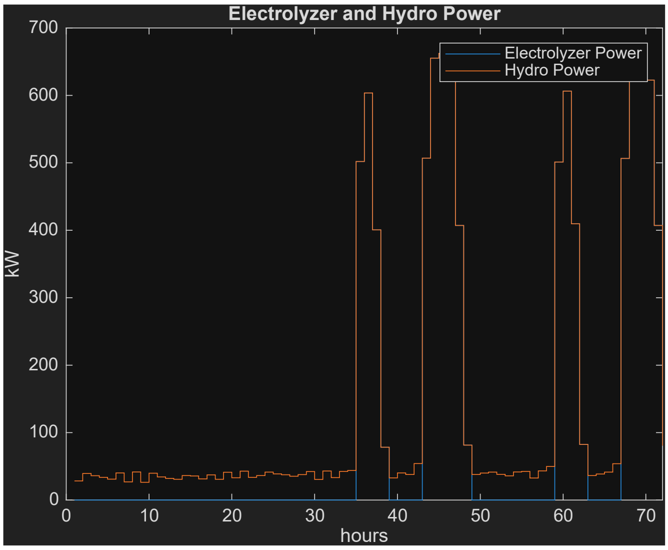


Figure 9. Scenario 4b - Hydropower and electrolyzer power (three days trend)

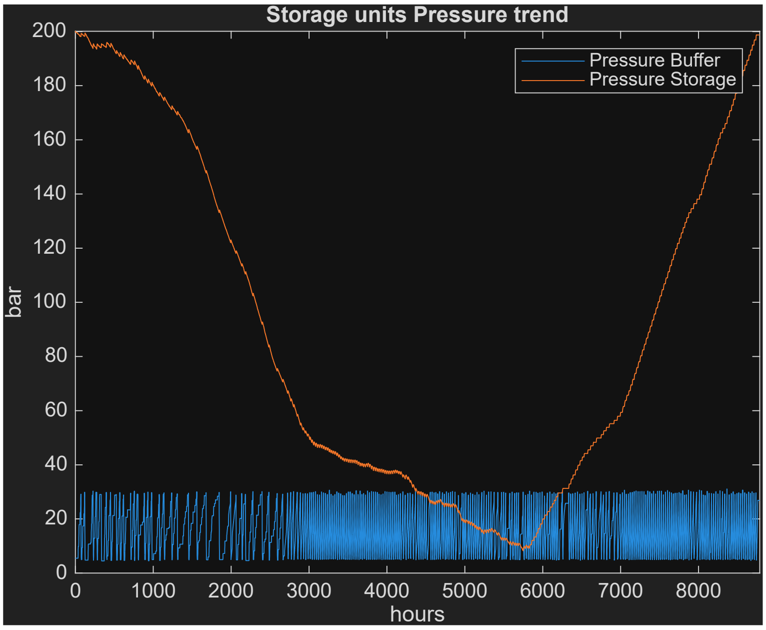


Figure 10. Scenario 4b - Annual pressure trends of storage tanks.

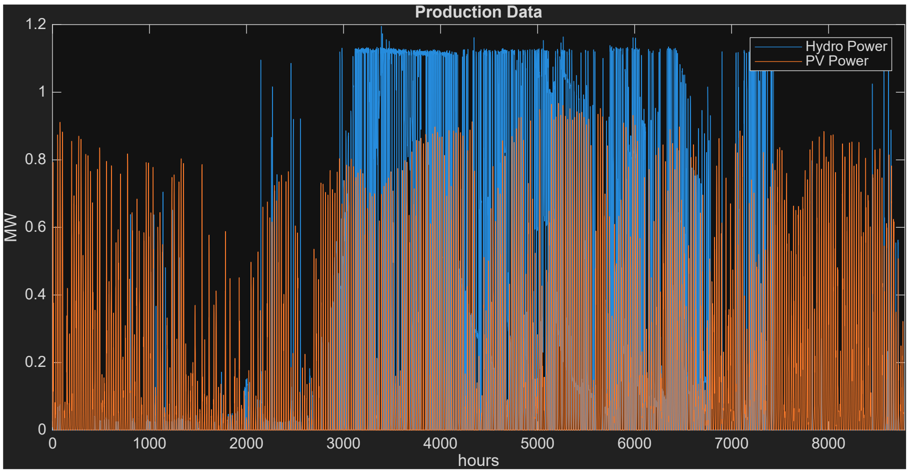


Figure 11. Scenario 4c - Annual available hydropower and photovoltaic power produced.

