Politecnico di Milano

SCHOOL OF INDUSTRIAL AND INFORMATION ENGINEERING

Master of Science – Energy Engineering

Multi-Objective Approach for Energy Planning in Energy Communities

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Sommario

Il decennio 2020 – 2030 vedrà profonde trasformazioni nel sistema energetico e sarà cruciale per gli obiettivi climatici. Mentre il sistema tradizionale era basato su pochi impianti centralizzati e flussi di energia unilaterali, la visione futura si configura in un sistema sempre più decentralizzato, sostenibile, elettrificato, intelligente e flessibile, con molti piccoli impianti di produzione distribuiti, un'alta percentuale di energie rinnovabili, strategie di storage e una partecipazione attiva dei cittadini. Quest'ultimo aspetto, in particolare, è la direzione che le direttive del Clean Energy Package hanno avviato nel 2018 e nel 2019 con l'introduzione del concetto di "*comunità energetiche*", cioè entità in cui cittadini, PMI e autorità locali possono cooperare in un'attività legata all'energia, con scopi non commerciali. Tramite le comunità energetiche i cittadini assumono parte del potere decisionale legato allo sviluppo del sistema energetico in una certa area. Partendo da tale contesto, questa tesi si pone lo scopo di offrire al policy maker uno strumento per esplorare come il sistema energetico di una regione si potrebbe sviluppare in seguito alla nascita di una comunità energetica. L'evoluzione del sistema energetico viene analizzata in base a diversi obiettivi, che rappresentano le preferenze del policy maker (minimizzazione delle emissioni di CO_2 o degli scambi con la rete di alta tensione) o della comunità energetica (minimizzazione dei costi per i consumatori). I singoli obiettivi sono poi uniti in una ottimizzazione multi-obiettivo risolta tramite un criterio globale e un metodo dei pesi. In questo modo il policy maker può valutare quanto lo sviluppo ottimo per la comunità energetica possa essere funzionale al raggiungimento dei suoi obiettivi. In altre parole, può essere in grado di stabilire una serie di regole, incentivi e vincoli che indirizzino correttamente l'evoluzione del sistema energetico nell'area considerata.

Parole chiave: comunità energetiche, ottimizzazione multi-obiettivo, prosumers, elettrificazione

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Abstract

The decade 2020 – 2030 will undergo profound transformations in the energy system and will be crucial for the climate agenda. While the traditional system was based on a few centralized plants with unilateral energy fluxes, the current vision foresees a system increasingly decentralized, sustainable, electrified, smart and flexible, with many small and distributed power plants, a high percentage of renewable energies, storage strategies and an active citizen participation. The latter aspect, in particular, is the direction that the Clean Energy Package directives started in 2018 and 2019 with the introduction of the concept of "*energy communities*", i.e. entities in which citizens, SMEs and local authorities can cooperate in an energy-related activity with non-commercial purposes. Through the energy communities, citizens assume an active role in promoting an energy policy linked to the development of the energy system in a certain area. Given this context, this thesis aims to constitute a tool for the policy maker to explore how an energy community would affect the energy system of a region. The development of the energy system is analyzed on the basis of various objectives, which represent the preferences of the policy maker (minimization of CO_2 emissions or of the exchanges with the high voltage grid), or of the energy community (minimization of costs for the consumers). The single objectives are then merged in a multi-objective optimization solved by means of a global criterion and a weighted sum methodology. In this way the policy makers can evaluate how the optimal development for the energy community can be functional to the achievement of their own objectives. In other words, they can be able to establish a series of rules, incentives and constraints that can correctly direct the evolution of the energy system in the considered area.

Key words: energy communities, multi-objective optimization, prosumers, electrification

Extended Abstract

Introduction

The decade 2020 – 2030 will undergo profound transformations in the European energy system and will be crucial for the climate agenda towards the middle of the century. After the liberalization directives of the ‘90s that opened the energy market across all Member States, the Clean Energy Package [3] of 2018 and 2019 is defining the path that the energy system will undertake in this period. Other than the updates on the climate and energy targets – at least 40% cuts in greenhouse gas emissions, 32% renewables in energy consumption and 32.5% higher efficiency in energy use – the package foresees a key role of citizens for the achievement of the European goals thanks to the diffusion of the energy communities. These are legal entities where citizens, SMEs and local authorities self-organize in an energy-related activity based on open and democratic participation and governance, whose primary purpose is to provide benefits to the members and to the local community [6]. By gathering into a single entity, citizens can take part in the transition towards a fully decarbonised energy system by 2050 by proactively investing in their own renewable power plants, by increasing the flexibility in demand-response schemes and, more generally, by obtaining part of the decision making power of an area over the development of the local energy system. After presenting the PNIEC [15] (Piano Nazionale Integrato per Energia e Clima) to the European Commission as its National Energy and Climate Plan with a first reference to them, the Italian government has formally introduced the energy communities with Law 28 February 2020, n. 8 [16], even if in a temporary configuration, with limitations in the maximum power capacity to install and with the incentive to the shared energy still to be defined. Their potential, according to a 2016 study by CE Delft [12], is that 45% of the electricity consumption in Europe and 40% in Italy could be potentially produced by energy communities in 2050. Moreover, the PNIEC sets a renewable energy target in the heating sector of 33.9% by 2030, that will be mostly be achieved thanks to the adoption of heat pumps (HPs), to be owned by citizens. Starting from this context, it is clear that the energy system will have to be shaped to cope with the climate and sustainability targets but, eventually, other goals and constraints of economic, technical and social nature may rise and influence the outcome. Additionally, with more decisional power given to the citizens thanks to the diffusion of community energy schemes, the traditional actors in the energy system will have to account for the objectives of the new energy communities as well. Therefore, by knowing all the possible directions that the energy system of an area may take, the policy maker can have the possibility to set a number of rules, incentives and constraints to influence its development towards the best approach with respect to the energy community goals.

Model

For this purpose, a multi-objective optimization model is designed and coded in this thesis. This type of optimization is able to optimize a multiple objective problem, where the final goals often conflict with each other. An analysis of the literature was performed and different methods were found. In Li [44] a double-objective optimization considering costs and emissions of a district energy network constituted by a neighbourhood of four buildings is optimized according to a weighted sum methodology, where each objective is assigned a weighting factor and the multi-objective function is minimized accordingly, therefore having an objective with the shape $Obj = opt \sum_{i=1}^{k} \alpha_i \cdot f_i(x)$, where $f_i(x)$ are the single objective functions, x the vector of the solutions and α_i the weight factors to assign to each function i. In Silva [47], a similar approach is used in the optimization of a rural electrification scenario with as much as four objectives, i.e. costs, employment, land use and avoided emissions, where each one is assigned a preference factor that, similarly to the weighted sum method, increases the importance of a certain objective in the multi-objective approach. Zhang [45], instead, offers an example of ε-constraint method, where only one function is minimized while assigning upper or lower constraints to the others, in the shape $Obj = opt\left[f_j(x)\right],\ f_i(x) \lesseqgtr \varepsilon_i,\ i = 1, \dots, k,\ i \neq j$ where ε_i are the constraints of the objective function i, with the purpose of optimizing the design of a distributed generation system considering costs, emissions and acidification objectives. Lastly, Chiandussi [46] reorganizes all the methods to solve multi-objective problems and describes a further procedure, the global criterion, where the differences of all objectives with respect to their ideal values are simultaneously minimized, therefore having $Obj = opt \sum_{i=1}^{k} \left[\left(f_i^0 - f_i(x)\right)/f_i^0\right]^p$, where f_i^0 is the target value of the objective function i, $f_i(x)$ its current value in the multi-objective approach and p an exponentiation factor that in most cases is unitary.

Following these approaches, the model presented in this thesis is built by considering three objective functions:

- Minimization of fluxes through the transformation primary substation,
- Minimization of CO_2 emissions by energy consumption, and
- Minimization of costs for electricity and heating.

The optimization is performed by optimizing the additional generation, storage capacity and heat pumps mix, whereas the objective functions are merged in a multi-objective optimization problem solved by means of a global criterion and a weighted sum methodology. It is important to highlight that the model refers to the optimization of the energy system of an area where an energy community is assumed to be introduced, where, in particular, the area is defined as the set of citizens and municipalities afferent to a single transformation primary substation. In order to simplify the computation and to avoid the need to model the energy and monetary exchanges among different energy communities in a single area, two important assumptions are defined to be that 1) all citizens living in an area join the energy community and 2) only one energy community is introduced in each area. This assumption reflects both the most recent Italian normative, i.e. Law 28 February 2020, n.8 [16] that limits the energy communities to be afferent to a single substation, and the radial shape of the Italian electricity grid, where a single primary substation covers different municipalities and, viceversa, each municipality is reached by a single substation. Performing an energy planning of an area, consequently, corresponds, first, to optimize the utilization of the existing electricity infrastructure without the need to install new transmission lines among different areas and, second, to allow considerations on the electricity self-consumption and independency from the grid. In practice, even if different energy communities are introduced in a single area, the model neglects their multiplicity and considers them as an aggregate.

In order to properly evaluate the energy need evolution of an area, new loads relevant to the electrification of domestic heating equipment have been modelled. The heating demand profile is first of all generated by performing a redistribution of the annual energy demand for heating according to the temperature profile, the heating habits, the heating normative and the buildings features, after which an electrification is simulated by means of two heat pumps technologies. The procedure is performed for each single household, whose single outcomes can be summed up to obtain the overall heating profile. The first input, therefore, is the total annual primary energy consumption for heating of an entire area – i.e. a set of households – PE_i of each source of energy i and its conversion into useful energy E_i by means of average conversion efficiencies η_i of each source, $E_i[kWh] = PE_i \cdot \eta_i$. However, since the focus of the model is the electrification of heating, the already electrified sources are removed from the calculations since they are already comprised in the electric load, obtaining in this way the annual useful energy demand for heating that can be electrified for the purposes of this model:

$$E_{Non-electric}[kWh] = \sum_{i=Non-electric} E_i \tag{1.1}$$

At this point the households are considered, for which the total number $N[-]$, the average surface $S[m^2]$, the average annual energy consumption specific to the surface $e[kWh/year \cdot m^2]$ and the assumed daily operating hours of the domestic heating plant $hours[h]$ are required. In this way, the annual heating demand of a single household can be calculated:

$$E_{Heating}\left[\frac{kWh}{year}\right] = e\left[\frac{kWh}{year \cdot m^2}\right] \cdot S[m^2] \cdot \frac{hours[h]}{24[h]} \tag{1.2}$$

Now it is possible to singularly simulate the real heating behaviour for each household. First of all, a reference temperature T_{ref} is randomly assumed, i.e. the indoor temperature below which the heating system is switched on and provides heat according to the normative D.P.R. n. 74/’13 [17], therefore having $T_{ref} = 20 \pm 2\ [°C]$. Then, a temperature difference profile $\Delta T(t)$ can be found: $\Delta T(t) = T_{ref} - T(t)$, where $T(t)$ is the outdoor temperature profile. At this point, an important passage is the modification of the $\Delta T(t)$ profile by accounting for the frequency of use of the domestic heating plant and the occupation frequency of the household, so that a nonnull $\Delta T(t)$ is existing only when the heating plant is used and nullified in those timesteps where the domestic heating plant is simulated to be switched off:

$$\Delta T(t) = \begin{cases} \Delta T(t), & t \in t_{Switched-on} \\ 0, & t \notin t_{Switched-on} \end{cases} \tag{1.3}$$

Finally, the profile for heating $P'_{Heating}(t)$ can be obtained by multiplying the annual energy consumption $E_{Heating}$ per a factor representing the share of $\Delta T(t)$ over the sum of all the temperature differences at all timesteps $\sum_t \Delta T(t)$:

$$P'_{Heating}(t)[kW] = E_{Heating} \cdot \frac{\Delta T(t)}{\sum_t \Delta T(t)} \tag{1.4}$$

However, $P'_{Heating}(t)$ is the useful energy for heating profile but it has to be modified such that only the non-electrified energy demand for heating is comprised. In order to do this and after summing the profiles of each household, it is enough to multiply all the values in $P'_{Heating}(t)$ per a multiplication factor FM defined as $FM[-] = E_{Non-electric} / \sum_t P'_{Heating}(t)$. Consequently, the heating profile $P_{Heating}(t)$ can be obtained by multiplying each timestep per the factor FM:

$$P_{Heating}(t)[kW] = P'_{Heating}(t) \cdot FM = P'_{Heating}(t) \cdot \frac{E_{Non-electric}}{\sum_t P'_{Heating}(t)} \tag{1.5}$$

An example of the obtained profiles is shown in Figure 1.1 that refers to a test area. To clarify the meaning of such profile, notice that this corresponds to the profile of the final heating demand exclusively satisfied by nonelectric sources, that is the profile that can be potentially electrified.

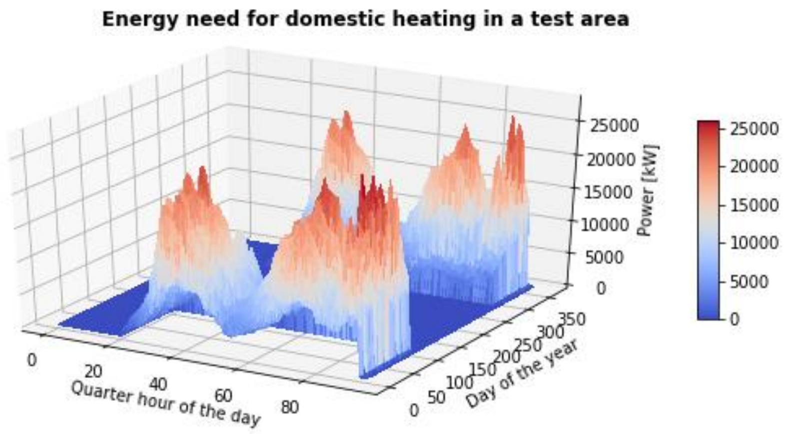

Figure 1.1 - Example of heating profile

Now that the heating profile $P_{Heating}(t)$ is obtained, the following step is the electrification of heating by considering different heat pump technologies and by assuming a COP varying with the temperature $COP_j(\Delta T)[-]$ according to Staffell [25]. However, knowing the temperature difference profile $\Delta T(t)$, it is possible to obtain the COP_j for each heat pump technology j as a function of time t: $COP_j(\Delta T) = COP_j(\Delta T(t)) = COP_j(t)$. Consequently, the electrical power needed to cover the heating power demand $P_{Heating}(t)$ by each technology j can be obtained:

$$P_j^{Heating}(t)[kW] = \frac{P_{Heating}(t)}{COP_j(t)} \tag{1.6}$$

Once the heating profile is calculated, the real multi-objective model can be built. More in detail, in all scenarios the energy balance equation is always valid and needs to be accounted for:

$$L_{EE}(t) + L_{Heating}(t) - \sum_k x_k \cdot p_k(t) + F_{Battery}(t) = Z^+(t) + Z^-(t) \tag{1.7}$$

where:

- $L_{EE}(t)$ is the power transit of an area, i.e. the electric power flowing through the transformation primary substation that is positive when entering and negative when exiting the area;
- $L_{Heating}(t) = \sum_j x_j \cdot P_j^{Heating}(t)$ is the additional electric load by electrifying the heating demand, where the variables x_j represent the fraction of the heating demand to be covered by each heat pump technology j whose sum is equal to the overall electrification $\sum_j x_j = f_{Heating}$;
- $\sum_k x_k \cdot p_k(t)$ is the additional electricity generation, where x_k are the variables representing the generation capacities of each source k to install and $p_k(t)$ the normalized generation profiles;
- $F_{Battery}(t)$ are the power fluxes from the battery, that depend on a single free variable $C_{Battery}$ which is the storage capacity and can be either positive or negative;
- lastly, $Z^+(t) > 0$ and $Z^-(t) < 0$ are the resulting residual profiles through the primary substation and are entering and exiting the area, respectively.

Always considering the energy balance equation, three different objective functions can be specified. First, the objective regarding the minimization of the fluxes through the transformation primary substation is defined:

$$\begin{aligned} Objective_{Fluxes} = min(Fluxes_{Tot}) = min\left(\sum_t^{8760\cdot 4} \left(Z^+(t) - Z^-(t)\right)\right) \\ = Fluxes_0[kWh] \end{aligned} \tag{1.8}$$

where $Fluxes_0$ is the minimum total fluxes obtained by singularly minimizing the fluxes objective.

Then, the minimization of a quantity NPC representing the Net Present Cost with a 20 years horizon is defined as the second objective:

$$Objective_{Costs} = min(NPC) = min\left(Cost_{Investment} + \sum_{n=1}^{20} \frac{Cost_{O\&M} + Cost_{Variable}}{(1+i)^n}\right) = NPC_0[€] \tag{1.9}$$

where $Cost_{Investment}$ is the total investment cost of the additional generation plants, the storage capacity and the heat pumps, $Cost_{O\&M}$ is the total annual cost for the fixed O&M of all the installed systems, $Cost_{Variable}$ the total annual operation cost, n the assumed life of the investment equal to 20 years, i the discount rate assumed to be equal to 0.03 to actualize the costs and NPC_0 the minimum possible NPC obtained by singularly minimizing the costs objective. It is important to clarify that, despite being usually defined in relative terms in an investment analysis, the Net Present Cost represents here the actualized total costs that the consumers will have to sustain during the lifetime of the project, rather than the economic convenience of the investment.

Lastly, the minimization of the CO_2 emissions by the energy consumption is the third objective function:

$$Objective_{Emissions} = min\left(E_{Generation}^{CO_2} + E_{Grid}^{CO_2} + E_{Heating}^{CO_2} + E_{Battery}^{CO_2}\right) = Emissions_0 \tag{1.10}$$

where $E_{Generation}^{CO_2}$ are the annual emissions by the additional generation, $E_{Grid}^{CO_2}$ the emissions embedded in the electricity coming from the grid, $E_{Heating}^{CO_2}$ the emissions by heating and $E_{Battery}^{CO_2}$ the emissions by the production of the battery system.

All objectives depend on a set of free variables, namely the additional electricity generation capacity x_k of each source k, the fraction of the heating demand x_j covered by each heat pump technology j and the storage capacity $C_{Battery}$.

When applying the multi-objective methods to the case of this thesis, the following equation should be considered. In the global criterion method, the optimization problem is defined as follows:

$$Objective_{Global} = min\left[\left(\frac{Fluxes_{Tot} - Fluxes_0}{Fluxes_0}\right) + \left(\frac{Emissions_{Tot} - Emissions_0}{Emissions_0}\right) + \left(\frac{NPC_{Tot} - NPC_0}{NPC_0}\right)\right] \tag{1.11}$$

where all the single objective functions are simultaneously considered and are minimized such that the sum of the normalized differences between the punctual and the lowest values possible is minimized.

Applying the weighted sum method, instead, the optimization problem should have the following definition:

$$Objective_{Weight} = min\left[\alpha \cdot \frac{Fluxes_{Tot}}{Fluxes_0} + \beta \cdot \frac{Emissions_{Tot}}{Emissions_0} + \gamma \cdot \frac{NPC_{Tot}}{NPC_0}\right] \tag{1.12}$$

where α, β and γ are the multiplication factor to assign to each single objective function to represent its weight in the overall function, defined such that their sum is unitary, $\alpha + \beta + \gamma = 1$. The results that are obtained are a mix of the solutions found by considering the objective functions singularly and depend on the coefficients α, β, γ of each scenario. Qualitatively, the higher the weight of an objective, the closer are the solutions to the ideal values of that objective. Moreover, the problem will have the shape and visualization of a ternary diagram.

A number of constrains is defined in the optimization problem. For what concerns the additional generation capacity to be installed by each source k in each area, two different scenarios are defined. The “unbounded potential” scenario foresees a cap equal to 30 MW for the additional capacity of each source, where this value is defined such that it is large enough to not constitute an excessively limiting constraint in the optimization. On the other hand, the “bounded potential” scenario sets the caps for each technology according to the overall nominal power already installed, assuming that each source installed capacity can be at most doubled, or according to the total roof surface for PV, assuming that only 20% of the total surface can be covered by solar panels. Then, the electrification fraction is of course lower than 1 and the air-to-water technology is assumed to be eventually installed in only the most recent households. The maximum storage capacity to be installed in each area is defined to be 100 MWh. Lastly, the residual profiles $Z^{+}(t)$ and $Z^{-}(t)$ are given an upper and lower bound, respectively, by knowing the nominal power of the transformer(s) of the primary substation and by neglecting the influence of a power factor in the transformation process, assuming that, for the primary substations with more than one transformers, the maximum fluxes correspond to the nominal power of the transformer with the highest nominal capacity increased by 20%.

Results

The model is applied to each of the seventeen areas of Valle d’Aosta, which are defined as the set of municipalities whose electric energy provision is performed by a single transformation primary substation. The names of the areas are listed in Table 1.1. The tests, developed within a cooperation between Politecnico di Milano and Regione Valle d’Aosta, are particularly significant as they represent an implementation of the proposed methodology on real-life study cases. The real generation data provided by the region are used to obtain a set of characteristic generation profile of each source normalized with respect to the plant nominal capacity. Moreover, a simplified clustering is performed for the hydro source and three recurrent profiles are distinguished: the hydro A is defined as the one with null production in winter and a drastic change in summer up to almost unitary normalized generation; hydro B presents a higher production in winter and a sudden increase in summer up to 0.8 normalized generation; lastly, hydro C shows more constant normalized generation along the year with an average value around 0.4.

Table 1.1 - Names of the areas in Valle d'Aosta

Area	**Name**
A1	Aosta ovest
A2	Ayas
A3	Covalou
A4	Cretaz
A5	Entreves
A6	Gressoney
A7	Morgex
A8	Nus
A9	Perreres
A10	Pont Saint Martin
A11	Pont Saint Martin 2
A12	Aosta ponte pietra
A13	Pré Saint Didier
A14	Rhins
A15	Verres
A16	Villeneuve – Cogne
A17	Zuino

According to the results, minimizing the fluxes implies a high share of CHP and bio source in the additional capacity with "unbounded potential", null heating electrification and maximum storage. The minimization of the emissions comes together with hydro, PV and wind, maximum electrification and maximum storage. Lastly, the costs objective sees an important presence of the hydro source, varying electrification depending on the area and null storage. By solving the multi-objective problem with a global criterion optimization, the solutions obtained are a combination of the single-objective results. In particular, it seems that hydro C type – i.e. the one with most constant profile along the year – is the most suitable to minimize all objectives simultaneously as shown in Figure 1.2. On the other hand, by estimating the actual availability of each source in each area according to the "bounded potential" scenario – where PV is found to be the most available source – almost the maximum potential by the hydro and CHP sources is installed together with a PV trade-off capacity, as in Figure 1.3.

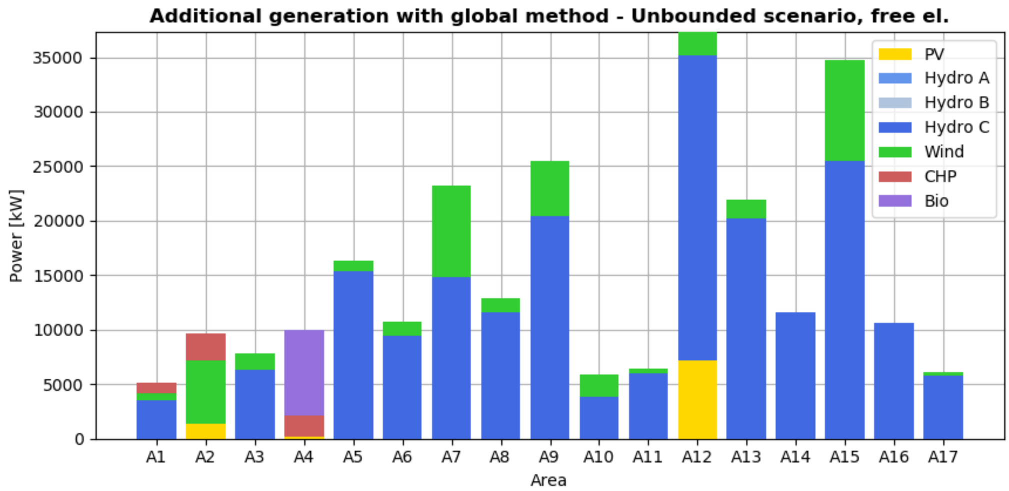

Figure 1.2 - Results with global criterion optimization in unbounded potential scenario

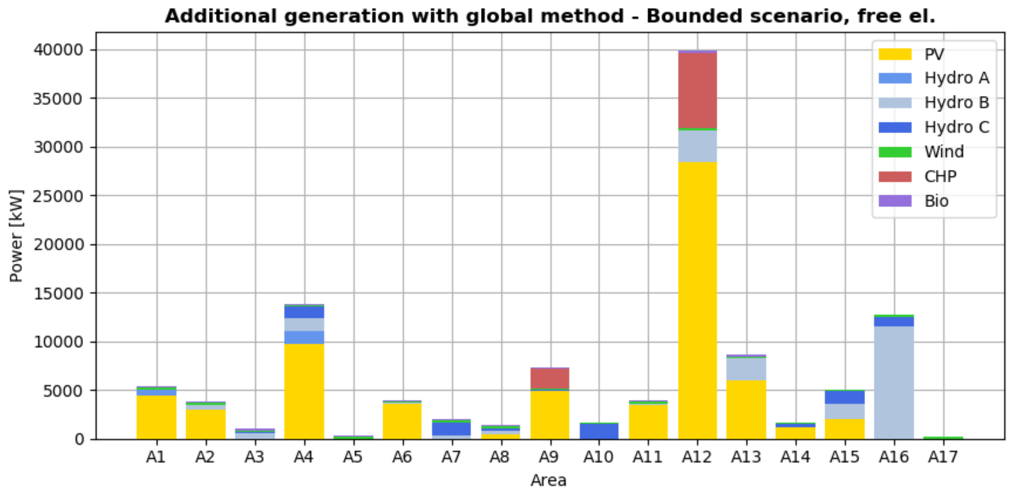

Figure 1.3 - Results with global criterion optimization in bounded potential scenario

The weighted sum optimization obtains a set of solutions that have the shape of a ternary diagram. Intuitively, the higher the weight of an objective, the closer the results to its single-objective solutions. Showing only the results with "unbounded" generation potential for area A12 *Aosta ponte pietra* in Figure 1.4 as an example, it is possible to see how the optimal solutions change with the objectives weights. Notice that the vertices of the triangle are related to the maximum weight given to each objective and the stacked bars found in those positions correspond to the results of the single-objective functions.

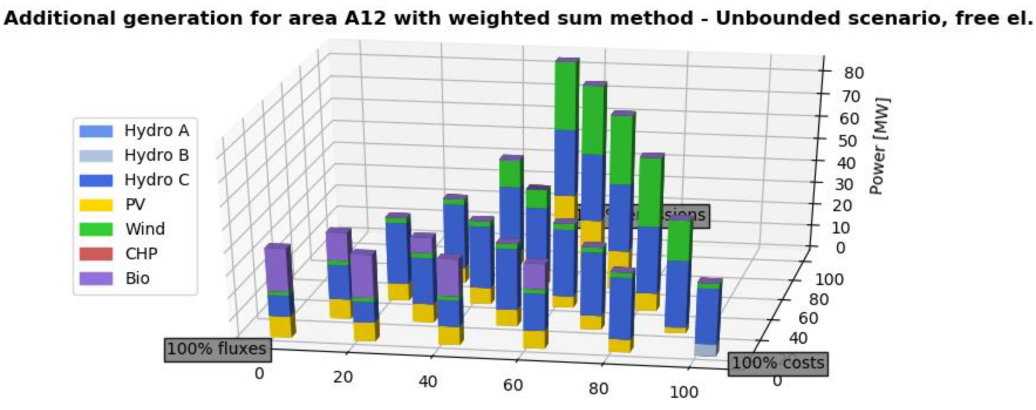

Figure 1.4 - Results with weighted sum methodology in unbounded potential scenario

Conclusions

The model presented in this thesis has been proved to be able to perform the optimization of an energy planning by considering a multiplicity of objectives merged in a multi-objective problem. The objectives analysed are the minimization of the fluxes through the transformation primary substation, the minimization of the emissions by the energy consumption and, lastly, the minimization of the costs for the consumers. The multi-objective problem is solved, first, with a global criterion and, second, with a weighted sum method, which obtain a different set of optimal solutions by assigning equal and varying weights to each objective, respectively. These objectives can either be pursued by the policy maker, by the citizens in an energy community or by both of them, depending on the preferences and needs of each actor.

It is found that the hydro C source – i.e. the hydroelectric plants with most constant production profile all along the year – is the most suitable source to minimize all the objectives simultaneously. However, if the real potential by each source is estimated as in the “bounded potential” scenario, the hydro C is not as available as in the “unbounded” scenario and, consequently, it is substituted by the PV source, with an extent that depends on the area and on the weights given to each objective function. This is a first outcome of the model: in fact, according to the results, installing PV power plants is convenient to decrease the fluxes, the emissions and the costs at the same time, even if the best technology to do so would be the hydroelectric. For what concerns the electrification, it seems convenient for all areas when minimizing the emissions and for a few areas, depending on many factors related to the residual profiles, when minimizing the costs. If a lower source availability is considered as in the “bounded potential” scenario, electrifying seems even less economically convenient and is nonnull only in those areas where a high and cheap generation surplus is present. In the multi-objective optimization, however, electrification is a selected option for most areas and would help optimize all objectives simultaneously.

Lastly, the storage capacity is maximum when minimizing the fluxes and emissions but is never selected when considering the costs. Consequently, defining incentives to both heat pumps and storage batteries could be the key tool for the policy maker to influence the optimal evolution of the energy system and economically unlock the advantages that these systems could provide to the community.

However, the model is based on some important assumptions necessary to avoid the need to model the energy and monetary exchanges among different energy communities in a single area, that may be not enough verisimilar for certain areas. Furthermore, a number of aspects and possibilities has been neglected to simplify the model as well. For this reason, some additional features could be considered and introduced in future developments in order to obtain more solid, complete and detailed results and, in this way, build a model able to better represent the complexity of a local energy system. Among the further developments, there are:

- Model not only the direct costs but the externalities too, since the primary purpose of an energy community is not of economical but rather of social nature and, consequently, some positive externalities such as local development or added value should be considered too;
- Simulate an electrification of not only the heating sector, but also transport and industry;
- Introduce the actual electricity demand rather than the electrical load through the transformation primary substation, so that considerations on incentives to the self-consumption could be performed;
- Couple the electrical with the thermal model, such that the available solutions to decarbonise heat with nonelectrical technologies – district heating, biogas, biomass, etc – can be optimised too according to their availability;
- Consider demand-response schemes.

Relatively to the case study:

- Cluster all sources, especially the hydro, in a more detailed way, by knowing the actual features of each plant;
- Better estimate the real potential of each source in each area;
- Estimate the potential of technologies other than batteries, such as pumped hydro, to better represent the storage potential of each area;
- Perform a sensitivity analysis in each optimization, where the input data are disturbed and different results are eventually obtained, therefore starting an iterative process that ends as soon as the results obtained happen to be within a certain predefined range and obtaining a more solid set of solutions;

- Consider the technical constraints related to the hosting capacity of the LV distribution grid to verify the actual feasibility of installing additional generation capacity.

In any case, the model constitutes a first step in the construction of a tool for the policy maker to simulate the outcomes of sharing part of the decision making power in favour of the citizens, and explore how the energy system would develop by considering different objectives representing the preferences either belonging to the policy maker (minimization of CO_2 emissions or of the exchanges with the high voltage grid) or to the energy community (minimization of costs for the consumers). In this way the policy maker can evaluate how the optimal development for the energy community can be functional to the achievement of the objectives of the policy maker him or herself or, in other words, he or she can be able to establish a series of rules, incentives and constraints that can correctly direct its evolution towards the direction that he or she has the necessary information to know that are better for the overall community.

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Chapter 1
Introduction

Following the first directives concerning the creation of common energy market rules at EU level, the European Union has started defining the new gradual transition towards a fully decarbonised energy system thanks to the Clean energy for all Europeans package of 2018 and 2019. Differently from the directives of the previous years, the Clean Energy Package foresees a key role for citizens which are put at the heart of the energy transition by having the possibility to influence their energy footprint, whether by installing smart meters, by controlling their household bills or by investing in renewables power plants to produce, store and share their own electricity and sell it to the grid.

In particular, the Clean Energy Package sets a number of targets by 2030, the main of which are:

- At least 40% cuts in greenhouse gas emissions,
- At least 32% renewables in energy consumption, and
- At least 32.5% higher efficiency in energy use.

In order to reach this goal, Member States are required to draft a National Energy and Climate Plan (NECP) for the period 2021-2030 – for which Italy has already presented the PNIEC (Piano Nazionale Integrato per Energia e Clima) in January 2020 in its final definition setting a National renewable objective of 30% by 2030 – as well as a further long-term strategy for the next 30 years. Moreover, at Union level, the strategy concerning the full integration and cooperation among each country's TSOs, already started with the liberalization directives of 1996-2009, is furtherly empowered in the new package, such that the improved interconnections can increase both the efficiency and flexibility of the market and, especially, the energy security at EU level. Also, new measures to monitor and tackle energy poverty are introduced. Finally, citizens are strengthened to take an active and proactive role in the energy transition and be part of the solution to reach a fully decarbonised energy system by the middle of the century.

Citizens are the centre of this thesis as well. Following the introduction of the concept of "*energy communities*" – group of individuals, institutions and enterprises that take common decisions regarding their energy needs – and the estimates about their potential diffusion at EU level – suggesting that by 2050 almost half of the EU households could produce renewable energy, – it analyses the case and potential impacts of a decentralized, and hence more democratic, energy system. Also, a number of electrification scenarios are taken into account and simulated, where heat pumps partially or entirely substitute the non-electrified energy sources for heating and contribute to a further decarbonisation.

Starting from this context, when dealing with the energy planning of a region, multiple and diverse objectives and constraints of economic, environmental, technical, landscaping, health and political nature, which are often conflicting to each other and hard to be respected or reached simultaneously, have to be taken into account. Furthermore, if more decisional power is given to citizens as in the case of the energy communities, the energy system could be affected in different ways according to the goals of the citizens themselves. Consequently, the goal of this thesis is to develop a tool for the policy maker to explore how the energy system would develop by considering different objectives – namely the minimization of the fluxes through the distribution electric grid, the annual CO_2 emissions by the energy consumption and the costs for the consumers – representing the preferences, either belonging to the policy maker or to the energy community, that have the power to shape the evolution of the energy system itself. In this way, the policy maker, having the necessary information to know which objectives would bring the major benefits to the society, can evaluate how the optimal development for the energy community can be functional to the achievement of those objectives and can set a number of rules, incentives and constraints to influence the development of the energy system towards them. A model, shaped as a multi-objective optimization problem and solved by means of a global criterion and a weighted sum methodology, is introduced and described for this purpose.

The thesis is structured in the following way.

In the second chapter the current trends in the energy system are shown and the European and Italian targets contained in the PNIEC are presented. A particular focus is put on the concepts of electrification and sector coupling, which are illustrated in terms of both advantages and challenges for the energy system. The European market for the heat pumps, the key technology to electrify and decarbonise heat, is analysed and the barriers to their diffusion at Italian level are explained.

In the third chapter the European and National normative on the energy communities are unfolded, considering both the Renewable and Electricity Directives of the Clean Energy Package and highlighting the differences between the definitions. The National transposition by the Italian government is also introduced. Then, the diffusion potential of the energy communities in EU28 is illustrated with a focus on the single countries.

In the fourth chapter the state of the art in the multi-objective optimization is mathematically formalized. A focus is put on the most diffused techniques currently in use – namely the global criterion, the weighted sum methodology and the ε-constraints method – with examples of application by real cases.

In the fifth chapter, after justifying the main hypotheses and assumptions, the model is mathematically formalized, and all parameters, variables, objectives and constraints of the generation, load, heating and storage are introduced.

In the sixth chapter the case study related to Valle d'Aosta is illustrated, starting from the generation profiles and the input load used in the model. Also, a large part is dedicated to the generation of the heating demand profile by considering an electrification scenario with heat pumps, having as input data the annual energy needs of each municipality, the temperature profiles and the heating habits of the citizens. Such case study, developed thanks to a cooperation between Politecnico di Milano and Regione Valle d'Aosta, has been adopted in order to test and validate the proposed approach in a real-life scenario.

In the seventh chapter the main results of the analysed scenarios are presented and explained, beginning with the examination of the impacts of electrification and the single objectives and concluding with the multi-objective optimization problems. Since the number of the considered areas – i.e. the set of municipalities afferent to a single transformation primary substation – is equal to 17, it was chosen to show the results preferentially for area A12 *Aosta ponte pietra* as an example and leave the others in the Annex.

Lastly, in the eighth chapter a summary of the results is made and the further developments of the model are explained.

Chapter 2
Electrification and Sector Coupling

The model simulates the installation of renewable power plants and the adoption of heat pumps to decarbonize and electrify the electricity and heating demand. Therefore, this chapter shows the current trends in the energy system, starting from the renewable targets at European level and continuing with the decarbonization, electrification and sector coupling strategies that will be achieved to reach those targets. Both advantages and challenges of electrification are illustrated. Then, the European market of the heat pumps, the key technology to electrify and decarbonise heat and the barriers to their diffusion at Italian level are explained.

2.1 Trend in the energy system

Renewable targets

In Europe, the adoption of long-term strategies in all sectors and the unexpected cost reductions achieved by key renewable technologies, such as PV and wind, resulted in a strong growth in renewables energy consumption from 9% in 2005 to 16.7% in 2015 [22]. Starting from this, new targets were set by the Clean Energy Package [3] for the period up to 2030 in accordance with the goal of maintaining the temperature rise well below 2°C established by the Paris Agreement:

- At least 40% cuts in greenhouse gas emissions,
- At least 32% energy consumption from renewables, and
- At least 32.5% higher efficiency in energy use, especially in the building sector.

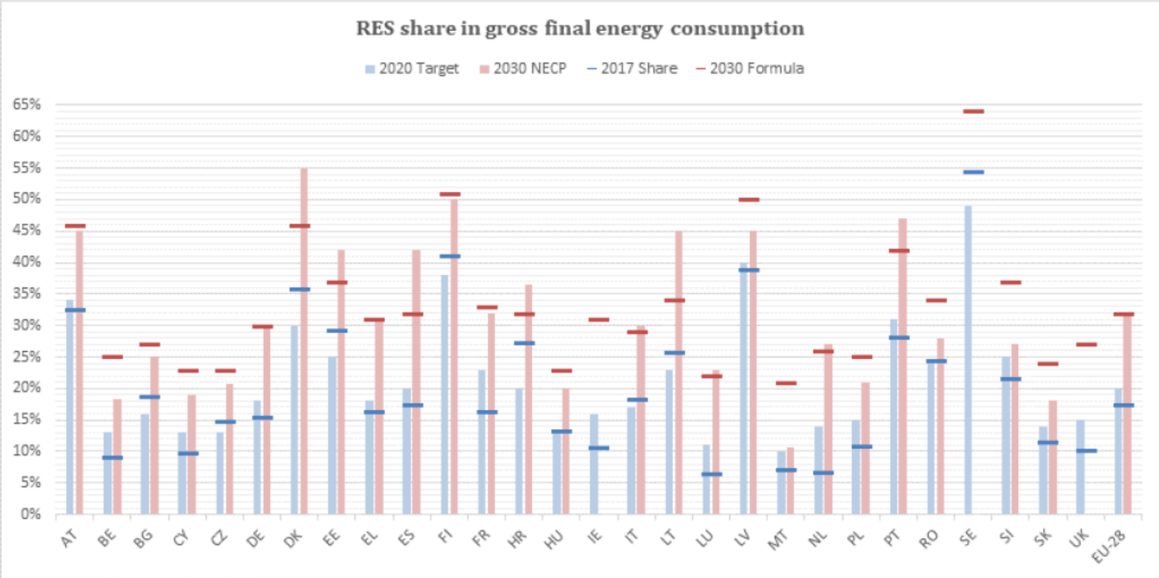


Figure 2.1 - Renewable target by 2030 per Member State [5]

As required by the CEP, the main Italian objectives contained in the PNIEC (Piano Nazionale Integrato per Energia e Clima) were presented in January 2020 in their final definition in accordance to the ones set by the EU [15]:

- At least 33% cuts in non-ETS greenhouse gas emissions,
- At least 30% renewables in energy consumption, and
- At least 43% more efficiency in energy use.

Table 2.1 - Renewable targets per sector at Italian level [15]

	Objectives 2020		**Objectives 2030**	
	EU	**Italy**	**EU**	**Italy PNIEC**
Share of energy from RES in the gross final consumption of energy	20%	17%	32%	30%
Share of energy from RES in the gross final consumption of energy in the transport sector	10%	10%	14%	22%
Share of energy from RES in the gross final consumption of energy for heating and cooling	–	–	+ 1.3% per year	+ 1.3% per year

Reduction in primary energy consumption compared to the PRIMES 2007 scenario	- 20%	- 24%	- 32.5%	- 43%
Final consumption savings as a result of obligatory energy efficiency systems	- 1.5% per year (without transport)	- 1.5% per year (without transport)	- 0.8% per year (with transport)	- 0.8% per year (with transport)
Reduction in GHG vs 2005 for all plants subject to ETS rules	- 21%	–	- 43%	–
Reduction in GHG vs 2005 for all non-ETS sectors	- 10%	- 13%	- 30%	- 33%
Overall reduction in greenhouse gases compared to 1990 levels	- 20%	–	- 40%	–
Level of electric interconnection	10%	8%	15%	10%
Capacity of electric interconnection	–	9,285 MW	–	14,375 MW

The overall Italian renewable target is planned to be reached gradually, with a rate of about +1% annually as shown in Figure 2.2. The electricity sector is intended to be the one with the highest target, with as much as 55% final consumption by RES at 2030, followed by the heating sector with 33.9% and the transport with 22% by 2030, as shown in Figure 2.3, Figure 2.4 and Figure 2.5, respectively.

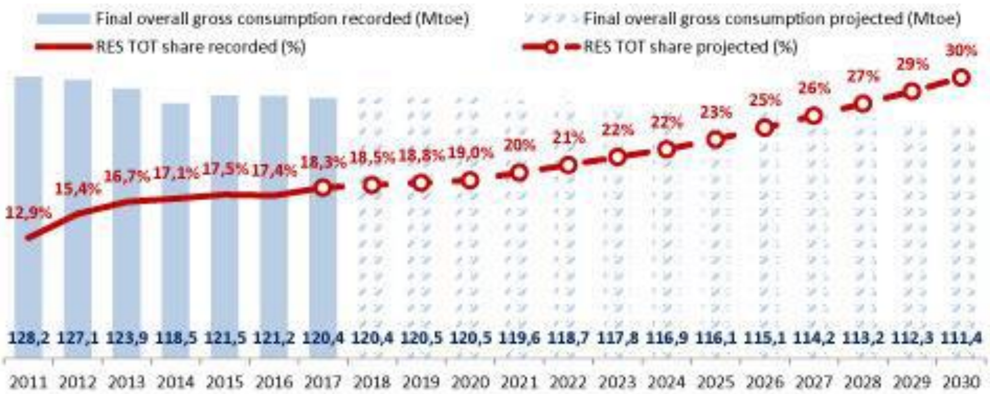


Figure 2.2 – Trajectory of the overall renewable target [15]

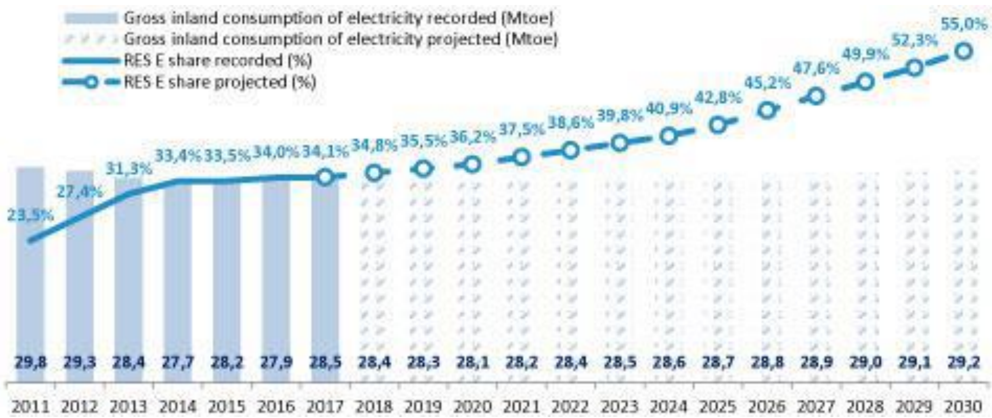


Figure 2.3 - Trajectory of renewable target in electricity sector [15]

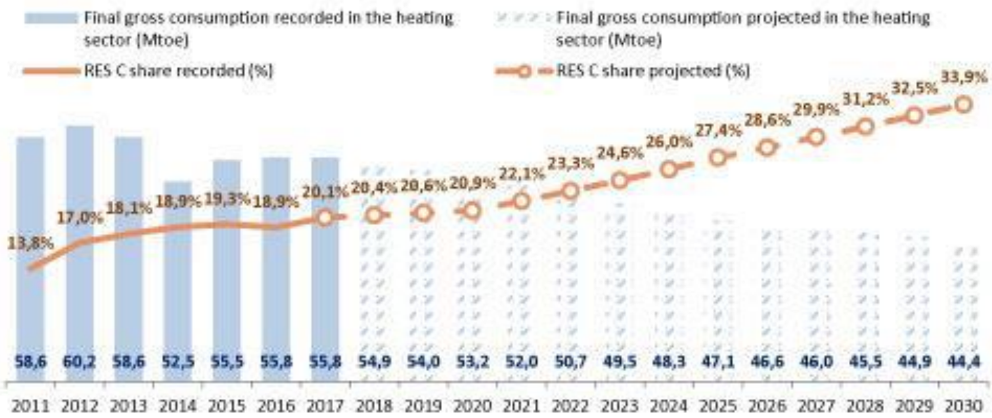


Figure 2.4 - Trajectory of renewable target in heating sector [15]

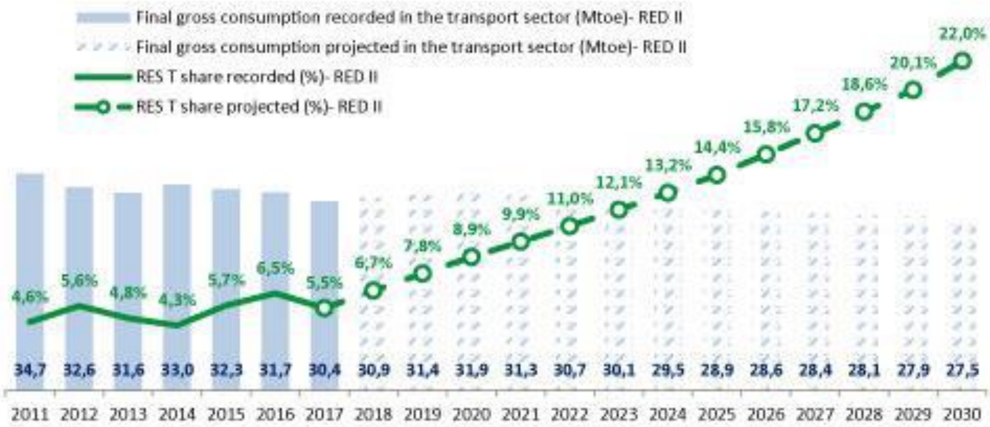


Figure 2.5 - Trajectory of renewable target in transport sector [15]

Focusing on the single sectors, the electricity production by RES sees an increasing contribution by solar PV, which is forecasted to represent the first renewable source by 2030 in terms of electricity production (Figure 2.6). In the heating sector, on the other hand, bioenergy is estimated to maintain its primacy in 2030 even if its contribution will remain constant. Almost all the heating target, in fact, will be covered by a huge increase in the renewable energy production by heat pumps, projected to almost triple their contribution by 2030, therefore considering electrification as the key strategy to decarbonise the sector (Figure 2.7). Lastly, in the transport sector almost all technologies are intended to increase their contribution to the renewable target by 2030, with advanced biomethane with the highest increase rate (Figure 2.8).