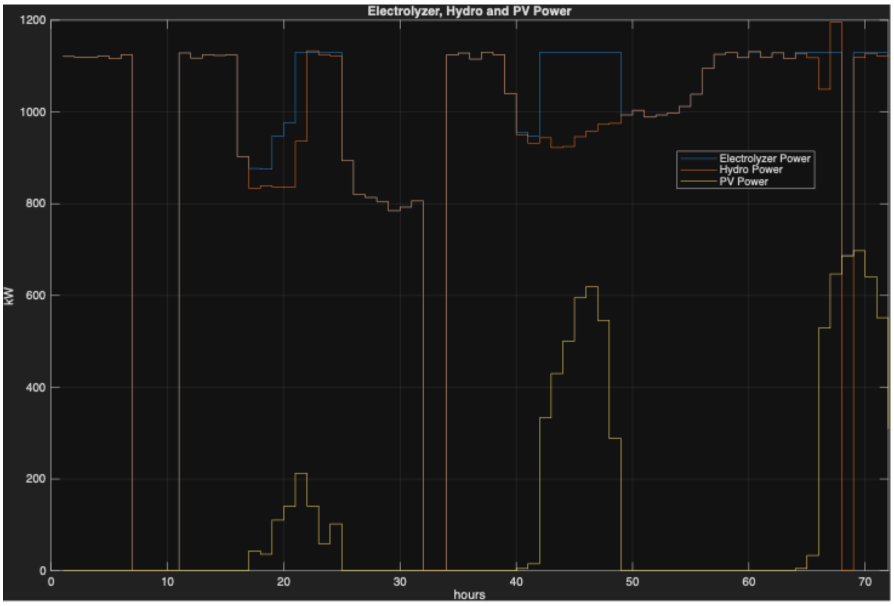


Figure 12. Scenario 4c - Photovoltaic power, hydropower and electrolyzer power (three days trend)

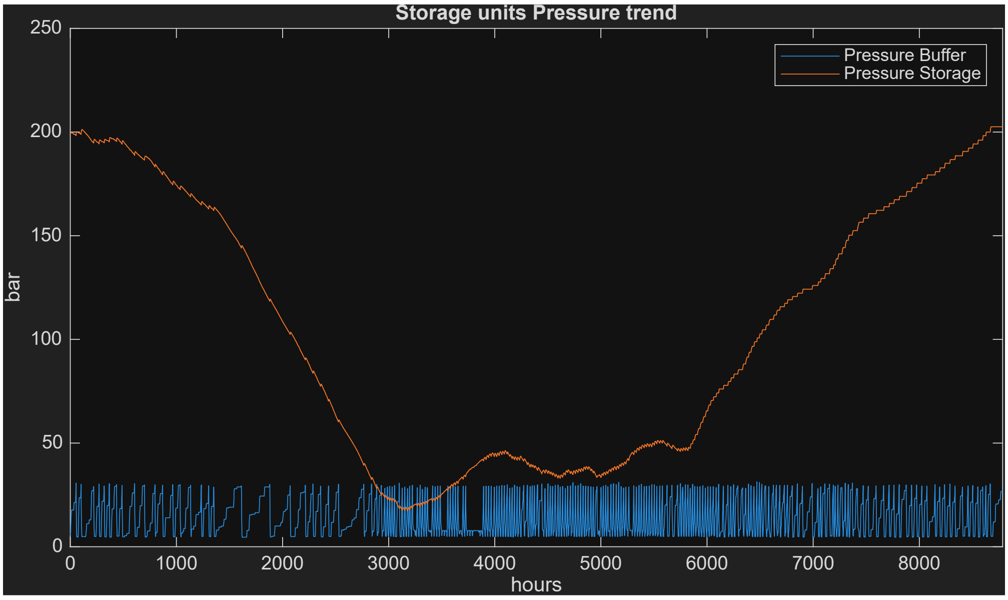


Figure 13. Scenario 4c - Annual pressure trends of storage tanks.

3. Cost Analysis and Land Occupation

3.1 Cost Analysis

The main components of the system for which to determine costs are:

1) PV system

The cost estimate for an on-site PV system depends on the power and complexity of the installation. For a ground-mounted system, the estimated on-site cost varies between €900 and €1,100/kWp, so €1,000/kWp is adopted as the reference value.