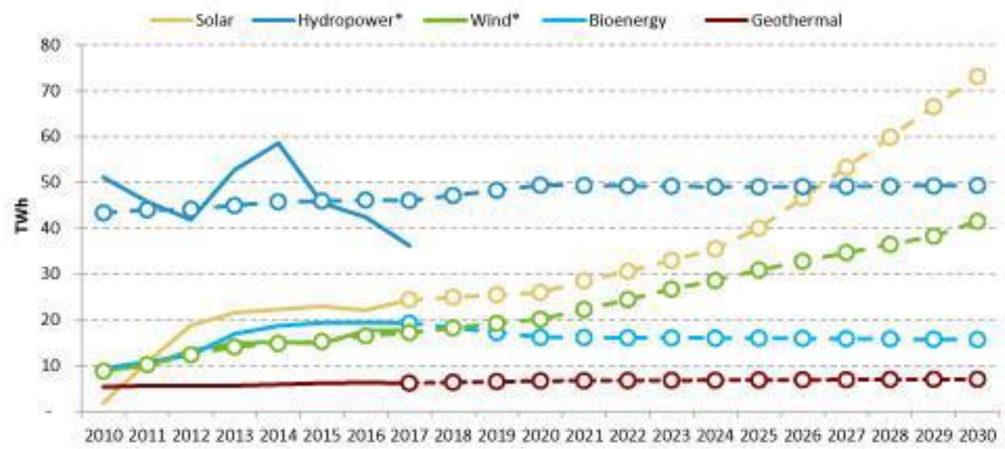


Figure 2.6 - Growth trajectories by source in electricity sector [15]

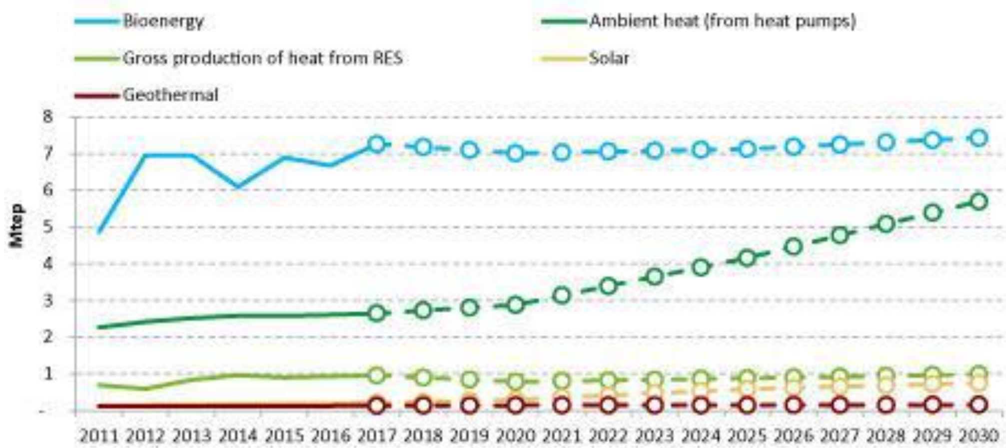


Figure 2.7 - Growth trajectories by technology in heating sector [15]

The additional electricity generation capacity in 2030 planned by the PNIEC sees different contributions by each RES technology. The additional wind generation capacity in 2030 is projected to be about 19.3 GW of which 900 MW of offshore wind, in addition to 19.2 GW by hydroelectric plants, 3.76 GW of bioenergy and 950 MW by geothermal. However, the largest contribution is attributed to solar energy, with as much as 52 GW installed by 2030 of which 880 MW of CSP. The overall additional capacity, about 95 GW, is comparable to the current installed capacity in Italy which is about 120 GW and will make RES the first contributor to the overall generation nominal power [15].

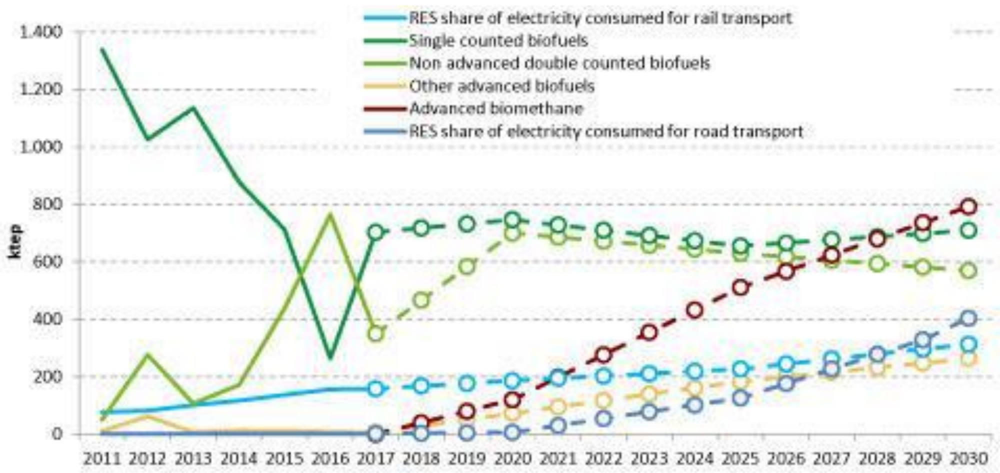


Figure 2.8 - Growth trajectories by technology in transport sector [15]

The innovation in the Clean Energy Package and in the PNIEC, however, is that citizens are seen as a key factor to achieve these targets by owning the majority of the additional RES installations and heat pumps: by taking their own consumption – and production – decisions, and by contributing to shape the whole sector towards a more distributed, democratic, participative, renewable and sustainable energy system, citizens can be the key to make good use of the existing economic advantages of RES, win the system inertia and unlock the real potential of the renewables sources through community energy and self-consumption schemes.

Electrification strategies

Electrification is one of the main tools to reach the renewable targets at 2030, meaning that the main sectors of final energy use – buildings, transport and industry – will have to switch from fossil fuels to electricity as their main energy vector. This is known as "sector coupling" (Figure 2.9), which is the linking of the power sector with transport, heating, cooling and industry, such that it would be possible to use the surplus electricity to heat homes, store heat in district-heating networks or electrical boilers, cool industrial processes and charge the batteries of electric cars, thus helping to replace coal and gas and achieving a fully renewable system. Other than decarbonization, consequently, electrification may come together with higher system flexibility, resiliency, security, independency, as well as economic productivity and improved quality of life for every citizen.

Each of the three main sectors of final energy use – buildings, transport and industry – could be electrified by a certain amount and could contribute to foster the energy system flexibility. According to IRENA [21], the buildings sector, in fact, now uses around 30% of the global final consumption, more than half of which is supplied by natural gas, oil, coal, or biomass, and of which about 70% is consumed by households, with the rest for commercial and government buildings. Currently, electricity supplies only 24% of the energy used in residential buildings and 51% of the energy for commercial and public buildings.

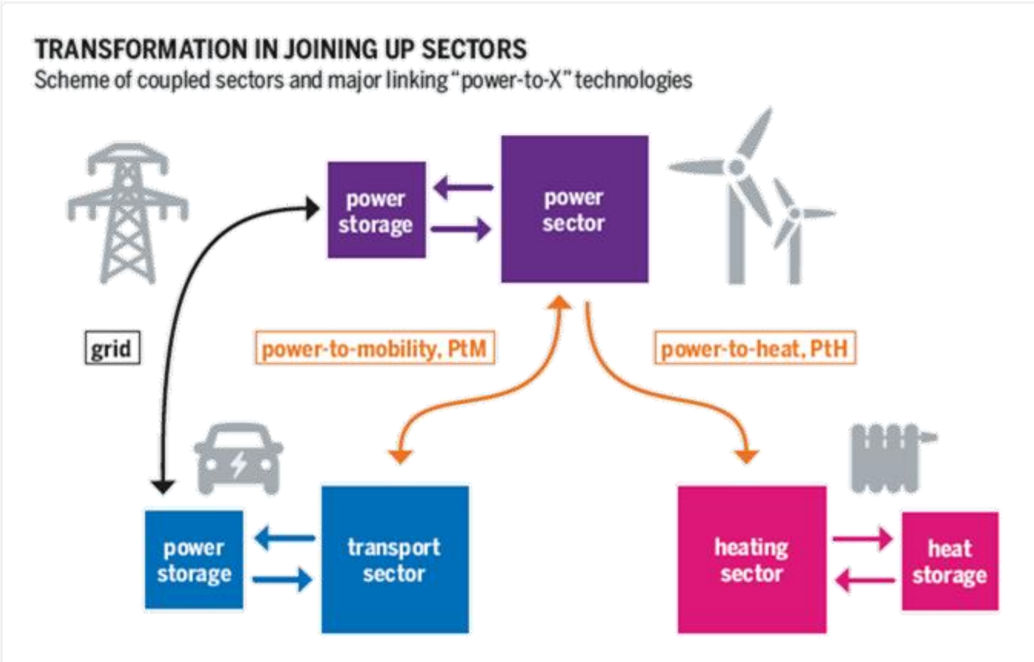


Figure 2.9 - Sector coupling strategy in the energy sector [19]

When talking about electrification in the buildings sector, it means:

- Heat pumps for space heating and hot water;
- Direct electricity use for resistance heating in boilers and furnaces;
- Electricity use to produce hydrogen or syngas;
- Domestic thermal storage;
- Etc.

For what concerns the transport sector, only 1% of total energy use is currently supplied by electricity globally, of which more than two-thirds for rail transport and the rest for tram and subways [21]. Electrification strategies in the transport sector involve:

- Increase the share of EVs on the road;
- Use renewable electricity to make hydrogen to power fuel cell transportation;
- Use renewable electricity to make syngas to replace fossil-based transport fuels;
- Etc.

Lastly, industry is the most challenging final energy sector to decarbonise and electrify, both because of its intrinsic dependency on fossil sources for fuel and feedstocks, and because of the lack of cost-effective substitutions. As of today, only 27% of the industrial energy needs is supplied by electricity especially to power secundary machines such as pumps, motors and heating or cooling units [21]. Electrification of industry means:

- Increase the use of efficient heat pumps for low-temperature heat;

- Adopt electric or hybrid boilers that can switch instantly between electricity and natural gas;
- Replace natural gas fuel and feedstocks with hydrogen or its derivatives produced with renewable electricity where direct electrification is difficult;
- Relocate industrial facilities in regions with low-cost renewable electricity;
- Etc.

Challenges

Expectedly, together with the environmental, social and economic advantages, some challenges rise with electrification. The first problem is that, differently from the combustion power plants – either gas or coal or others, – the renewable plants' production depends on the presence of the primary source at every time, meaning that if in a certain moment the wind flows and the sun shines, the plants will generate electricity, whereas if in another moment there is no sun or wind, they will not generate electricity. This represents an issue because, in order to maintain a nominal grid frequency as much constant as possible (in Europe, 50 Hz with a certain tolerance) the power supply has to be equal to the power demand in every single moment. If the dispatchable sources, such as gas, allow to easily follow the demand and vary the production accordingly, with renewables it is more difficult as they will generate electricity when the primary source is present regardless of the energy demand. This is why, of all these positive outcomes of electrification described before, *flexibility* is not only an outcome but a real requirement of an energy system based on electricity: a flexible system is able to adapt to dynamic and changing generation and/or demand conditions by means of certain technologies and schemes, such that the power supply meets the demand at all time [19]. The second most significant problem will be the increase in peak demand with respect to the current trend: for example, EV charging may raise daily peaks, heat pumps could increase the winter peak especially in the coldest climates, and there will be an overall increase in the average demand with respect to current levels. The main problem with this disproportionate increase in peak demand is that much of the grid infrastructure required to meet the peaks would be used only for short time periods, i.e. when the peaks will occur, consequently making the investment economically unviable [21].

These problems can be solved through a smart management of the demand. An electrified energy system, in fact, – where buildings, transport and industry use electricity for their needs – corresponds to an interconnected and synergetic system. Surplus electricity could be used to produce and store hydrogen for the indutrial processes or to heat and store water in a domestic tank, a power shortage may be solved by exploiting the energy stored in the batteries or by decreasing the charging power for the EVs. Road vehicles, in particular, are interesting as they are parked about 90% of the time, so it is quite easy to optimise their charging schedule using smart power management tools to follow the variations in supply, or even in vehicle-to-grid (V2G) configurations, where the energy stored in their batteries is used to balance the supply-demand equation. Other flexible demand schemes are smart grids that allow an optimal control over small loads and generation plants in “demand-response” configurations, that can be either virtual power plants (VPP) – distributed energy resources such as small-scale solar and storage – or demand aggregators – i.e. consumers who are willing to adjust their immediate collective power consumption.

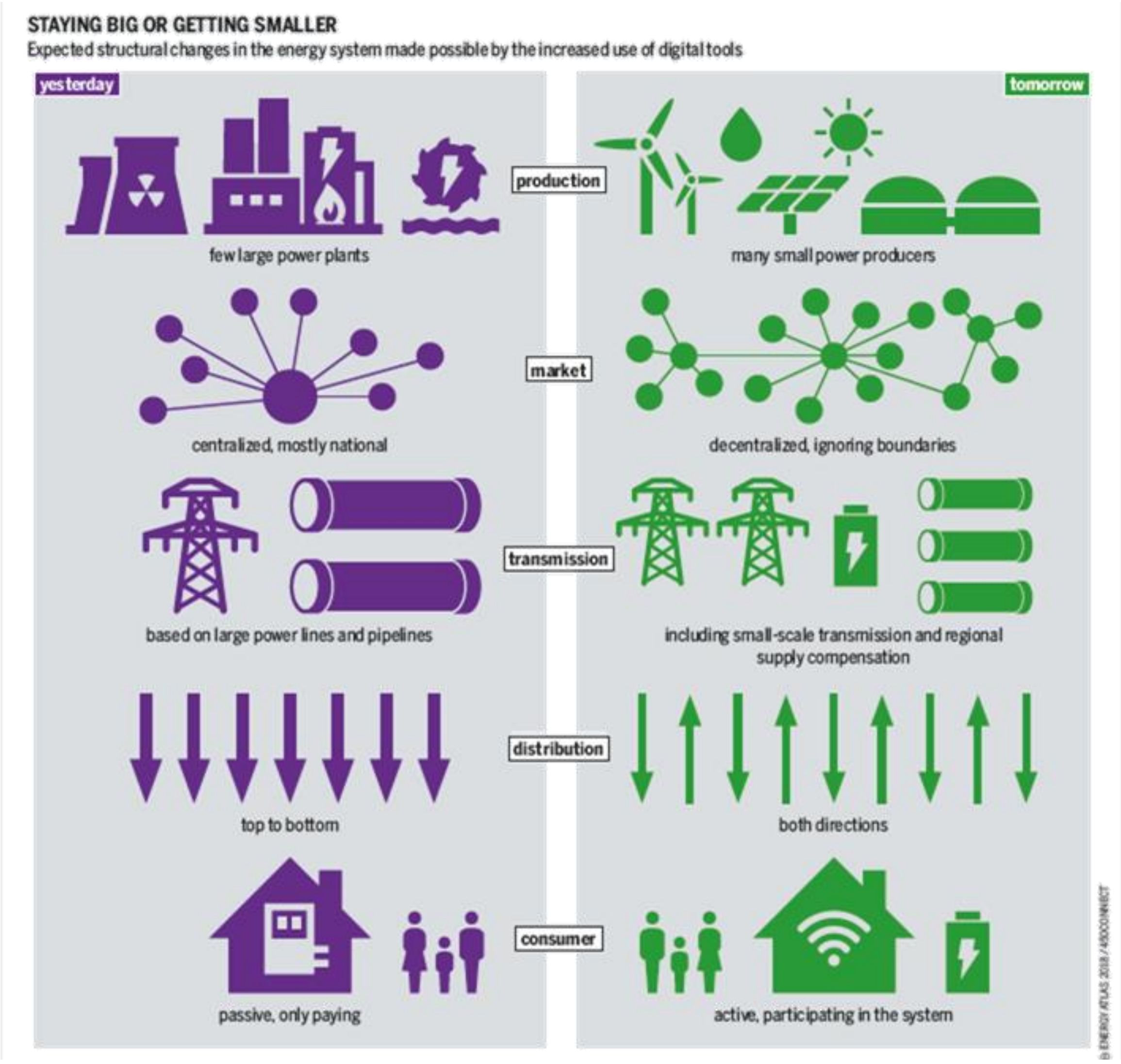


Figure 2.10 - Current structural changes in the energy sector [19]

Therefore, new transmission lines will be required in certain areas, but with the adoption of distributed generation, smart grids, flexible demand and storage systems the investment needed will be much lower. Interestingly enough, the mojority of these technologies and strategies will be participated, owned and managed by citizens that, once again, will be at the centre of the energy transition and will be the key to guarantee the flexibility that the system will require.

According to the 2020 study "*Comunità Rinnovabili*" by Legambiente [14], Italy is already undergoing such transformation, even though at a lower rate with respect to other European countries. If in 2005 only 356 municipalities had electric and thermal plants installed in their territories, in 2019 the number increased up to 7911, which is the totality of the municipalities in Italy (Figure 2.11). In particular, 7766 municipalities have at least one PV plant, 7223 at least one solar thermal, 1489 especially in the North one mini-hydroelectric, 1049 mainly in the South one wind plant, 3616 one bioenergy and 594 one geothermal plant (Table 2.2). Moreover, in 3300 municipalities the annual electricity production overcomes the demand, whereas 567 municipalities can satisfy between 70 and 99% of their electricity demand and 568 between 50 and 69%. Lastly, in 41 municipalities 100% of the thermal and power demand is covered by renewable, meaning that their generation mix is such that they are completely autonomous and self-sufficient as the production by renewable sources overcomes the total needs by the citizens for both electrical and thermal energies (Figure 2.12).

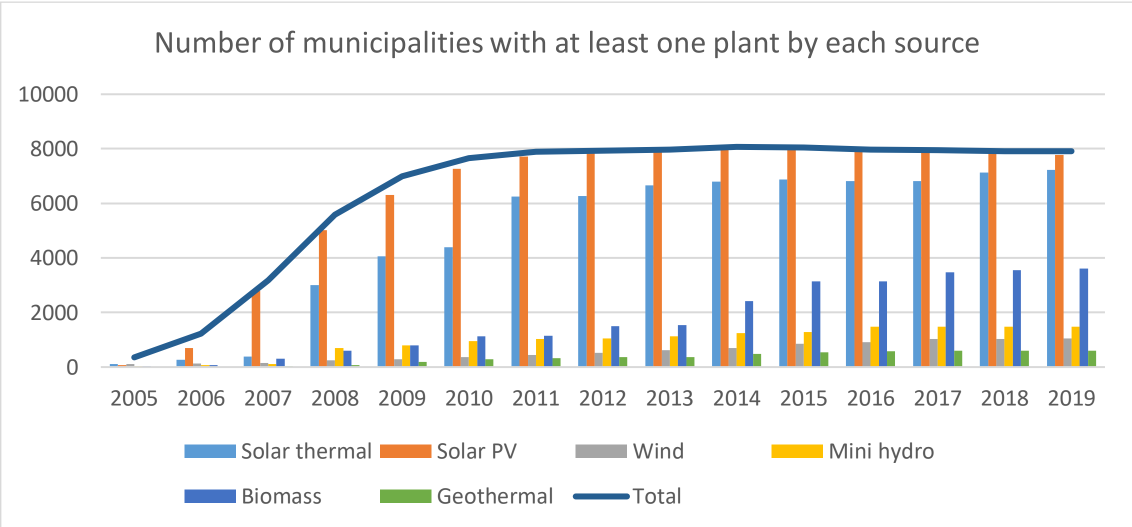


Figure 2.11 - Distributed generation in Italian mucnicipalities [14]

Table 2.2 - Number of municipalities with at least one plant by each source [14]

	Solar thermal	Solar PV	Wind	Mini hydro	Biomass	Geothermal	Total*
2005	108	74	118	40	32	5	356
2006	268	696	136	76	73	9	1232
2007	390	2799	157	114	306	28	3190
2008	2996	5025	248	698	604	73	5591
2009	4064	6311	297	799	788	181	6993
2010	4384	7273	374	946	1136	290	7661
2011	6256	7708	450	1021	1140	334	7896

2012	6260	7854	517	1053	1494	360	7937
2013	6652	7906	628	1123	1529	372	7964
2014	6803	8047	700	1250	2415	484	8071
2015	6882	8047	850	1275	3137	535	8047
2016	6820	7978	904	1489	3144	590	7978
2017	6822	7862	1025	1489	3467	595	7954
2018	7121	7839	1028	1489	3560	598	7915
2019	7223	7776	1049	1489	3616	594	7911

* The last column "Total" is not the sum of the row but rather the total number of municipalities with at least one plant of whatever source, meaning that a municipality can have one or more plants of each source but still be counted as one in the total number of municipalities.