Below are the costs for The different Scenarios considered:

o Scenario 4a - Hydroelectric with PUN threshold: 0 €.

o Scenario 4b - Hydroelectric without PUN threshold: 0 €

o Scenario 4c - Hydroelectric + photovoltaic with PUN threshold: 950,000 €.

2) Electrolyzer

As for estimating the cost of electrolyzers, since it is not a widely used technology, research was conducted on different sources and manufacturers to estimate the cost.

REF.	Ref. year	Size [MW]	CAPEX [€/kW]
https://www.eneaconsulting.com/static/3663dbb115f833de23e4c94c8fa399ec/enea-the-potential-of-power-to-gas.pdf	2016	0,5	2000
	2016	1	1500
	2016	10	1000
https://doi.org/10.1016/j.ijhydene.2018.07.164	2019	2	750
	2017	5	1100
https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/cost-forecast-for-low-temperature-electrolysis.pdf	2020	5	949
	2020	100	663
	2030	5	726
	2030	100	444
https://www.irena.org/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf	2020	>1	750-800 $/kW
https://assets.ey.com/content/dam/ey-sites/eycom/en_in/topics/energy/2023/02/ey-shortage-of-electrolyzers-for-green-hydrogen-v2.pdf?download	2023		700-1100 $/kW
https://www.iea.org/energy-system/low-emission-fuels/electrolysers	2023		500-1400 $/kW

Table 2. Unit cost of electrolyzers

Based on the above table, a specific average cost value of 1,000 €/kW is assumed.
Below are the costs for The different Scenarios:

- o Scenario 4a - 0 €
- o Scenario 4b - 0 €
- o Scenario 4c - 950,000 €.

3) Buffer

Buffer costs were estimated on a literature basis. The following parameters were taken into account to estimate a reliable cost:

- Standard cost of Hydrogen tanks
- Pressure tanks from 15 to 250 bar
- Complexity of installation.

Based on the above considerations, a specific tank cost evaluated in €/kg of stored hydrogen was estimated. This value is equal to 500 €/kg of H2.Di seguito i costi per i 6 scenari:

Scenario	**Buffer Capacity (kg)**	**Buffer Cost (€)**
Scenario 4a	200	20,000
Scenario 4b	200	20,000
Scenario 4c	200	20,000

Table 3. Buffer tank cost

4) Long-term storage system.

The buffer cost estimate was estimated on a literature basis.

The following parameters were taken into account to estimate a reliable cost:

- Standard cost of Hydrogen tanks
- Pressure tanks from 15 to 250 bar
- Complexity of installation.

Based on the above considerations, a specific tank cost evaluated in €/kg of stored hydrogen was estimated. This value is equal to 500 €/kg of H2. Below are the costs for the 6 scenarios:

Scenario	**Storage Capacity (kg)**	**Storage cost (€)**
Scenario 4a	26600	2,660,000
Scenario 4b	25470	2,547,000
Scenario 4c	21590	2,159,000

Table 4. Long-term storage tank costs.

5) Compression system.

Different scenarios operate at different pressures and flow rates. Evaluation of compressor costs is given for each system. Below are the costs:

- Scenario 4a: 20,000 €
- Scenario 4b: 20,000 €
- Scenario 4c: 20,000 €

6) Civil works and ancillary plant works.

The estimation of costs related to civil works, not having to specific information related to the installation site, it is possible to make it only on the basis of general evaluations and types of similar installations, providing a percentage value with respect to the main plant engineering works (Electrolyzer, storage system and compressor system, PV system).

The civil works to be carried out for this type of plant are estimated to involve (simplifying and non-exhaustive list):

- Excavation and earthwork
- Concrete foundations.
- First rain collection system
- Manufactures to be used as technical rooms
- Electrical system (lighting and FM)
- Water system (water distribution and treatment)
- Compressed air system
- Fire detection and protection system

The aforementioned works are estimated to affect 10% of the cost of the facilities.

7) H_2 transport works.

Also for estimating the costs of the H2 transport and distribution system, reference was made to a specific value calculated as €/m of pipeline in place.This value was calculated as:

$$Invest\left[\frac{€}{m}\right] = \mathrm{Invest}_A * D^2 + \mathrm{Invest}_B * D + Invest_C$$

Parameter	**Value**	**Unit**
Pressure in	20	bar
Pressure out	2	bar
Invest. A	0.0022	€/mm^2
Invest. B	0.86	€/mm
Invest. C	247.5	€

Table 5. Parameters adopted for estimating the cost of hydrogen transport works

The value for a 10" pipe is estimated at about €247.50/m. Below are the route lengths of the respective scenarios:

- Scenario 4a: 500 m – 0.12 M€
- Scenario 4b: 500 m – 0.12 M€
- Scenario 4c: 500 m – 0.12 M€

8) Total costs of energy production

Below is a table containing a summary of the costs of each component and the total costs for the different scenarios.