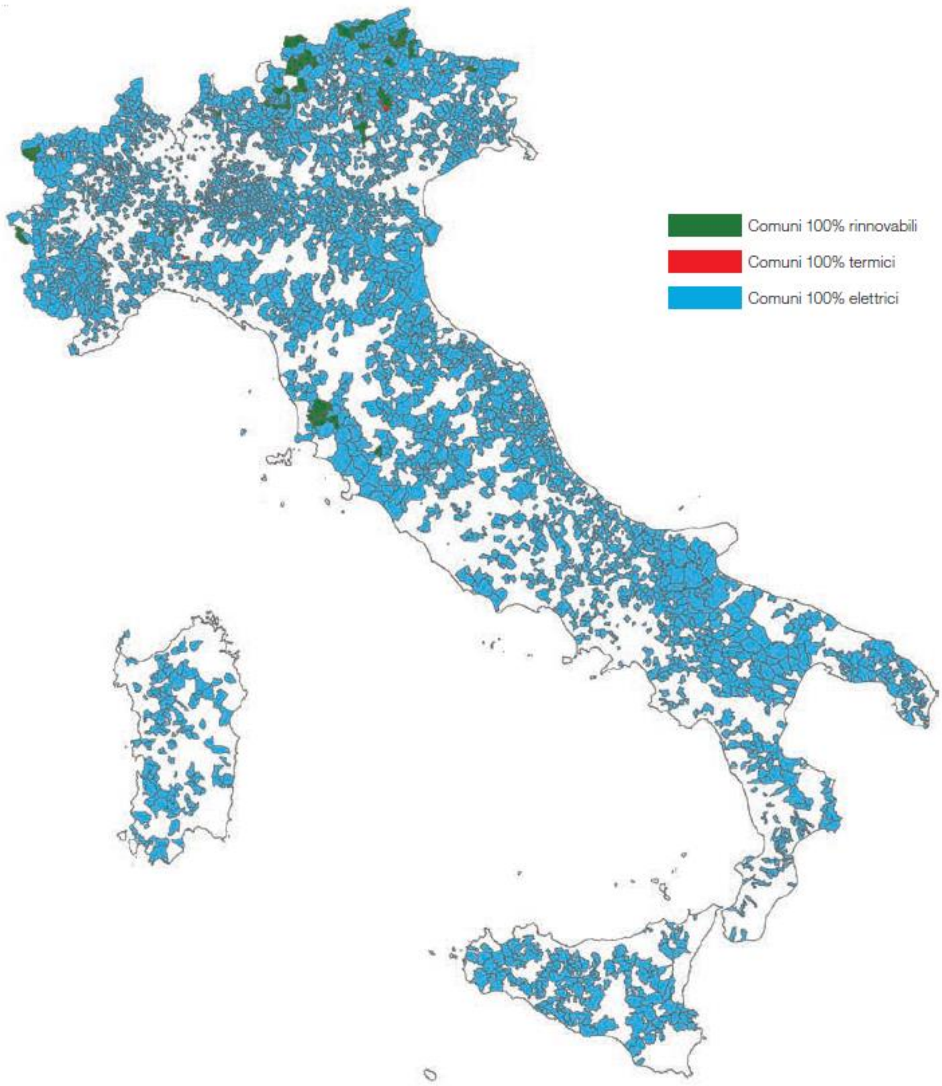


Figure 2.12 - Distribution of energy self-sufficient municipalities in Italy [14]

2.2 Electrification through heat pumps

Heat pumps (HPs) are considered the key and most efficient technology to electrify and decarbonise heat. According to the IEA, in fact, if heat pumps gained a 30% market share at global scale, they would cut global CO_2 emissions by 8% or 1.8 Gton annually, which is the largest contribution to global GHG mitigation possibly made by a single technology [25].

The underlying principle of a heat pump is that of a reverse cycle, as it uses mechanical work to move heat against its natural gradient from a cold location to a hotter one (Figure 2.13) [25]. The basic design has undergone successive improvements with the introduction of rotary vanes, two-stage configurations and inverters to modulate the compressor speed and vary the heating power provided, but the main components remain the compressor unit, the internal heat exchanger, the expansion valve and the external heat exchanger. Most heat pumps, moreover, are now capable of working as air conditioners by reversing the direction of refrigerant flow and providing not only heating but also cooling power.

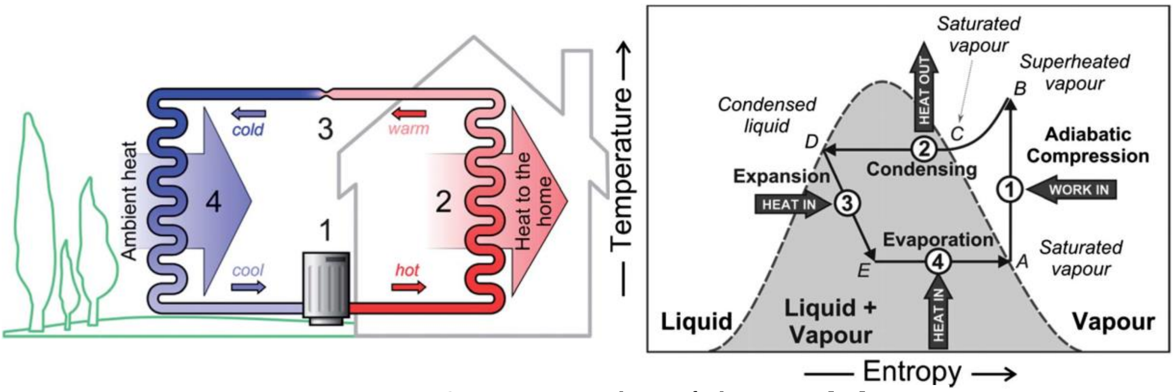


Figure 2.13 - Functioning scheme of a heat pump [25]

The efficiency of the process, i.e. the COP, is generally higher than unity because the working fluid is given energy not only through the mechanical work, but also by the external air and, therefore, a typical system can produce 3 MWh of space and water heating from around 1 MWh of electricity, which would otherwise be generated from a higher quantity of primary energy by other traditional sources (Figure 2.14).

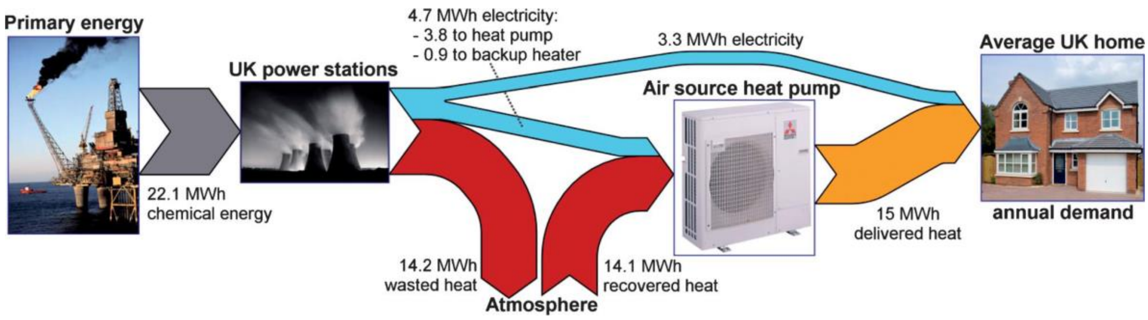


Figure 2.14 - Energy fluxes of a heat pump [25]

HPs can be differentiated according to the heat sink used – the delivery point of the heat, – which usually is a fan-coil unit, radiators or underfloor heating, or can also be distinguished by their application, as they can be used only for heating purposes or for both heating and cooling. The main classification, however, is performed by considering the heat source, that is the source where the heat is collected, according to which at least three categories can be identified:

- Air source heat pumps (ASHPs), whose heat source is air (outside, exhaust or indoor air),
- Water source heat pumps (WSHPs), that draw heat from a water sink (water tables, rivers or lakes), and
- Ground source heat pumps (GSHPs), which extract heat from the ground or groundwater.

ASHPs can use several distribution methods, namely air-to-air and air-to-water systems: the first directly heats the indoor air and most of the times can perform both heating and cooling; the second, on the other hand, is integrated into a hydronic water-based central heating system, that can be the one already installed connected to the previous gas boiler system, to provide whole-house heating plus hot water. Almost all ASHPs operate reversibly, and in countries with hot climates the cooling function is often the main market driver [24]. The main disadvantage of ASHPs, however, is that they are generally less efficient when the outdoor temperature is low and, correspondingly, when the heating demand is higher; in other words, the higher the temperatures difference between the heat source and the heat sink, the lower the performances of the HPs [26].

GSHPs and WSHPs, on the other hand, usually use underfloor piping or low- or high-temperature radiators to distribute the heat at the sink side and tubes buried underground at the source, allowing them to exploit a more temperature-constant source of heat in spite of more expensive costs and difficult installation. Also, their diffusion is limited as not all areas and countries allow the installation of underground pipes because of the characteristics of the land and the environmental regulations covering the use of groundwater. Consequently, GSHPs are expected to have the smallest share of the global diffusion in favour of ASHP, which on the contrary can be installed regardless of the land characteristics [24].

Other configuration like gas engine heat pumps, that use an internal combustion engine to drive the compressor instead of an electric motor, thermally driven heat pumps that exploit absorption and adsorption reactions, and solar assisted heat pumps, that are coupled with a solar thermal plant, exist even beyond the experimental stage, but are not as diffused as the main typologies.

Expectedly, however, as already said in Chapter 2.1, many challenges may rise from the introduction of heat pumps to satisfy the heating needs. First of all, the winter electricity demand will increase: according to Fawcett [32], a global 100% heat pump adoption would require the electricity demand to increase by 11% and the peak demand to increase by 65%.

The latter is the main aspect to take into account when dealing with electrification, as the high cost entailed with it is enough to prevent or delay the diffusion of heat pumps. Of course, however, a 100% HP adoption will never take place as other renewable nonelectric technologies – district heating, biogas and biomass, solar thermal and hybrid systems – will have to obtain a little or high share of the heating demand, according to the local availability and characteristics and as either primary or backup technologies, since it is not verisimilar to imagine a heating sector entirely covered by heat pumps.

Some other aspects, nevertheless, may help reduce the problematics related to the heat pumps diffusion. First, the heating demand usually shows a more predictable trend with respect to the electricity one: this aspect will partially contribute to not increase the unpredictability of the demand as much as its absolute value. Moreover, according to Watson [27], the improvement in the housing stock in terms of efficiency and the shorter heating season due to climate change will decrease the total demand. In spite of this, some other changes in demographics and social habits could actually increase it, such as the aging population and a possible increase of home working. This last aspect, if on one hand causes an increase in the demand, on the other will potentially lead to a more diverse timing of households' morning peak heat demand and a decrease in the maximum morning peak.

2.3 Heat pumps diffusion

The sales data held by EurObserv'ER [24] shows that more than 3.5 million systems were sold in 2017 in the European Union. The main market for ASHPs in 2017 remains that of Italy with the market being driven especially for cooling purposes, with as much as 1.4 million units sold despite its slowdown with respect to 2016, followed by Spain and France (Figure 2.15).

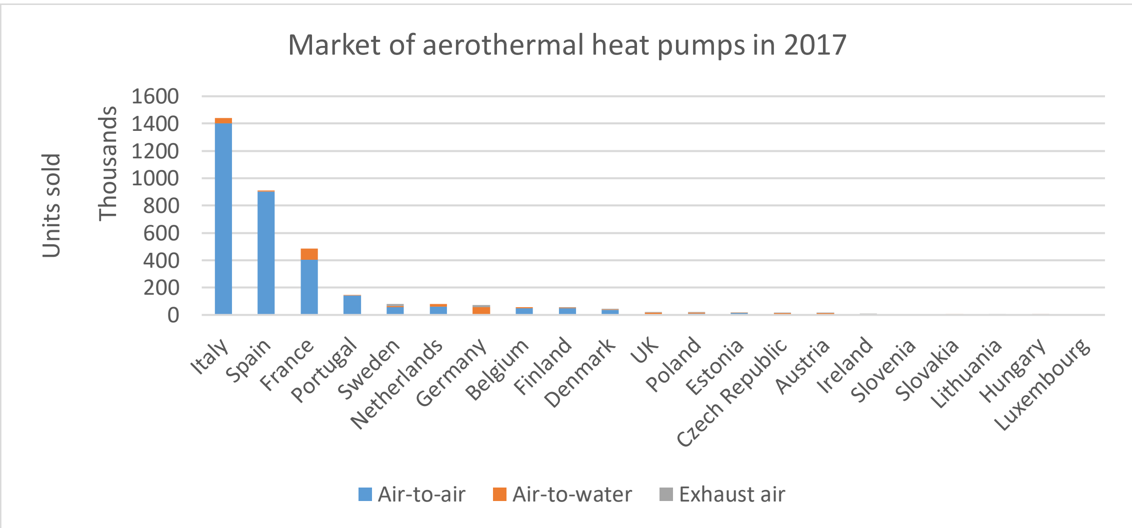


Figure 2.15 - Market of aerothermal heat pumps in EU28 [24]

For what concerns GSHPs and WSHPs, the main market is 2017 is Sweden followed by Germany, while Italy is only in the 13th position. In general, the market has a dimension of two orders of magnitude lower than the one for ASHPs, reflecting the higher investment costs and land requirement connected to this technology (Figure 2.16).

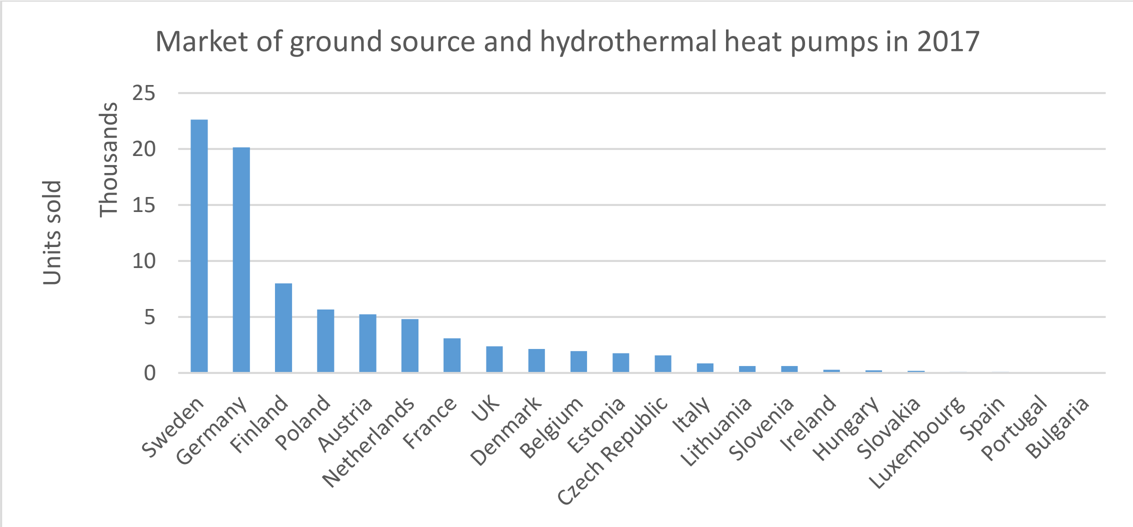


Figure 2.16 - Market of ground source and hydrothermal heat pumps in EU28 [24]

The total number of heat pumps, however, sees firmly Italy in the first position, with a total of almost 20 million units in place, with France and Spain in the second and third positions with slightly more than 5 and about 3 million units, respectively (Figure 2.17).

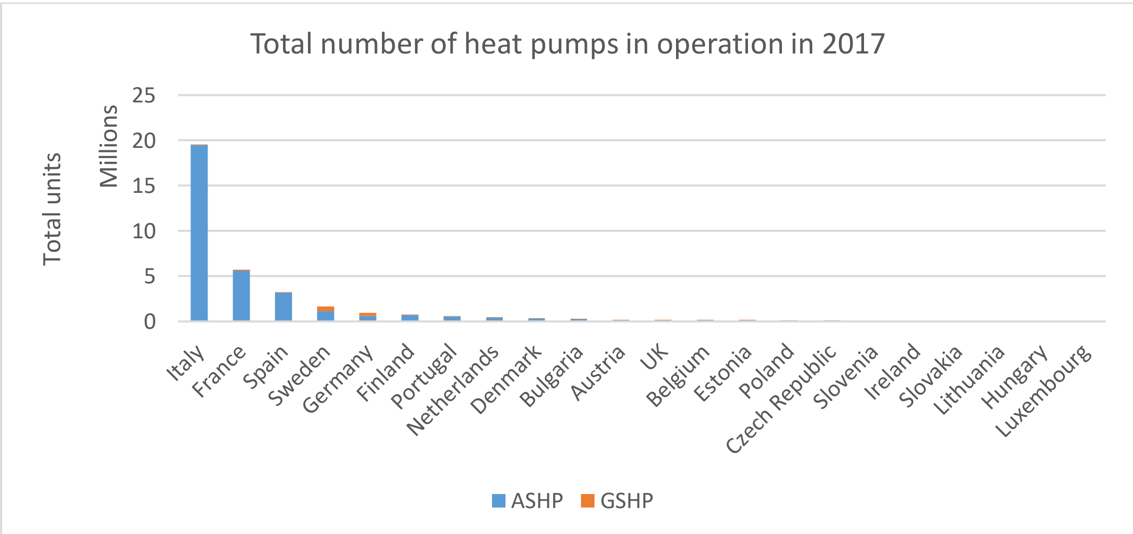


Figure 2.17 - Total number of heat pumps in EU28 [24]

According to the IEA, electric heat pumps still meet less than 5% of heating needs in buildings globally, but their real potential is much greater as they could supply more than

90% of global space and water heating. Italy, in particular, despite being the first market for heat pumps in the entire EU28, has not reached its full potential for the heat pumps diffusion yet and its penetration index is considerably lower with respect to the best-performing countries [26]. The majority of the regions, in fact, still sees a thermal energy demand covered by traditional fuels such as methane, LPG or biomass. According to Pieve [26], among the main barriers for their diffusion the energy prices, policy measures, incentives and developments in the building sector all play a significant role, as well as the lack of awareness in the supply chain, for which often the installer does not know the advantages of HPs or does not promote them adequately.

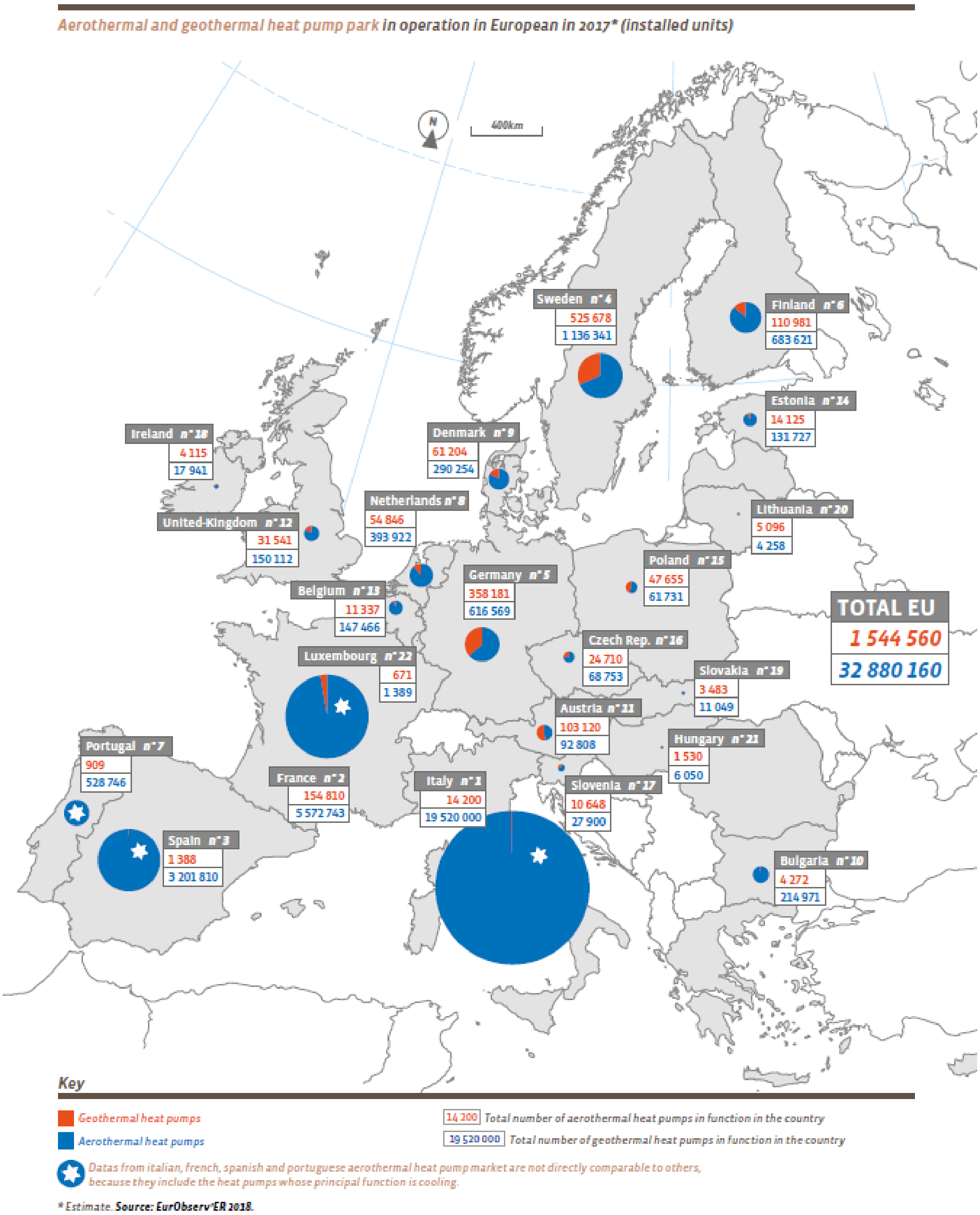


Figure 2.18 – Comparison of heat pumps diffusion in EU28 [24]

Chapter 3
Energy Communities

The model simulates the introduction of an energy community in an area. This chapter illustrates the European normative considering both the Renewable and Electricity Directives of the Clean Energy Package and highlighting the differences between "renewable energy communities" and "citizen energy communities". The National definition of energy community by the Italian government transposition of the Renewable Directive is also introduced, as well as the related existing or planned projects. Lastly, their diffusion potential in EU28 is unfolded.

3.1 Overview

An energy community is an emerging concept formally introduced with the Clean Energy Package. In general, it is a legal entity where citizens, SMEs and local authorities self-organise in a way such that they cooperate in an energy-related activity based on open and democratic participation and governance, the primary purpose of which is to engage in an economic activity with non-commercial aims that provides benefits to the members and to the local community [6].