Cost Figures [M€]	Scenario 4a	Scenario 4b	Scenario 4c
PV Plant	0.0	0.0	0.95
Electrolyzer	1.70	0.70	1.13
Compressor	0.02	0.02	0.02
Buffer	0.02	0.02	0.02
Storage	2.66	2.55	2.16
Transportation works	0.12	0.12	0.12
Civil and plant works	0.3	0.1	0.3
Total	**4.8**	**3.5**	**4.7**

Table 6. Estimated total costs for the different Scenarios.

Below is a table containing the cost of energy produced for each scenario. The energy cost is calculated by determining the energy produced during the useful life of the plant, which is estimated to be 20 years.

Parameter	Unit	Scenario 4a	Scenario 4b	Scenario 4c
Total costs	M€	4.8	3.5	4.7
Electrical energy produced annually	MWh/year	3,636	3,636	3,636
Thermal energy saved annually	MWh/year	2,000	2,000	2,000
Electrical energy produced in useful life	MWh	72,727	72,727	72,727
Thermal energy saved in useful life	MWh	40,000	40,000	40,000
Specific cost of energy produced from H2	**€/kWh$_{H2}$**	**0.120**	**0.088**	**0.118**

Table 7. Specific cost of hydrogen energy produced for each Scenario.

3.2 Land Occupation

For scenarios 4a and 4b, there are no plans to install new construction facilities, as the energy needed to power the electrolyzer comes directly from the San Silvestro hydroelectric power plant. Therefore, land occupation in the above scenarios is minimal and related only to the footprint of the electrolyzer and storage tanks. For Scenario 4c, the photovoltaic systems are planned to be installed on roofs of industrial buildings.

From a feasibility analysis and on the data provided, the available areas are about 133,00 m2, an area that is vastly greater than the required area, which is about 4,400 m2, or 3.4 % of the total available areas.

4. Comparative Analysis

In order to assess the reduction of climate-changing gases, it is necessary to evaluate the emission values of CO2 equivalent for different fossil sources and compare the emissions produced per unit of energy consumed (CO2/MWh year) with the same for the fossil source.

Below are the emission values, updated to 2022, of the main sources used for domestic heating (natural gas, LPG, Diesel, and electricity).

- Natural Gas: 0,190 kgCO2eq./kW
- GPL: 0,170 kgCO2eq./kWh
- Diesel Oil: 0,228 kgCO2eq./kWh
- Electricity Grid: 0,530 kgCO2eq./kWh

Parameters	Unit	Scenario 4a,b,c
Electric energy produced	MWh/year	3,366
Thermal energy used	MWh/ year	2,000
Natural gas emissions reduction	ton$CO_{2,eq}$/ year	380
LPG emissions reduction	ton$CO_{2,eq}$/ year	340
Diesel oil emissions reduction	ton$CO_{2,eq}$/ year	456
Grid electricity emissions reduction	ton$CO_{2,eq}$/year	1,060

Table 8. Estimated reduction in CO2 equivalent emissions for Scenarios 4a, 4b and 4c

For the scenarios considered, reference is made to thermal energy carriers only; therefore, savings in terms of CO2 equivalent can be evaluated with reference to the replacement of fossil-fired thermal plants.

5. Risk Analysis associated with project implementation

The following analysis relates estimated system costs to a potential increase due to:

- Increased demand for PV systems and system equipment in general,
- Increase due to assessment not adhering to future scenarios of system costs,
- Increase due to exogenous and unforeseeable factors.

The potential increase was estimated at the value of 20 %. The comparison was conducted either by increasing all components by 20 percent or by increasing the individual cost item by 20 percent and estimating its impact on the total cost.

1) 20% Increase of PV Costs

Sensitivity Analysis	**Unit**	**Scenario 4a**	**Scenario 4b**	**Scenario 4c**
Cost of photovoltaics	M€	0.0	0.0	1.14
Total cost	M€	4.8	3.5	4.9
Specific cost of energy produced from H2	€/kWh$_{H2}$	0.120	0.088	0.123
Percentage increase in cost/cost of energy produced	%	+0%	+0%	+4.02%

Table 9. Sensitivity analysis for change in PV costs.