To deepen this definition, energy communities can perform activities across the energy sector, including renewable energy generation, provision of energy efficiency services, buildings renovations, retail supply, distribution of heat and electricity, storage, flexibility services, aggregation, and electro-mobility services [6]. Moreover, they are based on a number of principles, among which:

- Supply of local, distributed and sustainable energy;
- Open and voluntary participation;
- Direct and democratic governance based on equal decision-making rights;
- Autonomy, being that the decision making by one or a small group of individual members does not overtake the collective will of the members;
- Ownership and control, being that the undertaking is controlled by the members or shareholders who are participating as final users, while outside investors do not have a controlling position.

For what concern the purpose that energy communities should pursue, it is the provision of benefits for the entire community rather than financial profits. This means that while some return on investment to members can exist, the generation of revenues from the community's activities should be used to provide services to the members, to reduce energy bills or to invest in local socio-economic initiatives.

Moreover, in spite of the upfront investment costs, the necessary local engagement, the dependence on non-energy professionals and the lack of experience in the bureaucracy to access this new legal entity, energy communities provide citizens a number of benefits that other market actors cannot [6], such as:

- A fair and affordable access to local and clean renewable energy sources;
- The control and responsibility for the self-provision of their energy needs, furthering energy democracy;
- Investment opportunities for citizens and local businesses;
- The ability to generate revenue that stays in the local economy to address socio-economic needs of the community;
- Public acceptance of renewables by allowing citizens to invest and participate in the decision making of the project.

Lastly, energy communities offer benefits for the energy system since they can help DSOs operate their networks more flexibly, safely and efficiently thanks to storage systems, including batteries and electric vehicles, and demand response systems [38] such as peak shavings – used to shave the demand peaks, – power ramp rate reductions – that smooth the fluctuating behaviour of the power produced by intermittent renewable sources – and backup energy – activated in case of grid failures or disconnection from the grid.

3.2 Clean Energy Package (CEP)

The final Clean Energy Package (CEP) contains two definitions of energy community: "Renewable Energy Community", which is contained in Directive EU/2018/2001 (Renewable Energy Directive) [1] – already transposed, even though in a temporary and partial way still to be updated, into National Law by the Italian government with Law 28 February 2020, n. 8 [16], – and "Citizen Energy Community", which is contained in Directive EU/2019/944 [2] (Electricity Directive). The two definitions are similar but differ for some aspects.

More specifically and following the good explanation about the distinction between the two definitions made by REScoop [6], according to the Renewable Energy Directive EU/2018/2001, Article 2, Comma 16,

> *'renewable energy community' means a legal entity:*
>
> *(a) which, in accordance with the applicable national law, is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders*

or members that are located in the proximity of the renewable energy projects that are owned and developed by that legal entity;

(b) the shareholders or members of which are natural persons, SMEs or local authorities, including municipalities;

(c) the primary purpose of which is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits.

On the other hand, according to the Electricity Directive EU/2019/944, Article 2, Comma 11,

'citizen energy community' means a legal entity that:

(a) is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises;

(b) has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits; and

(c) may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders.

The two definitions have some recurrent characteristics, i.e. the open and voluntary participation, the effective control placed on citizens, local authorities and smaller businesses that are not already active in the energy sector, and finally the provision of environmental, economic and/or social community benefits for its members or the local areas rather than financial profits. However, some important differences are also present that define their peculiarities: for the eligibility, only natural persons, local authorities and micro or small enterprises can participate in a citizen energy community, while renewable energy communities allow medium sized enterprises to join too; the effective control of citizen energy communities is to natural persons, local authorities or micro- and small enterprises, whereas renewable energy communities must be effectively controlled by members that are located in proximity of the community's projects, without any reference to size; lastly for the autonomy, the internal decision making of renewable energy communities must be autonomous from individual members and other market actors that participate in the community as members or shareholders, whereas on the citizen energy communities side no information about autonomy is mentioned [6].

Moreover, renewable energy communities focus only on renewable energy, as stated by Article 22, Comma 2 of the Renewable Energy Directive:

[Member States shall ensure that renewable energy communities are entitled to] (a) produce, consume, store and sell renewable energy, including through renewables

> *power purchase agreements; (b) share, within the renewable energy community, renewable energy that is produced by the production units owned by that renewable energy community, subject to the other requirements laid down in this Article and to maintaining the rights and obligations of the renewable energy community members as customers.*

On the other hand, the activities in which citizen energy communities operate are related to the electricity sector, as affirmed by Article 16, Comma 3 of the Electricity Directive:

> *[Member States shall ensure that citizen energy communities] are entitled to arrange within the citizen energy community the sharing of electricity that is produced by the production units owned by the community, subject to other requirements laid down in this Article and subject to the community members retaining their rights and obligations as final customers.*

In Table 3.1 are reported the main differences between the two definitions.

Table 3.1 - Differences between Renewable and Citizen Energy Communities [6]

	Renewable Energy Communities (Renewables Directive)	**Citizen Energy Communities (Electricity Directive)**
Open & Voluntary Membership	"*A legal entity which, in accordance with the applicable national law, is based on open and voluntary participation*" (Article 2, Comma 16)	"*A legal entity that is based on open and voluntary participation*" (Article 2, Comma 11)
Eligibility	"*The shareholders or members of which are natural persons, SMEs or local authorities, including municipalities*" (Article 2, Comma 16)	"*Effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises*" (Article 2, Comma 11)
Autonomy	"*A legal entity which, in accordance with the applicable national law, is autonomous*" (Article 2, Comma 16)	No autonomy principle
Democratic Governance & Ownership	"*A legal entity which, in accordance with the applicable national law, is effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and*	"*A legal entity that is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises*" (Article 2, Comma 11)

	developed by the legal entity" (Article 2, Comma 16)	
Purpose	"*The primary purpose of which is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits*" (Article 2, Comma 16)	"*A legal entity that has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits*" (Article 2, Comma 11)
Activities	"*Member States shall ensure that renewable energy communities are entitled to: (a) produce, consume, store and sell renewable energy, including through renewables power purchase agreements; (b) share, within the renewable energy community, renewable energy that is produced by the production units owned by that renewable energy community, subject to the other requirements laid down in this Article and to maintaining the rights and obligations of the renewable energy community members as customers; (c) access all suitable energy markets both directly or through aggregation in a non-discriminatory manner.*" (Article 22, Comma 2)	"*A legal entity that may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders*" (Article 2, Comma 11)

Moreover, there are some other differences regarding the active involvement of the Member States. In particular, the Electricity Directive guarantees that citizen energy communities can participate in the electricity market without discrimination, but it does not require Member States to actively promote their development. On the contrary, the Renewable Energy Directive also prevents discrimination, but it even goes further and requires Member States to take actions to promote the development of renewable energy communities, especially through information campaigns addressed to the citizens. This is all affirmed by Article 22, Comma 3 and Comma 4 of the Renewable Energy Directive:

3. Member States shall carry out an assessment of the existing barriers and potential of development of renewable energy communities in their territories.

4. Member States shall provide an enabling framework to promote and facilitate the development of renewable energy communities. That framework shall ensure, inter alia, that:

(a) unjustified regulatory and administrative barriers to renewable energy communities are removed;

(b) renewable energy communities that supply energy or provide aggregation or other commercial energy services are subject to the provisions relevant for such activities;

(c) the relevant distribution system operator cooperates with renewable energy communities to facilitate energy transfers within renewable energy communities;

(d) renewable energy communities are subject to fair, proportionate and transparent procedures, including registration and licensing procedures, and cost-reflective network charges, as well as relevant charges, levies and taxes, ensuring that they contribute, in an adequate, fair and balanced way, to the overall cost sharing of the system in line with a transparent cost-benefit analysis of distributed energy sources developed by the national competent authorities;

(e) renewable energy communities are not subject to discriminatory treatment with regard to their activities, rights and obligations as final customers, producers, suppliers, distribution system operators, or as other market participants;

(f) the participation in the renewable energy communities is accessible to all consumers, including those in low-income or vulnerable households;

(g) tools to facilitate access to finance and information are available;

(h) regulatory and capacity-building support is provided to public authorities in enabling and setting up renewable energy communities, and in helping authorities to participate directly;

(i) rules to secure the equal and non-discriminatory treatment of consumers that participate in the renewable energy community are in place.

Table 3.2 by the 2019 report “Energy Communities in the European Union” by ASSET [8], summarizes the main differences between the two definitions.

Table 3.2 - Summary of the differences between Renewable and Citizen Energy Communities [8]

	Renewable Energy Community	**Citizen Energy Community**
Legal entity	✓	✓
Voluntary membership	✓	✓

Specific governance	✓ (effectively controlled by members/shareholders)	✓ (effectively controlled by members/shareholders)
Collective action in the energy field	✓	✓
Members	Natural persons, local authorities including municipalities, SMEs	Natural persons, local authorities including municipalities, small and micro-enterprises
Locational limitation	✓ (local proximity)	
Type of energy	All RES	Electricity only
Technology neutral	No (only RES)	✓
Purpose	Provide environmental, economic or social community benefits for its shareholders/members or the local areas where it operates rather than financial profits	Provide environmental, economic or social community benefits for its members or the local areas where it operates rather than financial profits
Activities	Producing, consuming, storing and selling renewable energy	Electricity generation, distribution and supply, consumption, aggregation, storage, energy efficiency services, generation of renewable electricity, charging services for electric vehicles, other energy services
- Renewable electricity	✓	✓
- Non-renewable electricity		✓
- Renewable heat	✓	
- Renewable transport	✓	
- Energy sharing	✓	✓

- Distribution		✓
- Supply		✓
- Balancing responsibility	✓	✓
- Consumption of energy	✓	✓
- Aggregation		✓
- Energy storage	✓	✓
- Efficiency services		✓
- EV charging		✓
- Energy services		✓
- Sales of energy	✓	
Market access	✓	✓
Non-discrimination	✓	✓
Consumer protection	✓	✓
Support provisions	✓	
DSO status		✓
Cross-border participation	✓	✓

3.3 Italian case

Proceeding the Clean Energy Package, Member States are required to transpose the directives into national laws by 30 June 2021, developing their national definitions for energy communities and enabling them to participate in the energy system. After a first introduction of the energy communities contained in the PNIEC, the Italian government has temporarily and partially transposed the Renewable Energy Directive EU/2018/2001 with Law "*Conversione in legge, con modificazioni, del decreto legge 30 dicembre 2019, n. 162, recante disposizioni urgenti in materia di proroga di termini legislativi, di organizzazione delle pubbliche amministrazioni, nonché di innovazione tecnologica.*" (Legge 28 febbraio

2020, n. 8), following the "*Milleproroghe*" decree n. 162 of 30 dicembre 2019 (DL n. 162 30 dicembre 2019), therefore basing this first definition of energy communities on the Renewable Energy Community rather than the Citizen Energy Community [16].

According to the National law and similarly to the Renewable Directive, energy communities in Italy are based on a number of principles:

- The energy-related activities do not constitute the main commercial or professional activity (Art. 42-bis, comma 3, letter a);
- The shareholders or members are natural persons, small and medium-sized enterprises, local or regional authorities including municipal administrations (Art. 42-bis, comma 3, letter b);
- The main objective is to provide environmental, economic or social benefits at the community level to its shareholders or members or to the local areas in which the community operates, rather than financial profits (Art. 42-bis, comma 3, letter c);
- The participation is open to all consumers located within the perimeter defined by the transformer substation, such that the consumer withdrawal points and the points of entry of the plants are located on low voltage electricity grids underlying the same medium voltage/low voltage transformer substation (Art. 42-bis, comma 3, letter d);
- The overall power capacity of the installed plants does not exceed 200 kW (Art. 42-bis, comma 4, letter a);
- They can access an incentive rate provided by GSE Spa aimed at rewarding the instant self-consumption and the use of storage systems (Art. 42-bis, comma 9).

It is important to highlight, however, that the National law is just a first step in the transposition of the Clean Energy Package and new laws and decrees will eventually be published to clarify and/or revise some aspects and foster even more the diffusion of the energy communities in the country. This is in fact very probable because of at least three reasons: first, the transposition into national law by Legge 28 febbraio 2020, n. 8 has only an experimental configuration, where the maximum power to install is limited to 200 kW and the temporal validity of such normative is limited to be within 60 days from the transposition of the directive, planned in June 30th, 2021; second, the incentive that, according to the same Law, should be provided by GSE to remunerate the instant self-consumption has still to be defined, and it is quite probable that it will partially change the diffusion potential of energy communities and their normative definitions; lastly, Legge 28 febbraio 2020, n. 8 was promulgated to transpose the EU Renewable Directive into National law, whereas the Electricity Directive containing the citizen energy community concept still has to be transposed, after which the definition of energy community will, once again, be eventually partially changed.

The case of Italy is particular, as the exchange of energy among citizens in the form of cooperatives was already present in the historical cooperatives that survived the nationalization of the electricity system in the '60s. The innovation, for this reason, is not about the energy communities themselves but rather for what concerns the possibility for citizens, households, public and industrial buildings to participate and join the transformation too in the form of new energy communities. In fact, according to the 2020 study “Comunità rinnovabili” by Legambiente [14], there exist at least 12 completed or planned projects of energy communities in Italy, some of which are those existing historical cooperatives and some others are new projects that will make use of the recent published normative (Table 3.3).

Figure 3.1 - Geographic distribution of existing (historical cooperatives) or planned projects about community energy in Italy* [14]

* Please refer to Table 3.3, notice that the energy communities only are considered, whereas the other numbers refer to self-consumption projects.

Table 3.3 – List of existing (historical cooperatives) or planned projects about community energy in Italy [14]

1	Comunità energetica del Pinerolese
2	Comunità energetica di Primiero-Vanoi
3	Comunità energetica di Roseto Valfortore
4	Comunità energetica Alpina di Tirano
5	Comunità energetica della Valle Susa (CEVS)
6	Energia agricola a Km 0: la comunità energetica agricola del Veneto
7	GECO - Green Energy Community
8	PAN- Puglia Active Network
9	Smartgrid di Berchidda
10	Progetto BloRin
11	Comunità energetica di Prato allo Stelvio
12	Società Elettrica Cooperativa dell'Alto But - S.E.C.A.B.

3.4 Energy communities potential

Two studies have been identified to be the most significant for estimating the potential of the energy communities. The first, "I prosumer condominiali" by Elemens, RSE, Kantar and Energy@Home [13], estimates at about 2.6 millions the households in Italy that may be eventually interested in installing a PV system on their roofs, reaching as much as 29 GW at Italian level by PV and a saving from 1.4 to 2 billion €. The second, on the other hand, "The potential of energy citizens in the European Union" made by CE Delft in 2016 and commissioned by Greenpeace, Friends of the Earth Europe, European Renewable Energy Federation (EREF) and REScoop [12], focusses on the concepts of "*energy citizen*" and "*prosumer*" that indicate individuals, households, public or private companies that move from being only energy consumers to also actively take part in the energy system, either by producing energy or by providing flexible demand and energy storage. The findings are subject to many uncertainties as the research on this topic and the data were still limited but, in spite of this, the results can be used as a first indicator of the real potential of energy communities in the EU. First of all, a number of assumptions, data and forecasts are introduced in the model:

- Four energy citizen categories are identified – i.e. individuals or households producing energy individually, individuals or households producing energy collectively, public entities including cities and municipal buildings, schools, hospitals, government buildings, and small enterprises;

- The policy and regulatory barriers are assumed to be removed over time, and the national grids, distribution networks and electricity markets are developed in parallel with the growth of renewable energy production, demand side flexibility and storage options;
- The "Greenpeace Energy [R]evolution" scenario is used as a framework that models a global energy system based entirely on renewable energy in 2050;
- Solar PV and wind power for renewable energy production and stationary batteries, smart electric boilers and electric vehicles for flexible demand and storage options are considered;
- The positive externalities in economic, environmental and societal terms – for example the reduction of peak loads on grid, the reduction of the need for backup capacity in times of low RES production, or the flexibility that allows the energy citizen to benefit from periods of low electricity price in times of high solar and wind generation – are not considered for simplicity.

Starting from this input data and assumptions, the research shows that the potential for citizen-owned renewable energy projects in Europe amounts at 264 million "energy citizens" – half of all European Union population – that could generate 45% of the European Union's electricity needs by 2050. According to the study, the majority of the electricity production by solar PV is likely to come from households, followed by citizen collectives, while, for wind, enterprises account for almost two thirds of the total electricity production with the rest covered by collectives (Figure 3.2).

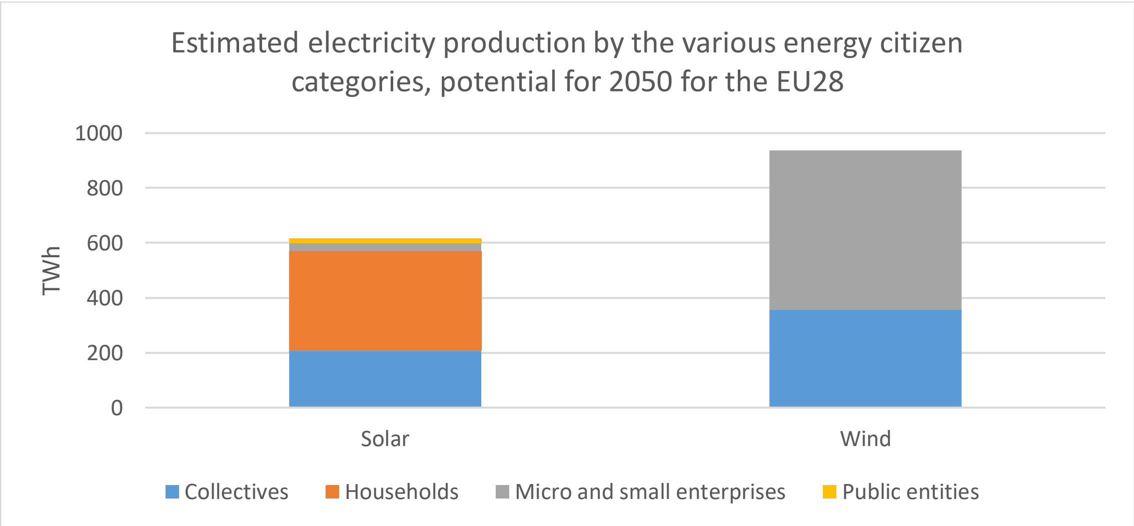


Figure 3.2 - Potential electricity production by energy citizens in EU28 [12]

The study analyses also the potential ownership for each technology. Households have the greatest share for all technologies and, for electric boilers and electric vehicles, account for almost 100% of the installations. For solar, wind and stationary batteries, on the other hand, collectives are expected to own a large part of the installations (Figure 3.3).

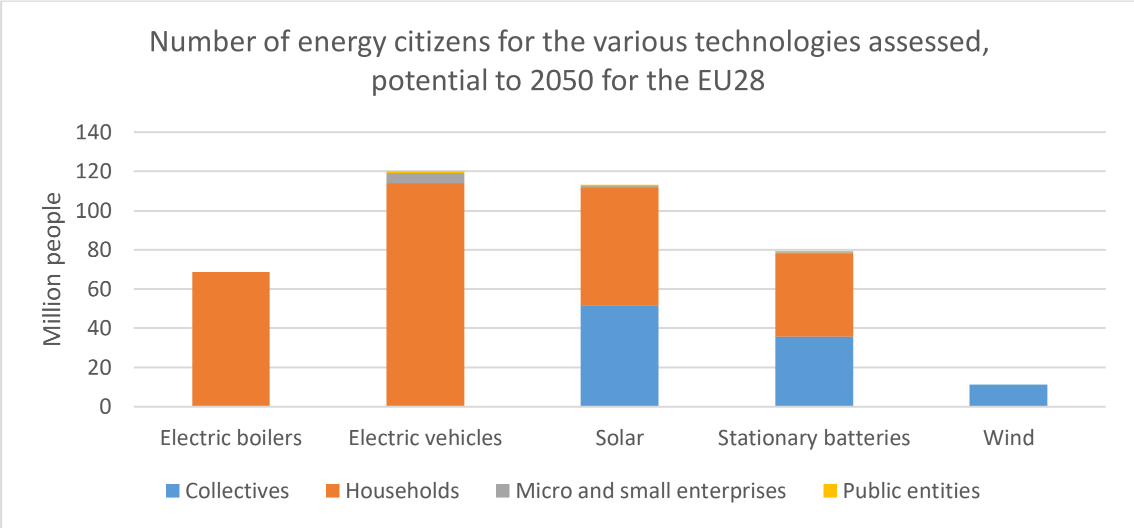


Figure 3.3 - Potential number of energy citizens in EU28 [12]

Then, the potential storage capacity is also taken into account and is estimated to reach almost 2000 GWh by 2030 and exceed 10,000 GWh by 2050. Of this amount, electric vehicles are expected to represent the lion's share of the additional capacity, followed by stationary batteries and electric boilers (Figure 3.4).

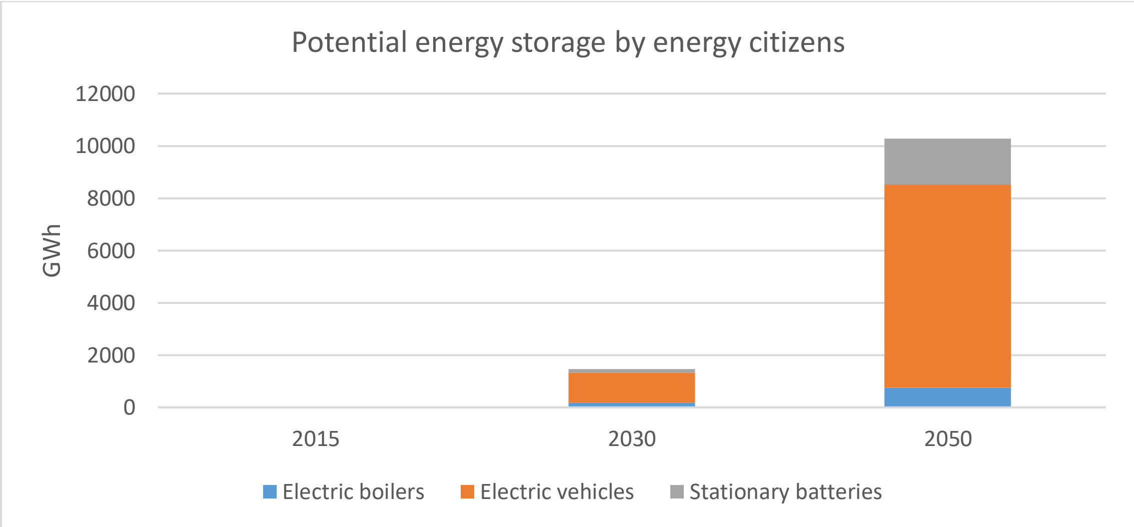


Figure 3.4 - Potential storage capacity by energy citizens in EU28 [12]

Lastly, the potential by each Member State is also analysed. Germany, France, UK, Spain, Italy and Sweden are the countries with the highest potential for the electricity production by energy citizens in absolute terms, reaching as much as 300 TWh for Germany, 250 TWh for France and about 122 TWh for Italy (Figure 3.5).