2) 20% increase in cost of electrolyzer

Sensitivity Analysis	**Unit**	**Scenario 4a**	**Scenario 4b**	**Scenario 4c**
Electrolyzer cost	M€	2.04	0.84	1.36
Total cost	M€	5.12	3.66	4.95
Specific cost of energy produced from H2	€/kWh$_{H2}$	0.128	0.092	0.124
Percentage increase in cost/cost of energy produced	%	+7.11%	+3.98%	+4.79%

Table 10. Sensitivity analysis for change in electrolyzer costs.

3) 20% increase in cost of compressors

Sensitivity Analysis	**Unità**	**Scenario 4a**	**Scenario 4b**	**Scenario 4c**
Compressor cost	M€	0.02	0.02	0.02
Total cost	M€	4.79	3.53	4.72
Specific cost of energy produced from H2	€/kWh$_{H2}$	0.120	0.088	0.118
Percentage increase in cost/cost of energy produced	%	0.08%	0.11%	0.08%

Table 11. Sensitivity analysis for change in compressor costs.

4) 20% Increase of buffer tank costs

Sensitivity Analysis	**Unit**	**Scenario 4a**	**Scenario 4b**	**Scenario 4c**
Buffer tank cost	M€	2.66	2.55	2.16
Total cost	M€	4.79	3.53	4.72
Specific cost of energy produced from H2	€/kWh$_{H2}$	0.120	0.088	0.118
Percentage increase in cost/cost of energy produced	%	0.08%	0.11%	0.08%

Table 12. Sensitivity analysis for change in buffer tank costs.

5) 20% increase in seasonal storage costs

Sensitivity Analysis	**Unit**	**Scenario 4a**	**Scenario 4b**	**Scenario 4c**
Seasonal storage cost	M€	0.12	0.12	0.12
Total cost	M€	5.32	4.03	5.15
Specific cost of energy produced from H2	€/kWh$_{H2}$	0.133	0.101	0.129
Percentage increase in cost/cost of energy produced	%	11.12%	14.46%	9.15%

Table 13. Sensitivity analysis for long-term storage tank cost variation

6) 20% increase in cost of H2 transport works.

Sensitivity Analysis	**Unit**	**Scenario 4a**	**Scenario 4b**	**Scenario 4c**
Cost of transp. works	M€	0.15	0.15	0.15
Total cost	M€	4.81	3.55	4.75
Specific cost of energy produced from H2	€/kWh$_{H2}$	0.120	0.089	0.119
Percentage increase in cost/cost of energy produced	%	0.52%	0.70%	0.52%

Table 14. Sensitivity analysis for cost variation of hydrogen transport works.

7) 20% increase in cost of civil and plant works

Sensitivity Analysis	**Unit**	**Scenario 4a**	**Scenario 4b**	**Scenario 4c**
Civil works cost	M€	0.31	0.13	0.38
Total cost	M€	4.84	3.54	4.78
Specific cost of energy produced from H2	€/kWh$_{H2}$	0.121	0.089	0.120
Percentage increase in cost/cost of energy produced	%	1.09%	0.63%	1.35%

Table 15. Sensitivity analysis for cost change in civil and plant works

8) 20% increase in total costs

Finally, the following table shows the change in total system costs if total costs increase by 20 percent.

Sensitivity Analysis	**Unit**	**Scenario 4a**	**Scenario 4b**	**Scenario 4c**
Total Costs	M€	5.74	4.23	5.66
Specific cost of energy produced from H2	€/kWh$_{H2}$	**0.144**	**0.106**	**0.142**

Table 16. Sensitivity analysis for change in total system costs.

From the analysis of costs and risk associated with variability, it is noted that the greatest impact is associated with the cost of the PV system, electrolyzer, and seasonal storage, so it will be necessary to evaluate their impact carefully:

- Photovoltaic technology has reached a very advanced level of commercial development. Significant cost deviations are not to be expected, except for possible availability crises related to significant increases in demand or criticality in the supply system.

- Electrolyzer technology is continually evolving; there are production facilities with capacity exceeding current demand. This makes it possible to envision availability and a trend of cost reduction, but it represents a significant risk factor because of the high cost of operating plants that are not utilized to their full capacity. **Probably the cost of electrolyzers is the real risk factor of an investment in this sector today and requires special attention when evaluating the offer.**

- Pressure tank technology up to 250 bar is well established, and cost tensions leading to significant deviations are not imaginable.