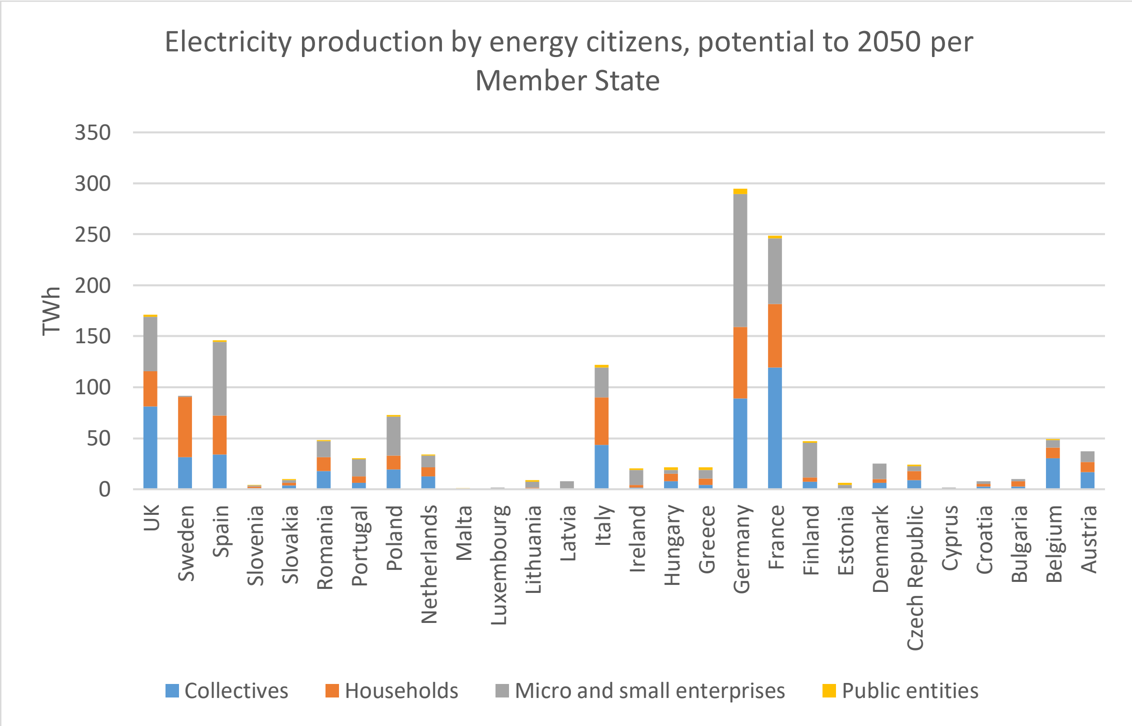


Figure 3.5 - Potential electricity production by energy citizens per Member State [12]

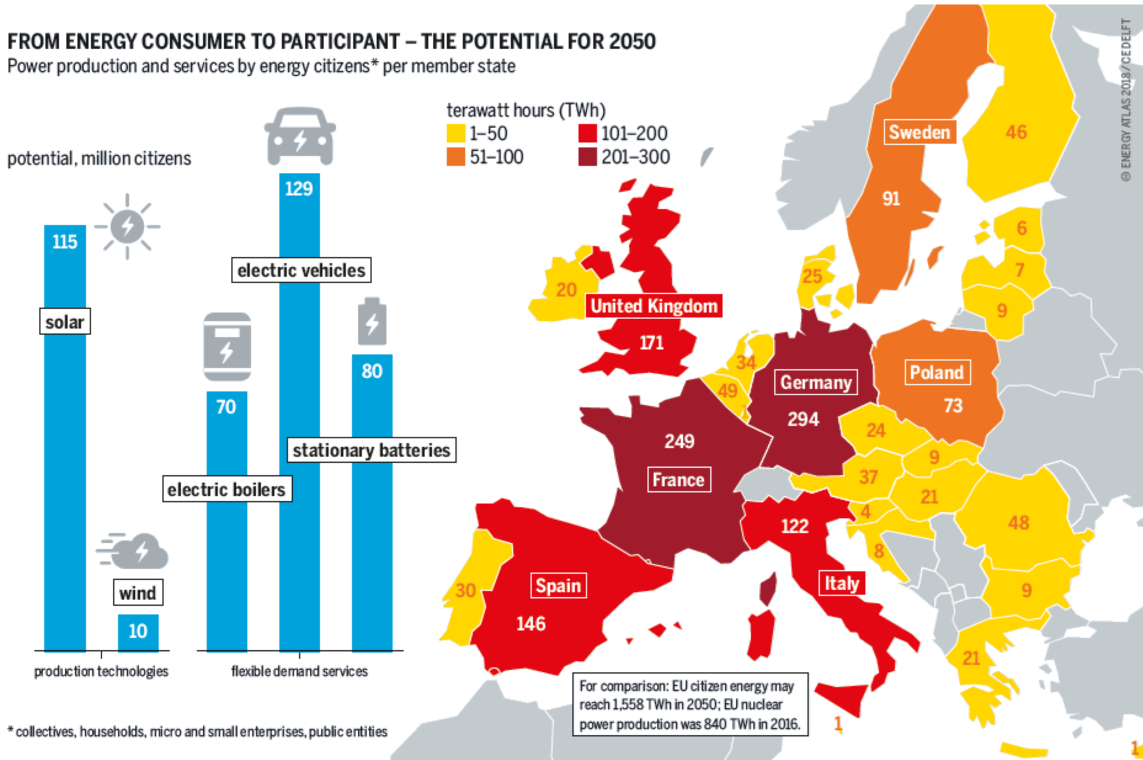


Figure 3.6 - Summary of potential electricity production and storage by energy citizens in EU28 [19]

However, when considering the electricity production with respect to the total electricity consumption (data of 2018), Latvia is shown to exceed the 120% of the total consumption just by energy citizens and Romania to almost reach 100%, meaning that the energy citizens could eventually cover the entire demand and even sell the surplus. For what concerns Italy, energy citizens could cover about 40% of the demand (Figure 3.7).

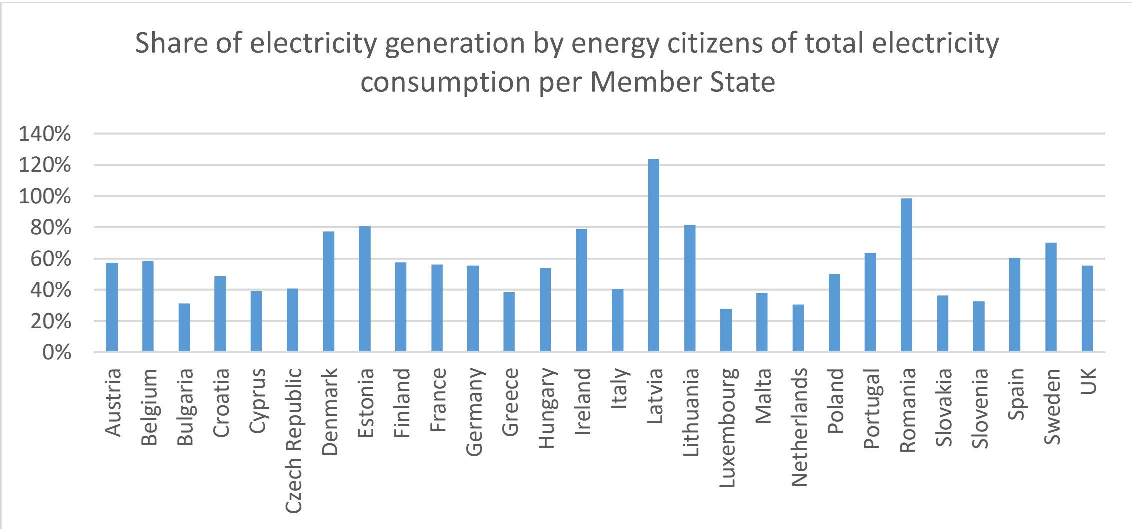


Figure 3.7 - Potential electricity production as share of total consumption per Member State (calculations starting from [12])

Finally, the electricity generation by energy citizens in per capita dimension is also shown for each Member State. Sweden and Finland are estimated to be the countries with the highest per capita generation, exceeding 8 MWh per year, about four times the per capita production in Italy (Figure 3.8).

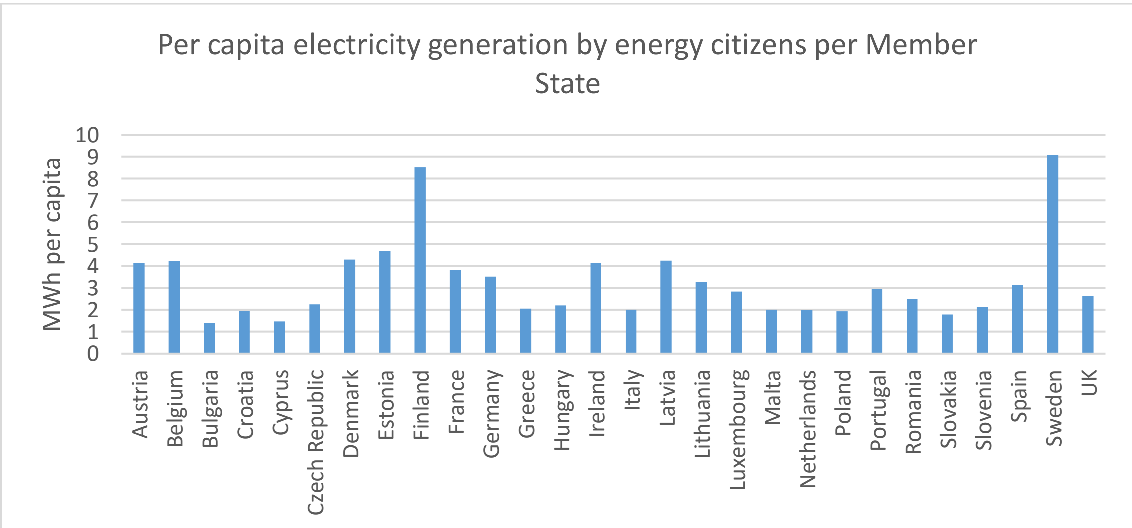


Figure 3.8 - Potential per capita electricity production by energy citizens per Member State (calculations starting from [12])

The purpose of this thesis is to evaluate how the energy community in a certain area should be directed according to the objectives of the policy maker. Together with the current electricity demand, new loads are given to the energy community by the electrification of heating, according to the current electrification strategies at European and National level described in Chapter 2. The objectives pursued by the policy maker and by the energy community, which will be described in Chapter 5, are merged in a multi-objective problem solved by means of existing multi-objective optimization techniques. The next chapter, Chapter 4, mathematically formalizes these techniques and gives examples of application by real cases.

Chapter 4
Multi-Objective Problem

The energy planning is inherently characterized by multiple and diverse objectives, as the energy security must be guaranteed and the energy strategy of the country must be pursued while considering social, economic and environmental issues and objectives at the same time, often finding them to be conflicting to each other. Therefore, multi-objective optimization methods can constitute a technical solution to deal with real-world challenges in the energy context as well. In this chapter the multi-objective problems are mathematically formalized, with a focus on the most diffused techniques currently in use – the global criterion, the weighted sum methodology and the ε-constraints method – with examples of applications by real cases.

4.1 Single-objective optimization

Multi-objective problems are a set of two or more single-objective problems. Therefore, it is useful to mathematically define what the single-optimization ones are first. According to Chiandussi et al. [46], the single-objective optimization problem is defined as the minimization of a scalar objective function

$$f(x)$$

subject to m inequality constraints with $i = \{1, \dots, m\}$

$$g_i(x) \leq 0$$

and p equality constraints with $j = \{1, \dots, p\}$ and $p < n$ to prevent the problem from being over-constrained

$$h_j(x) = 0$$

where x is a n-dimensional decision variable vector

$$x = \{x_1, \dots, x_n\}$$

from some universe Ω that contains all the possible x that can be used to satisfy an evaluation of $f(x)$ and its constraints. The method for finding the global minimum of any function is called the global optimization problem for a single-objective problem. Therefore, given a function

$$f: \Omega \subseteq \mathbb{R}^n \to R$$

with $\Omega \neq 0$, for $x \in \Omega$ the value $f^* \triangleq f(x^*) > -\infty$ is called the global minimum if and only if

$$\forall x \in \Omega: f(x^*) \leq f(x)$$

where x^* is by definition the global minimum solution, f the objective function and Ω the feasible region of x.

4.2 Multi-objective optimization

According to Chiandussi et al. [46], the multi-objective optimization problem (also called multi-criteria optimization, multi-performance or vector optimization problem) can be defined as the problem of finding ”a vector of decision variables which satisfies constraints and optimizes a vector function whose elements represent the objective functions. […] Hence, the term ‘optimize’ means finding such a solution which would give the values of all the objective functions acceptable to the decision maker”.

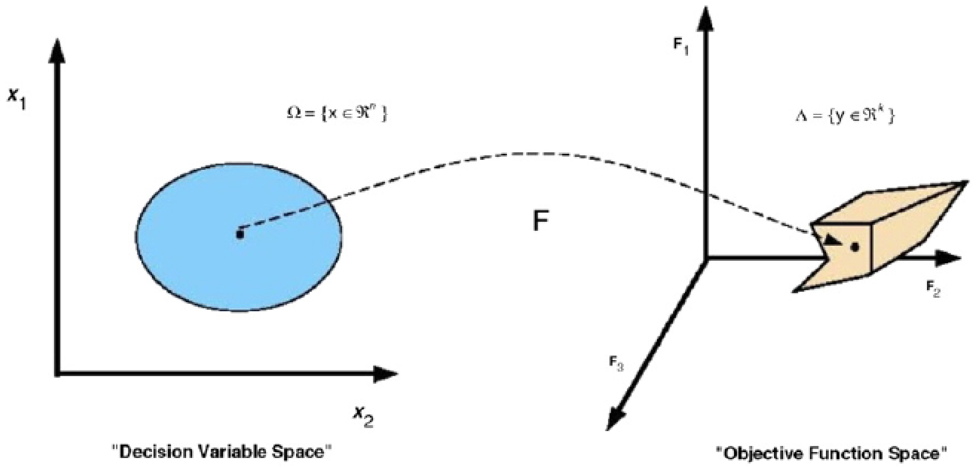


Figure 4.1 - Visual representation of a multi-objective function [46]

Multi-objective optimization problems are, therefore, those problems where the goal is to optimize simultaneously k objective functions $f_1(x)$, $f_2(x)$, ..., $f_k(x)$ forming a vector $F(x)$:

$$F(x) = \begin{bmatrix} f_1(x) \\ f_2(x) \\ \vdots \\ f_k(x) \end{bmatrix}$$

subject to m inequality constraints with $i = \{1, \dots, m\}$

$$g_i(x) \leq 0$$

and p equality constraints with $j = \{1, \dots, p\}$

$$h_j(x) = 0$$

where x is a n-dimensional decision variable vector from some universe Ω containing the solution that optimizes the components of the vector $F(x)$

$$x = \{x_1, \dots, x_n\}$$

In order to fully understand the multi-objective problem, the concepts of dominance, Pareto optimality, Pareto front and Pareto solutions are necessary as they are inherently linked to them. First, a vector $u = (u_1, \dots, u_k)$ is said to strictly dominate another vector $v = (v_1, \dots, v_k)$ formally

$$u \prec v$$

if and only if u is "more optimal" than v, that, in case of minimization, corresponds to the formalization

$$\forall i \in (1, \dots, k),\ \ u_i \leq v_i \wedge \exists i \in (1, \dots, k):\ \ u_i < v_i$$

and, in case of maximization,

$$\forall i \in (1, \dots, k),\ \ u_i \geq v_i \wedge \exists i \in (1, \dots, k):\ \ u_i > v_i$$

Then, intuitively, the solution of a multi-objective problem is not unique but rather a set of optimal and equivalent points that represent the Pareto frontier, i.e. the set of feasible solutions for which all points along the frontier are mathematically equal and valid. The achieved set of solutions is of no preference and it is up to the policy maker to select the best option according to their own preferences and needs. Using a mathematical formalization, a Pareto optimal solution is defined as follows: if the vector $x^* = \{x_1^*, x_2^*, \dots, x_n^*\}$ satisfies the condition

$$\nexists x \in \Omega : F(x) \prec F(x^*)$$

then x^* is called a global Pareto optimal solution with respect to Ω, which is the decision variable space. All global Pareto optimal solutions constitute a global Pareto optimal set, expressed as PS^*:

$$PS^* = \{x^* \in \Omega | \nexists x \in \Omega,\ \ F(x) \prec F(x^*)\}$$

The Pareto optimal set plotted in the objective functions space is called Pareto optimal front, which is defined as the set of non-dominated solutions belonging to the global Pareto optimal set plotted on the objective space, or formally

$$PF^* = \{F(x^*) | x^* \in PS^*\}$$

In other words, the solution x^* is Pareto optimal if there is no other vector x that would represent a "more optimal" solution with respect to x^* by improving the performance of at least one of the objective functions.

Thus, a multi-objective problem consists of k objectives reflected in the k objective functions, $m + p$ constraints on the objective functions and n decision variables. In particular, given a function

$$F : \Omega \subseteq \mathbb{R}^n \rightarrow \mathbb{R}^k$$

with $\Omega \neq 0$ and $k > 2$, for $x \in \Omega$ the set $\mathcal{PF}^* \triangleq F(x_i^*)$ is called the global optimum if and only if

$$\forall x \in \Omega: F(x_i^*) \preccurlyeq F(x)$$

and x_i^* with $i = \{1, \dots, n\}$ is the global optimum solution set $\mathcal{PS}^*$. Therefore, the Pareto optimal solutions are those which, when evaluated, produce vectors whose performance f_i cannot be improved without adversely affecting another f_j, with $i \neq j$. In other words, x_i^* is Pareto optimal only if there exists no other x_i that would improve f_i while maintaining all other $f_{j \neq i}$ constant.

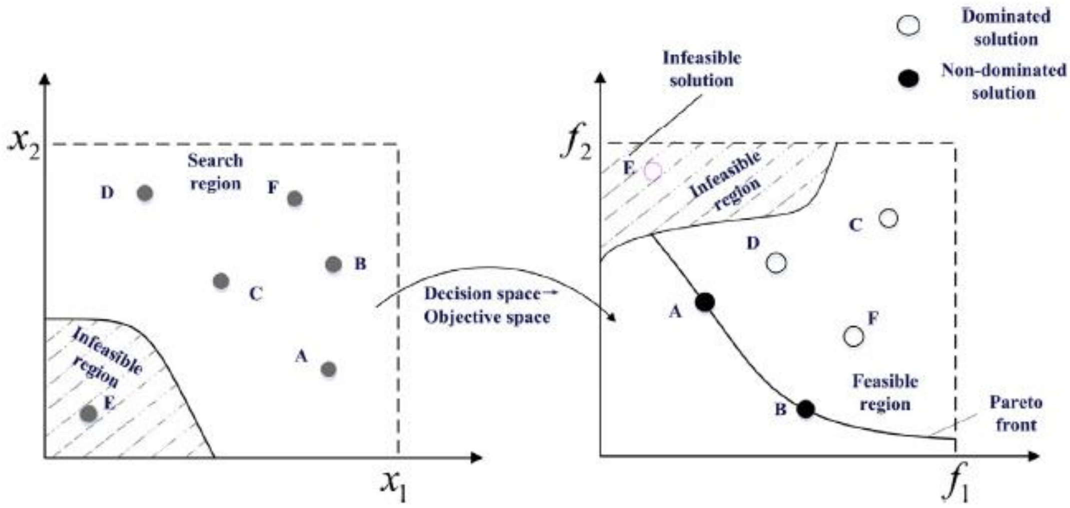


Figure 4.2 - Visual representation of Pareto front [43]

4.3 Multi-objective techniques

According to Y. Cui et al. [43], there are mainly two kinds of methods to solve optimization problems:

- Analytical methods consist in mathematical formalizations and derivations and can reach exact solutions, but are not feasible for many problems;
- Numerical methods use iterative methods to reach approximated solutions but can be applied to all problems.

To the numerical methods belong the techniques which are used in this model (Figure 4.3). Among them, there is a number of multi-objective optimization techniques currently in use that, according to the classification proposed by Cohon and Marks and reported in Chiandussi et al. [46], can be classified depending on the way in which each method works:

- *A Priori Preference* methods include those approaches for which a certain desired target goal or a certain priority of the objectives is defined by the decision maker before the optimization;

- *A Posteriori Preference* methods does not require any prior preference information by the decision maker;
- *Progressive Preference* methods alternate the decision making and the optimization phases, each time modifying the preferences of the objectives according to the intermediate results;
- *Evolutionary Algorithms* comprehend stochastic methods that simulate the Darwin's theory of the survival of the fittest as for natural ecosystems, i.e. on the idea that solutions that are non-dominated are chosen to remain and reproduce in the population of the variable space.

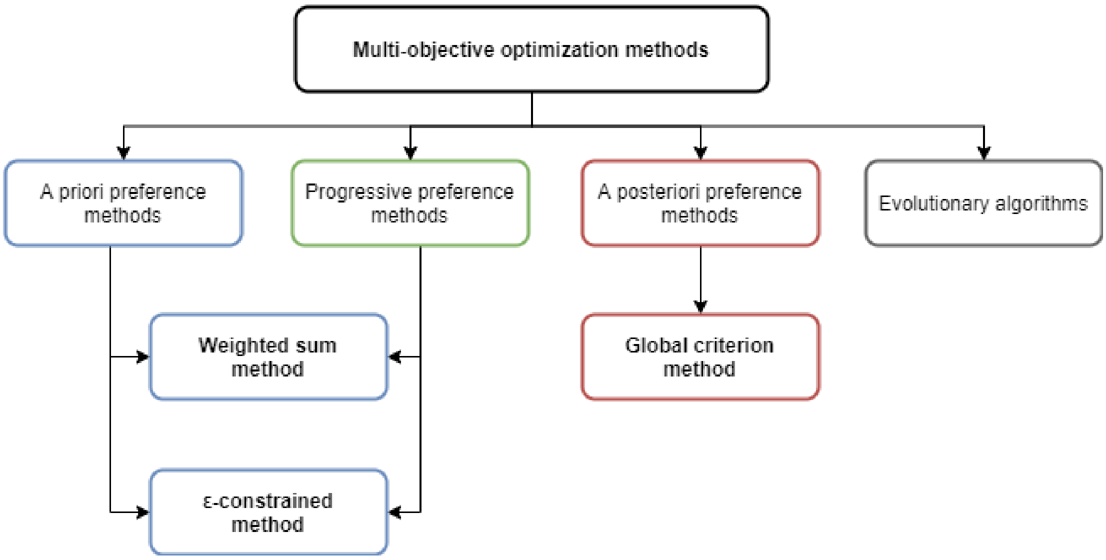


Figure 4.3 - Classification ot the main multi-objective optimization methods [46]

Global criterion method

The global criterion is an example of *a posteriori* methodology. In order to explain how it works, it is useful to define what the ideal vector is. If a vector $x^{0(i)}$ is considered

$$x_i^0 = \begin{bmatrix} x_1^0 \\ x_2^0 \\ \vdots \\ x_n^0 \end{bmatrix}$$

and defined as the vector of variables that optimizes the i^{th} objective function $f_i(x)$ of a generic multi-objective function $F(x) = [f_1(x), f_2(x), \dots, f_k(x)]$ or, in other words, the vector $x^0 \in \Omega$ such that

$$f_i^0 = f_i(x_i^0) = optimum[f_i(x)]$$

then the vector

$$F^0 = F(x_i^0) = \begin{bmatrix} f_1^0 \\ f_2^0 \\ \vdots \\ f_k^0 \end{bmatrix} = \begin{bmatrix} f_1(x_1^0) \\ f_2(x_2^0) \\ \vdots \\ f_k(x_k^0) \end{bmatrix}$$

where $f_i^0 = f_i(x_i^0)$ denotes the optimum for the i^{th} function, is defined as the ideal vector of the multi-objective problem or, in other words, the vector that contains the optimum for each separately considered objective function.

Knowing the concept of ideal vector, the global criterion method aims at minimizing a function defined to be a measure of how close the decision maker can get to the ideal vector F^0, as shown in the following equation:

$$Obj = opt \sum_{i=1}^{k} \left(\frac{f_i^0 - f_i(x)}{f_i^0} \right)^p \tag{4.1}$$

where k is the number of objectives f_i of the multi-objective function $F(x)$ and p is an exponentiation factor. Sometimes the global objective function can be also found in the form

$$Obj = opt \left[\sum_{i=1}^{k} \left(\frac{f_i^0 - f_i(x)}{f_i^0} \right)^p \right]^{\frac{1}{p}} \tag{4.2}$$

or also, according to Y. Cui et al. [43], in absolute terms:

$$Obj = opt \sum_{i=1}^{k} \left(f_i^0 - f_i(x) \right)^p \tag{4.3}$$

or

$$Obj = opt \sum_{i=1}^{k} \left| f_i^0 - f_i(x) \right| \tag{4.4}$$

The main advantage of this method is its simplicity and effectiveness because it does not require a Pareto ranking procedure to be implemented or a decision maker to priorly set his or her preferences. Moreover, it is particularly effective in solving linear programming problems, even though the definition of the ideal vector requires extra computational effort. The desired values for each single objective function can be also set not to be the ideal vector, but some other desired values $\overline{f_i}$ instead:

$$Obj = opt \sum_{i=1}^{k} \left| \overline{f_i} - f_i(x) \right| \tag{4.5}$$

but, in this case, the target value would have to be previously defined by the policy maker and the global criterion would become an *a priori* method.

Weighted sum method

The linear combination of weights or weighted sum method is based on the assumption that the optimum of a multi-objective problem can be calculated by converting the optimization into a problem in which the objective function is a weighted combination of the single objective functions or, in equation:

$$Obj = opt \sum_{i=1}^{k} \alpha_i \cdot f_i(x) \tag{4.6}$$

where $\alpha_i \geq 0$ with $i = (1,2, \dots, k)$ is the set of weighted coefficients of which at least one is nonnull. In this way, the multi-objective problem is converted into a single objective problem, which can be solved by classical optimization algorithms. The values for each α_i can also vary to generate a set of different scenarios.

Some variants can be found as sum of powers of the original components:

$$Obj = opt \sum_{i=1}^{k} [\alpha_i \cdot f_i(x)]^p \tag{4.7}$$

or, knowing the ideal vector,

$$Obj = opt \sum_{i=1}^{k} \alpha_i \cdot \frac{f_i(x)}{f_i^0} \tag{4.8}$$

According to Y. Cui et al. [43], another variant of the linear combination of weights method is the weighted product method

$$Obj = opt \prod_{i=1}^{k} [f_i(x)]^{\alpha_i} \tag{4.9}$$

The advantage of weighted sum method is that it is easy to understand and apply. However, the optimum will strongly depend on the choice of the weighted parameters and, therefore, it has to be taken by the decision maker beforehand according to his or her preferences, making the linear combination of weights an example of *a priori* or at most *progressive preference* methods.

In the article by 2016 "Economic and environmental optimization for distributed energy resource systems coupled with district energy networks" by Longxi Li, Hailin Mu, Nan Li and Miao Li [44], a weighted sum methodology is used in a MILP problem, relatively to a neighbourhood containing 4 residential and office buildings, where the objective functions are 1) the total annual cost and 2) the CO_2 emissions. Other than the power demand, the heating and cooling needs are considered as well, while the decision variables x become the gas power generators, auxiliary boilers, heat recovery systems, absorption and compression chillers, heating exchangers, heat and cold storages, PV and district energy networks. The objective function is defined as the weighted sum of the two objectives, therefore:

$$Objective = max\left(w_{cost} \cdot \frac{C_{ref} - C_{DER}(x)}{C_{ref}} + w_{emissions} \cdot \frac{E_{ref} - E_{DER}(x)}{E_{ref}}\right) \quad (4.10)$$

where w_{cost} is the weight of the costs objective, $w_{emissions}$ the one of the emissions objective with $w_{cost} + w_{emissions} = 1$, C_{ref} and E_{ref} the total costs and emissions of the reference energy system and C_{DER} and E_{DER} the costs and emissions of the Distributed Energy Resources system to be optimized.

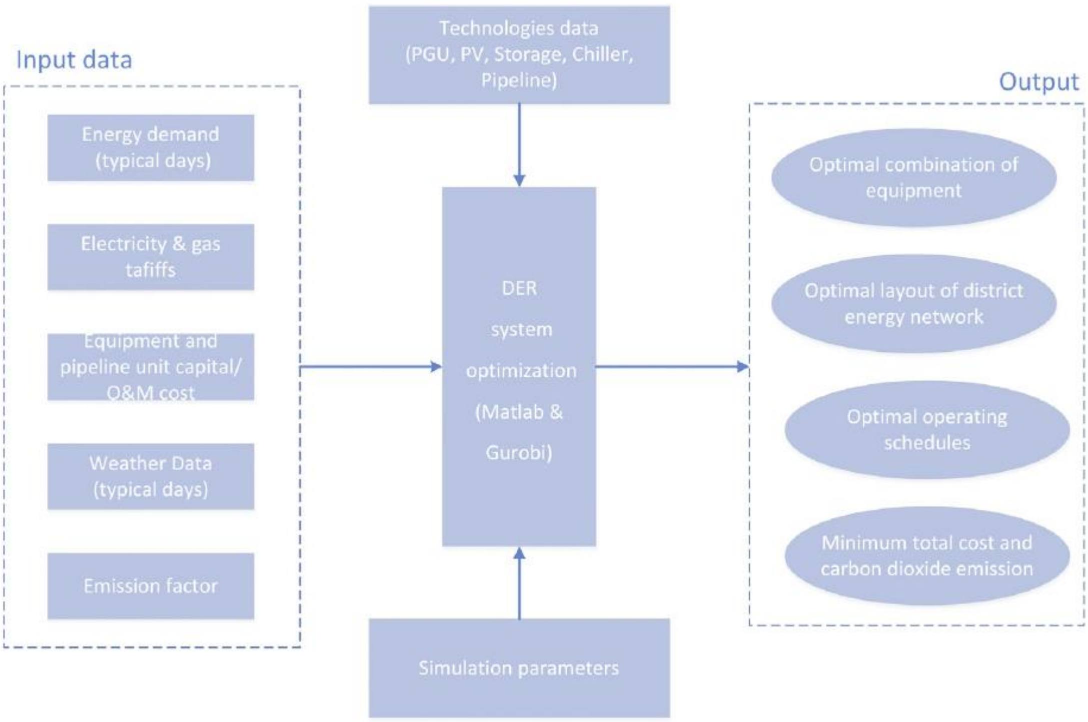


Figure 4.4 – Scheme of the optimization process in [44]

The 2009 article "Multi-objective assessment of rural electrification in remote areas with poverty considerations", by Diego Silva and Toshihiko Nakata [47] offers another example of application of a multi-objective problem, related to a micro-grid in Colombia, based on an order of preferences or priority methodology, which is a similar method to the weighted sum criterion. In particular, four objectives are defined, which are 1) the electricity generation cost, 2) the employment generation, 3) the land use and 4) the avoided emissions. The benefits, in this case, are defined as the deviation with respect to a given target for each objective, according to the following equations:

$$b_j(x) = \frac{g_j(x) - A_j}{g_j} \cdot 100, \ \ j = \{Electricity\ cost,\ \ land\ use\}$$

$$b_j(x) = \frac{A_j - g_j(x)}{g_j} \cdot 100, \ \ j = \{Employment\ generation,\ \ Avoided\ emissions\} \quad (4.11)$$

where g_j denotes the actual value of objective j, A_j the target value and b_j the percentage deviation of the objective j with respect to its target value. The problem, consequently, is defined as the minimization of the sum of the percentage deviations of the objectives multiplied per their priority factors P_j, by finding the optimal electricity supplied by each technology which is the vector of decision variables x:

$$Objective = min \sum_j P_j \cdot b_j\,(x) \tag{4.12}$$

subject to constraints related to the maximum electricity generation cost, minimum employment generation, maximum land use and minimum avoided emissions in the form

$$\begin{gathered} g_j(x) \le \varepsilon_j,\ \ j = \{Electricity\ cost,\ \ land\ use\} \\ g_j(x) \ge \varepsilon_j,\ \ j = \{Employment\ generation,\ \ Avoided\ emissions\} \end{gathered} \tag{4.13}$$

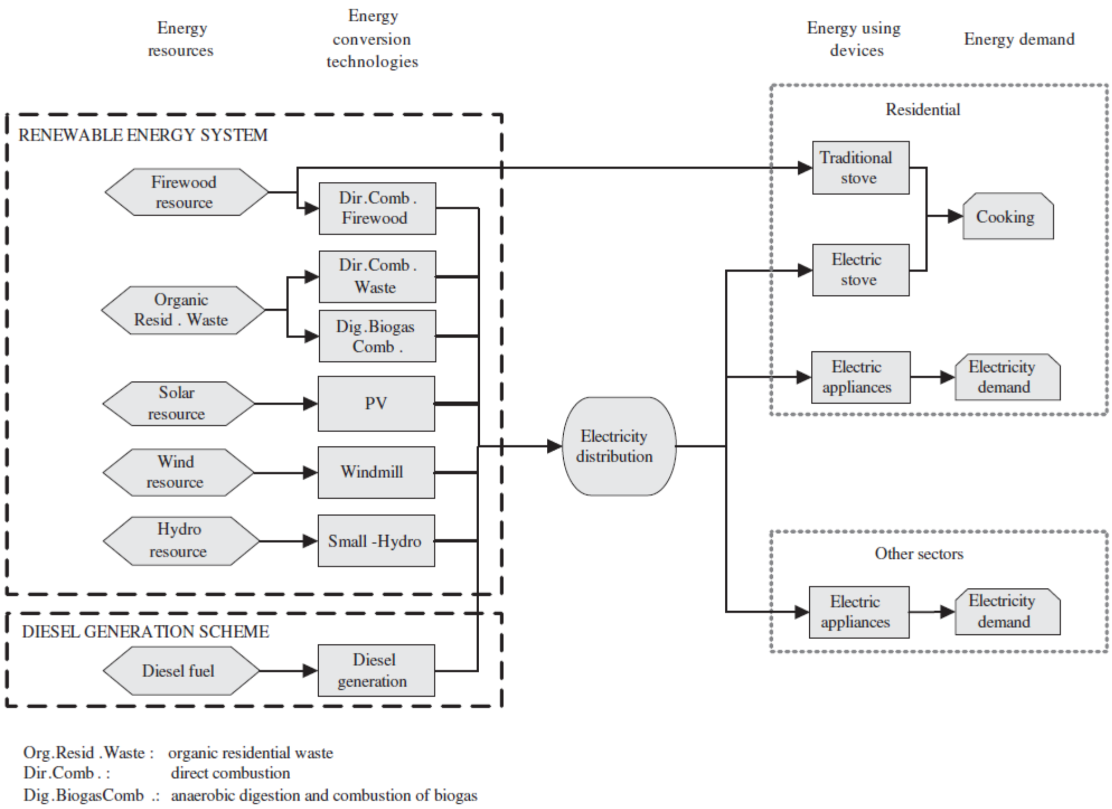


Figure 4.5 – Scheme of the optimization process in [47]

The ε-constraint method

The ε-constraint method requires no aggregation of criteria, instead only one of the original single objectives is optimized while the others are transformed to constraints fixing upper or lower bounds ε_i. In other words, the problem $opt[f_1(x), \dots, f_k(x)]$ is converted into

$$opt\big[f_j(x)\big],\ \ f_i(x) < \varepsilon_i,\ \ i = 1, \dots, k,\ \ i \ne j \tag{4.14}$$

or

$$opt[f_j(x)], \ \ f_i(x) > \varepsilon_i, \ \ i = 1, \dots, k, \ \ i \neq j \tag{4.15}$$

This method guarantees that the objective function $f_j(x)$ reaches the ideal value, but, if the constraints of the other functions are too small, the algorithm may not find feasible solutions or, on the contrary, if the constraints are too large, the other objectives may have excessive losses.

An example of ε-constrained method is offered by the 2015 article "Optimal design of CHP-based microgrids: Multi-objective optimisation and life cycle assessment" by Zhang, Evangelisti, Lettieri, Lazaros and Papageorgiou [45]. In this article, a MILP problem is used to optimize a distributed generation system, including micro CHP units, back-up boilers and PV units, relatively to a small neighbourhood, by considering both economic and environmental aspects. The decision variables x are the selection of technologies and their capacities and are obtained by minimizing three objectives: 1) the total equivalent annualized cost ($EEC(x)$), 2) the global warming potential ($GWP(x)$, kg of CO_2), and 3) the acidification potential ($AP(x)$, kg of SO_2). At this point, an ε-constrained optimization method is performed. First, the cost objective $EEC(x)$ is minimized by assigning an upper bound to $GWP(x)$:

$$Objective = min\big(EEC(x)\big), \ \ GWP(x) \leq \varepsilon_{GWP} \tag{4.16}$$

where ε_{GWP} is a function of the lowest and highest values of GWP. Then, $EEC(x)$ is once again minimized by assigning an upper bound to the weighted sum of $GWP(x)$ and $AP(x)$:

$$Objective = min\big(EEC(x)\big), \ \ w_{GWP} \cdot GWP(x) + w_{AP} \cdot AP(x) \leq \varepsilon_{GWP-AP} \tag{4.17}$$

where ε_{GWP-AP} is defined in a similar way to ε_{GWP}.

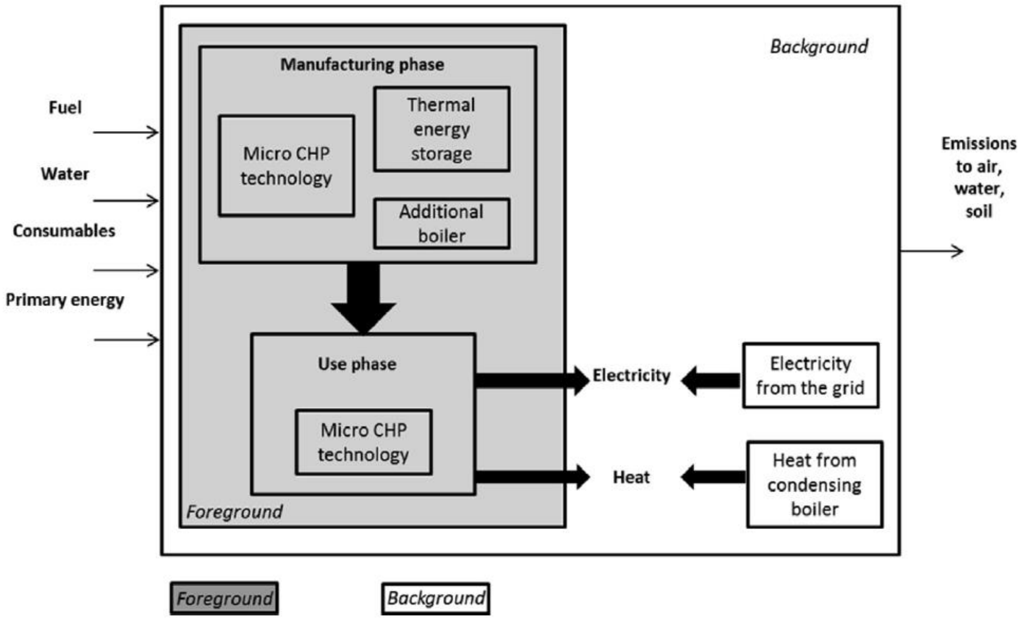


Figure 4.6 – Scheme of the optimization process in [45]

Chapter 5
Proposed Model

As already introduced, in this thesis work a procedure able to perform a multi-objective optimization of the energy system of an area where an energy community is introduced has been developed. As part of the decisional power over its evolution is shifted from the traditional market actors to the hands of the energy community, the model analyses how the energy system could develop according to the goals and preferences of the citizens with respect to the objectives that the policy maker is willing to pursue: in particular, the objectives chosen are the minimization of the fluxes through the transformation primary substation, the annual CO_2 emissions by the energy consumption and, lastly, the costs for the energy community itself. All these objectives are then merged in a multi-objective optimization problem solved by means of a global criterion and a weighted sum methodology. The procedure refers to a single geographic area defined as the set of all citizens living in the municipalities afferent to a single HV/LV primary substation, assuming that:

1) all citizens living in an area join the energy community, and
2) only one energy community is introduced in each area.

Even though in certain cases they may be unlikely to correspond to verisimilar situations, these hypotheses are necessary to avoid the need to model the energy and monetary exchanges among different energy communities in a single area, but rather only between the energy community and the grid, and to simplify the model itself. This assumption reflects both the most recent Italian normative, i.e. Law 28 February 2020, n.8 [16] that limits the energy communities to be afferent to a single substation, and the radial shape of the Italian electricity grid, where a single primary substation covers different municipalities and, viceversa, each municipality is reached by a single substation. Performing an energy planning of an area, consequently, corresponds, first, to optimize the utilization of the existing electricity infrastructure without the need to install new transmission lines among different areas and, second, to allow considerations on the electricity self-consumption and independency from the grid. In practice, even if different energy communities are introduced in a single area, the model neglects their multiplicity and considers them as an aggregate.

This chapter formally defines all the elements of the model, starting from the sets and continuing on the parameters, variables, constraints and objective functions.

5.1 Sets

The sets used in the model are first of all defined. Each profile is associated to a set representing the timesteps of the model:

$$t$$

In the case study, as will be furtherly detailed in Chapter 6, the timesteps have a resolution of 15 minutes and a length of a year. This is the reason for which the variables and objectives in Chapter 5.5 are given a factor $1/4$, so that the unit dimension kWh can still be used rather than $kW \cdot 15'$.

5.2 Parameters

Generation

The procedure requires to have a number of input parameters regarding the generation, the load profiles and the heating demand. For what concerns the first, the normalized generation profiles of every considered source in per unit dimension are defined:

$$p_k(t)[pu]$$

To each source k, a set of parameters regarding its costs are also defined, namely the specific investment cost, the specific annual O&M and the specific variable cost of operation:

$$c_k^{Inv}\left[\frac{€}{kW}\right]$$

$$c_k^{O\&M}\left[\frac{€}{kW \cdot y}\right]$$

$$c_k^{Var}\left[\frac{€}{kWh}\right]$$

Also, a CO_2 emission factor is assigned to each source:

$$e_k^{CO_2}\left[\frac{t_{CO_2}}{kWh}\right]$$

Load

Similarly to the generation profiles, also the electrical power transits through the primary substation – i.e. for an area – are known:

$$L_{EE}(t)[kW]$$

where $L_{EE}(t)$ is positive when the power is entering the area, negative otherwise. It is important to clarify that the load does not represent the electrical demand but rather the difference between the actual demand and the current local generation at all times. In other words, it represents the overall energy need or energy surplus of an area.

Moreover, two parameters related to the costs are defined, the first being the electricity cost for the consumers and the second the zonal price, with both varying during the year:

$$c_{El}(t)\left[\frac{€}{kWh}\right]$$

$$p_{Zone}(t)\left[\frac{€}{kWh}\right]$$

As for generation, an emission factor associated to the consumption of electricity coming from the grid is also defined, such that the emissions embedded in the grid electricity are also considered:

$$e_{Grid}^{CO_2}\left[\frac{t_{CO_2}}{kWh}\right]$$

Heating electrification

The model necessitates the generation of the heating demand profile. In particular, the first step requires the annual useful nonelectric energy for heating to be obtained by means of conversion efficiencies. After this, the temperature profile, the households' characteristics, the heating normative and the domestic heating plant use habits are utilized to redistribute it among all the timesteps. Lastly, the useful energy for heating is converted to an electric load profile for heating – to be summed up to the already present electric load – by considering two heat pumps technologies. The procedure is performed for a single household, after which the outcomes of all households can be summed up to obtain the overall heating profile (Figure 5.1).

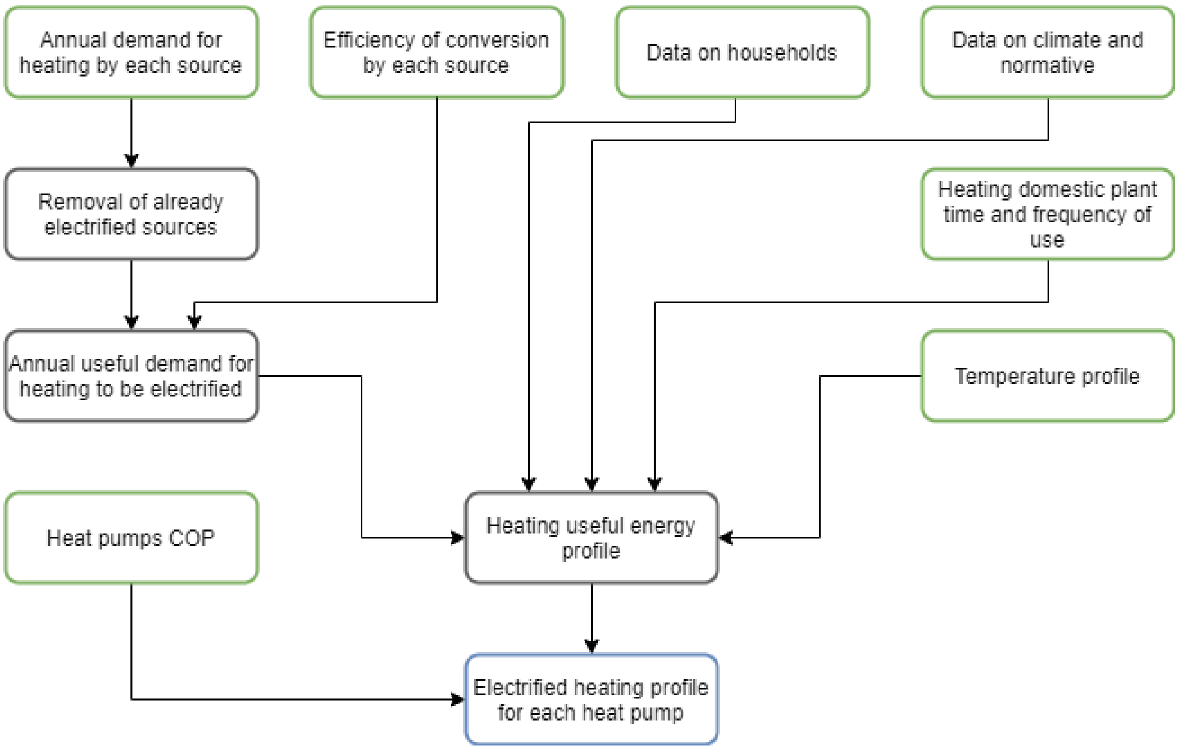


Figure 5.1 - Scheme of the heating profile building

The first input, therefore, is the total annual primary energy consumption for heating PE_i of each source of energy i and its conversion into useful energy E_i by means of the average efficiency of conversion η_i:

$$E_i[kWh_{th}] = PE_i \cdot \eta_i \tag{5.1}$$

However, since the focus of the model is the electrification of heating, the already electrified sources are removed from the calculations since they are already comprised in the electric load, obtaining in this way the annual useful energy demand for heating that can be electrified for the purposes of this model:

$$E_{Non-electric}[kWh_{th}] = \sum_{i=Non-electric} E_i \tag{5.2}$$

Another required input is the outdoor temperature profile:

$$T(t)[°C]$$

At this point the single households are considered, for which the total number N, the average surface S, the average annual energy consumption specific to the surface e and the assumed daily operating hours $hours$ of the domestic heating plant are required:

$$N[-]$$

$$S[m^2]$$

$$e\left[\frac{kWh_{th}}{year \cdot m^2}\right]$$

$$hours[h]$$

In this way, the annual heating demand of a single household can be calculated:

$$E_{Heating}\left[\frac{kWh_{th}}{year}\right] = e\left[\frac{kWh_{th}}{year \cdot m^2}\right] \cdot S[m^2] \cdot \frac{hours[h]}{24[h]} \tag{5.3}$$

Now it is possible to singularly simulate the real heating behaviour in order to obtain the heating profile of the household. First of all, a reference temperature is randomly assumed, i.e. the indoor temperature below which the heating system is switched on and provides heat according to the normative D.P.R. n. 74/’13:

$$T_{ref} = 20 \pm 2\ [°C] \tag{5.4}$$

Now, a temperature difference profile $\Delta T(t)$ can be found:

$$\Delta T(t) = T_{ref} - T(t) \tag{5.5}$$

At this point, an important passage is the modification of the $\Delta T(t)$ profile by accounting for the frequency of use of the domestic heating plant and the occupation frequency of the household, so that a $\Delta T(t)$ is existing only when the heating plant is used and nullified in those timesteps where the domestic heating plant is simulated to be switched off:

$$\Delta T(t) = \begin{cases} \Delta T(t), & t \in t_{Switched-on} \\ 0, & t \notin t_{Switched-on} \end{cases} \tag{5.6}$$

Finally, the profile for heating $P'_{Heating}(t)$ can be obtained by multiplying the annual energy consumption of the household $E_{Heating}$ per a factor represented by the share of the $\Delta T(t)$ over the sum of all the temperature differences at all timesteps $\sum_t \Delta T(t)$:

$$P'_{Heating}(t)[kW_{th}] = E_{Heating} \cdot \frac{\Delta T(t)}{\sum_t \Delta T(t)} \tag{5.7}$$

This procedure is performed for each each single household and all resulting profiles are summed up to obtain the overall heating profile of a set of households. However, the subsequent $P'_{Heating}(t)$ has to be modified such that only the non-electrified energy demand for heating to be electrified is comprised. In order to do this, it is enough to multiply all the values in $P'_{Heating}(t)$ per a multiplication factor FM defined as

$$FM[-] = \frac{E_{Non-electric}}{\sum_t P'_{Heating}(t)} \tag{5.8}$$

Obtaining the final non-electric power profile for heating $P_{Heating}(t)$ to be electrified:

$$P_{Heating}(t)[kW_{th}] = P'_{Heating}(t) \cdot FM \tag{5.9}$$

Now that the heating profile with a 15-minutes resolution $P_{Heating}(t)$ is obtained, the next step is the electrification of heating by considering different heat pump technologies by assuming a COP varying with the temperature:

$$COP_j(\Delta T)[-]$$

However, knowing the temperature difference profile $\Delta T(t)$, it is possible to obtain the COP_j for each heat pump technology j as a function of time t:

$$COP_j(\Delta T) = COP_j\big(\Delta T(t)\big) = COP_j(t)$$

Consequently, the electrical power needed to cover the heating power demand $P_{Heating}(t)$ by each technology j is obtained:

$$P_j^{Heating}(t)[kW] = \frac{P_{Heating}(t)}{COP_j(t)} \tag{5.10}$$

Other parameters related to the heating side are also introduced. First, the nominal power of the heat pumps is assumed, as well as the number of households where the HPs can be installed:

$$P_{nom}^{HP}[kW]$$

$$Households[-]$$

Then, the specific investment cost and the O&M of the heat pumps are defined:

$$c_j^{Inv}\left[\frac{€}{kW}\right]$$

$$c_j^{O\&M}\left[\frac{€}{kW \cdot y}\right]$$

Lastly, the average specific costs and emissions related to the heating demand of the area before the installation of the heat pumps are specified:

$$c_{Heating}\left[\frac{€}{kWh_{th}}\right]$$

$$e_{Heating}^{CO_2}\left[\frac{t_{CO_2}}{kWh_{th}}\right]$$

Storage

The storage model is taken by MicroGridsPy – Multi-year capacity-expansion (MYCE) of the year 2018/2019, written by Giulia Guidicini and Lorenzo Rinaldi of Politecnico di Milano and based on the original model by Sergio Balderrama and Sylvain Quoilin of 2017, originally written for the optimization of the generation mix and the storage capacity for micro grids in developing countries [62]. A number of parameters is used to describe the technical specifications of the storage system. First, the charge and discharge efficiencies are defined:

$$\eta_{Charge} = \eta_{Discharge} = 0.95[-]$$

Then, the Depth of Discharge, i.e. the fraction of the stored energy that cannot be extracted but remains in the storage system, is defined to be equal to 10%:

$$DOD = 0.1[-]$$

The maximum battery charge and discharge times are then defined:

$$\Delta h_{Charge} = \Delta h_{Disharge} = 3[h]$$

The initial State of Energy of the battery, i.e. the initial energy stored in the battery as a fraction of the total capacity, is also defined to be equal to 100%:

$$SOE_0 = 1[-]$$

A factor Δh_{Step}, that is the duration of the timestep as a fraction of an hour, is specified to be equal to 15 minutes as the timestep of the model:

$$\Delta h_{Step} = 15[min] = 0.25[h]$$

Lastly, the investment and O&M costs specific to the battery capacity, as well as the specific CO_2 emissions by the production of the battery itself, are also defined:

$$c_{Battery}^{Inv}\left[\frac{€}{kWh}\right]$$

$$c_{Battery}^{O\&M}\left[\frac{€}{kWh\cdot y}\right]$$

$$e_{Battery}^{CO_2}\left[\frac{t_{CO_2}}{kWh}\right]$$

Table 5.1 summarizes all the parameters used in the model.

Table 5.1 - List of all the parameters used in the model

Parameter	Description	Unit
$p_k(t)$	Normalized generation profile of source k	pu
c_k^{Inv}	Specific investment cost of source k	$€/kW$
$c_k^{O\&M}$	Specific O&M cost of source k	$€/kW \cdot y$
c_k^{Var}	Specific variable cost of source k	$€/kWh$
$e_k^{CO_2}$	Emission factor of source k	t_{CO_2}/kWh
$L_{EE}(t)$	Electric load at transformation primary substation	kW
$c_{El}(t)$	Cost of electricity for consumers	$€/kWh$
$p_{Zone}(t)$	Zonal price	$€/kWh$
$e_{Grid}^{CO_2}$	Emission factor embedded in grid electricity	t_{CO_2}/kWh
$P_{Heating}(t)$	Profile of useful non-electric energy for heating	kW_{th}
$P_j^{Heating}(t)$	Profile of useful non-electric energy for heating electrified with technology j	kW
P_{nom}^{HP}	Nominal power of heat pumps	kW
$Households$	Total number of households	$-$
c_j^{Inv}	Specific investment cost of heat pump j	$€/kW$
$c_j^{O\&M}$	Specific O&M cost of heat pump j	$€/kW \cdot y$
$c_{Heating}$	Average heating specific cost prior to the electrification	$€/kWh_{th}$
$e_{Heating}^{CO_2}$	Average heating emission factor prior to the electrification	t_{CO_2}/kWh_{th}
η_{Charge}	Charge efficiency of battery	$-$
$\eta_{Discharge}$	Discharge efficiency of battery	$-$
DOD	Depth Of Discharge of battery	$-$
Δh_{Charge}	Minimum charge time of battery	h
$\Delta h_{Disharge}$	Minimum discharge time of battery	h
SOE_0	Initial State Of Energy of battery	$-$
Δh_{Step}	Time duration of the timestep used in the model	h
$c_{Battery}^{Inv}$	Specific investment cost of the battery	$€/kWh$
$c_{Battery}^{O\&M}$	Specific O&M cost of the battery	$€/kWh \cdot y$
$e_{Battery}^{CO_2}$	Specific emission factor of the battery	t_{CO_2}/kWh

5.3 Variables

Generation

After the parameters, the model considers a set of variables that will be optimized according to the objective functions. For what concerns the generation, the variables related to the additional capacity to install of each source k are defined:

$$x_k[kW]$$

Considering the contribution of each source, the overall additional generation is:

$$Generation(t)[kW] = \sum_k x_k \cdot p_k(t)$$

Load

Two variables related to the residual transit are defined, namely the positive residual profile – i.e. the one entering the area – and the negative residual profile – the one exiting the area:

$$Z^+(t),\ \ Z^-(t)[kW]$$

with $Z_m^+(t) > 0$ and $Z_m^-(t) < 0$.

Moreover, in all scenarios the following energy balance equation is always valid:

$$Z^+(t) + Z^-(t) = L_{EE}(t) + L_{Heating}(t) - \sum_k x_k \cdot p_k(t) + F_{Battery}(t) \tag{5.11}$$

Heating

Then, the overall heating electrification – i.e. the fraction of the heating demand that is switched from being covered from traditional sources to HPs – is defined:

$$f_{Heating}[-]$$

Also, the mix of heat pumps is represented by a set of variables that correspond to the share of the heating demand covered by each heat pump technology:

$$x_j[-]$$

Again, by considering the contribution of all HPs technologies, the additional electrical load by electrifying the heating demand can be defined as a weighted sum of the electric loads by each technology j according to the factors x_j:

$$L_{Heating}(t)[kW] = \sum_j x_j \cdot P_j^{Heating}(t) \tag{5.12}$$

Storage

For what concerns the storage, the nominal battery capacity to be installed is defined first:

$$C_{Battery}[kWh]$$

Then, the State of Energy of the battery at every timestep t, with the same dimension as $C_{Battery}$, differently from SOE_0 which is defined as a fraction instead:

$$SOE(t)[kWh]$$

The average powers exiting and entering the battery during all the timesteps t are then specified:

$$P_{Battery}^{out}(t),\ \ P_{Battery}^{in}(t)[kW]$$

Notice that the storage impacts the electric load in both directions, since the charging power adds up to the already present electrical load and the discharging power has the same sign as the generation. A net flux can be therefore introduced as the difference between entering and exiting powers:

$$F_{Battery}(t)[kW] = P_{Battery}^{in} - P_{Battery}^{out} \tag{5.13}$$

For the relations among the storage variables, refer to Chapter 5.4.

Table 5.2 summarizes all the variables used in the model.

Table 5.2 - List of all the variables used in the model

Variable	Description	Unit
x_k	Additional generation capacity of source k	kW
$Z^+(t)$	Residual positive (entering) profile	kW
$Z^-(t)$	Residual negative (exiting) profile	kW
$f_{Heating}$	Overall electrification of heating	$-$
x_j	Electrification by heat pump technology j	$-$
$C_{Battery}$	Additional battery capacity	kWh
$SOE(t)$	State Of Energy of battery	kWh
$P_{Battery}^{out}(t)$	Power exiting the battery	kW
$P_{Battery}^{in}(t)$	Power entering the battery	kW
$F_{Battery}(t)$	Net flux of the battery	kW

5.4 Constraints

Generation

A number of constraints is defined in the optimization problem. First, the additional generation capacities by each source are assigned a lower and an upper bound, eventually varying depending on the scenario:

$$0 \leq x_k \leq x_k^{max} \tag{5.14}$$

Load

The residual profiles $Z^{+}(t)$ and $Z^{-}(t)$ are also given an upper and lower bound, respectively, to account for the primary substation power limitations:

$$
\begin{aligned}
Z^{+}(t) &\leq Z^{+,max} \\
Z^{-}(t) &\geq -Z^{-,max}
\end{aligned}
\tag{5.15}
$$

Heating

The electrification fraction is of course lower than 1 and each HP technology penetration is given an upper bound:

$$
\begin{aligned}
f_{Heating} &\leq 1 \\
x_j &= x_j^{max}
\end{aligned}
\tag{5.16}
$$

Moreover, the sum of the penetrations by each HP is defined to be equal to the overall electrification:

$$
\sum_j x_j = f_{Heating} \tag{5.17}
$$

Storage

The maximum storage capacity to be installed in each area is first of all assigned an upper bound:

$$
C_{Battery} \leq C_{Battery}^{max} \tag{5.18}
$$

Then, a further set of constraints and relations among the variables and parameters is also considered. First, the energy balance for the battery at every timestep t, with the first timestep $t = 0$ being dependent on SOE_0:

$$
\begin{aligned}
SOE(t=0) &= C_{Battery} \cdot SOE_0 - \frac{P_{Battery}^{out}(t)}{\eta_{Discharge}} + P_{Battery}^{in}(t) \cdot \eta_{Charge} \\
SOE(t) &= SOE(t-1) - \frac{P_{Battery}^{out}(t)}{\eta_{Discharge}} + P_{Battery}^{in}(t) \cdot \eta_{Charge}
\end{aligned}
\tag{5.19}
$$

Then, the State of Energy of the battery at every timestep t is constrained to be higher than the minimum charge of the battery, that is represented by the fraction equal to the DOD, and lower than the maximum charge of the battery, that is the total capacity of the battery itself:

$$
C_{Battery} \cdot DOD \leq SOE(t) \leq C_{Battery} \tag{5.20}
$$

Lastly, the maximum powers entering and exiting are also defined as functions of the battery capacity and the charge and discharge times, according to the following equations:

$$
P_{Battery}^{out,max} = \frac{C_{Battery}}{\Delta h_{Discharge}} \, [kW] \tag{5.21}
$$

$$P_{Battery}^{in,max} = \frac{C_{Battery}}{\Delta h_{Charge}} \, [kW]$$

Moreover, the powers entering and exiting the battery at every timestep t must be lower than the maximum allowed powers multiplied per the duration of the timestep:

$$\begin{gathered} P_{Battery,m}^{out}(t) \leq P_{Battery}^{out,max} \cdot \Delta h_{Step} \\ P_{Battery,m}^{in}(t) \leq P_{Battery}^{in,max} \cdot \Delta h_{Step} \end{gathered} \tag{5.22}$$

Considering only the storage part of the model, there is a number of variables equal to 4 and a number of equality constraints equal to 3. This means that in the storage model there is one only free variable on which all the others depend that, in this, case, is the battery capacity $C_{Battery}$.

5.5 Objectives

Fluxes

Different objective functions are considered in the model, first singularly and then simultaneously. The first objective function is related to the minimization of the electricity fluxes from and to the HV electricity grid. More in detail, a quantity $Fluxes_{Tot}$ representing the sum of the absolute values of the differences between total electric load and electric generation over all the timesteps t is defined:

$$Fluxes_{Tot} \left[\frac{kWh}{year}\right] = \sum_{t}^{8760\cdot 4} \left(Z^{+}(t) - Z^{-}(t)\right) \tag{5.23}$$

where the negative sign before $Z^{-}(t)$ is so that the absolute value is considered.

If the fluxes objective function is singularly considered, the optimization problem corresponds to the minimization of the quantity $Fluxes_{Tot}$:

$$\begin{aligned} Objective_{Fluxes} = min(Fluxes_{Tot}) = min\left(\sum_{t}^{8760\cdot 4} \left(Z^{+}(t) - Z^{-}(t)\right)\right) \\ = Fluxes_{0} \end{aligned} \tag{5.24}$$

where $Fluxes_0$ is the minimum value of $Fluxes_{Tot}$ that is obtained when singularly considering the fluxes objective.

Costs

The second objective is the minimization of the costs for the consumers, assuming that all the citizens in the area join a single energy community. In particular, the costs are calculated as a Net Present Cost for the electricity generation and consumption and the heating demand calculated in a 20 years window. However, the NPC, which is usually defined in relative terms in an investment analysis, is here defined in absolute terms to represent the costs that the citizens would have to sustain during the lifetime of the project, rather than the economic convenience of the investment. Therefore, a quantity NPC is defined:

$$NPC[€] = Cost_{Investment} + \sum_{n=1}^{20} \frac{Cost_{O\&M} + Cost_{Variable}}{(1+i)^n} \tag{5.25}$$

Again, if the costs objective is singularly considered, the objective function corresponds to the minimization of the Net Present Cost, as shown in the equation below:

$$\begin{aligned} Objective_{Costs} &= min(NPC) \\ &= min\left(Cost_{Investment} + \sum_{n=1}^{20} \frac{Cost_{O\&M} + Cost_{Variable}}{(1+i)^n}\right) \\ &= NPC_0 \end{aligned} \tag{5.26}$$

where $Cost_{Iinvestment}$ is the total investment cost of the additional generation plants, the storage capacity and the heat pumps, $Cost_{O\&M}$ is the total annual cost for the fixed O&M of all the installed systems, $Cost_{Variable}$ the total annual cost for the plants operation, n the assumed life of the investment equal to 20, i the discount rate assumed to be equal to 0.03 to actualize the costs and, again, NPC_0 the lowest value of NPC that is obtained if the costs objective is singularly considered.

More in detail, the total investment cost $Cost_{Investment}$ is calculated as the sum of the specific installation costs c_k^{Inv} multiplied per the generation capacity to be installed x_k for each source k, plus the investment cost for the heat pumps and for the storage system:

$$\begin{aligned} Cost_{Investment} &= \sum_k c_k^{Inv} \cdot x_k + Households \cdot P_{nom}^{HP} \cdot \sum_j \left(c_j^{Inv} \cdot x_j\right) \\ &+ c_{Battery}^{Inv} \cdot C_{Battery} \end{aligned} \tag{5.27}$$

The total annual fixed O&M costs are given by:

$$\begin{aligned} Cost_{O\&M} = \sum_k c_k^{O\&M} \cdot x_k + Households \cdot P_{nom}^{HP} \cdot \sum_j \left(c_j^{O\&M} \cdot x_j\right) + c_{Battery}^{O\&M} \\ \cdot C_{Battery} \end{aligned} \tag{5.28}$$

Lastly, the total annual variable operation costs are defined as:

$$\begin{aligned} Cost_{Variable} = \sum_t \Bigg\{ & \sum_k c_k^{Var} \cdot x_k \cdot p_k(t) + c_{El}(t) \cdot Z^+(t) + p_{Zone}(t) \cdot Z^-(t) \\ & + \left(1 - f_{Heating}\right) \cdot c_{Heating} \cdot P_{Heating}(t) \Bigg\} \end{aligned} \tag{5.29}$$

where:

- the electricity cost $c_{El}(t)$ is associated to the positive transit $Z^+(t)$,
- the zonal price $p_{Zone}(t)$ is associated to a negative quantity $Z^-(t)$ and is therefore an economic gain, and

- the heating cost represents the fraction of heating that is not electrified $(1 - f_{Heating})$ associated to the cost $c_{Heating}$.

Emissions

The last objective function is the minimization of the emissions by the electricity generation and consumption and the heating demand. A quantity representing the total annual CO_2 emissions is defined:

$$Emissions_{Tot}\left[\frac{t_{CO_2}}{year}\right] = E_{Generation}^{CO_2} + E_{Grid}^{CO_2} + E_{Heating}^{CO_2} + E_{Battery}^{CO_2} \tag{5.30}$$

Again, if the emissions objective is singularly considered, the objective function corresponds to the minimization of the total annual CO_2 emissions:

$$\begin{aligned} Objective_{Emissions} &= min\left(E_{Generation}^{CO_2} + E_{Grid}^{CO_2} + E_{Heating}^{CO_2} + E_{Battery}^{CO_2}\right) \\ &= Emissions_0 \end{aligned} \tag{5.31}$$

where $E_{Generation}^{CO_2}$ are the annual emissions by the additional generation, $E_{Grid}^{CO_2}$ the emissions associated to the consumption of the electricity coming from the grid, $E_{Heating}^{CO_2}$ the emissions by heating and $E_{Battery}^{CO_2}$ the emissions by the production of the battery system.

In particular, the CO_2 emissions from the electricity generation are calculated as the sum of the emissions specific to a kWh produced for all the technologies k and the timesteps t:

$$E_{Generation}^{CO_2} = \sum_{t}^{8760\cdot4} \sum_{k} e_k^{CO_2} \cdot x_k \cdot p_k(t) \tag{5.32}$$

The CO_2 emissions by the electricity consumption from the grid are calculated by considering the average CO_2 content of a kWh of electricity consumed by the grid $e_{Grid}^{CO_2}$ multiplied per the residual positive profile $Z^+(t)$:

$$E_{Grid}^{CO_2} = \sum_{t}^{8760\cdot4} e_{Grid}^{CO_2} \cdot Z^+(t) \tag{5.33}$$

The CO_2 emissions by the nonelectrified heating demand are calculated by considering an average heating emission factor $e_{Heating}^{CO_2}$, multiplied per the useful heating demand $P_{Heating}(t)$:

$$E_{Heating}^{CO_2} = \left(1 - f_{Heating}\right) \cdot \sum_{t}^{8760\cdot4} e_{Heating}^{CO_2} \cdot P_{Heating}(t) \tag{5.34}$$

Lastly, the CO_2 emissions for the battery capacity to be installed, which is the emissions necessary for its production and installation, are calculated as the storage capacity $C_{Battery}$ multiplied per the amount of ton of CO_2 equivalent emitted to produce a battery with capacity equal to 1 kWh $e_{Battery}^{CO_2}$:

$$E_{Battery}^{CO_2} = e_{Battery}^{CO_2} \cdot C_{Battery} \tag{5.35}$$

Multi-objective optimization

When applying the multi-objective methods exposed above to the case of this thesis, the following equations should be considered. Accounting for the global criterion method, the optimization problem should be defined as follows:

$$Objective_{Global} = min\left[\left(\frac{Fluxes_{Tot} - Fluxes_0}{Fluxes_0}\right) + \left(\frac{Emissions_{Tot} - Emissions_0}{Emissions_0}\right) + \left(\frac{NPC_{Tot} - NPC_0}{NPC_0}\right)\right] \quad (5.36)$$

where all the single objective functions are simultaneously considered and are minimized such that the sum of the normalized differences between the punctual and the lowest values possible is minimized.

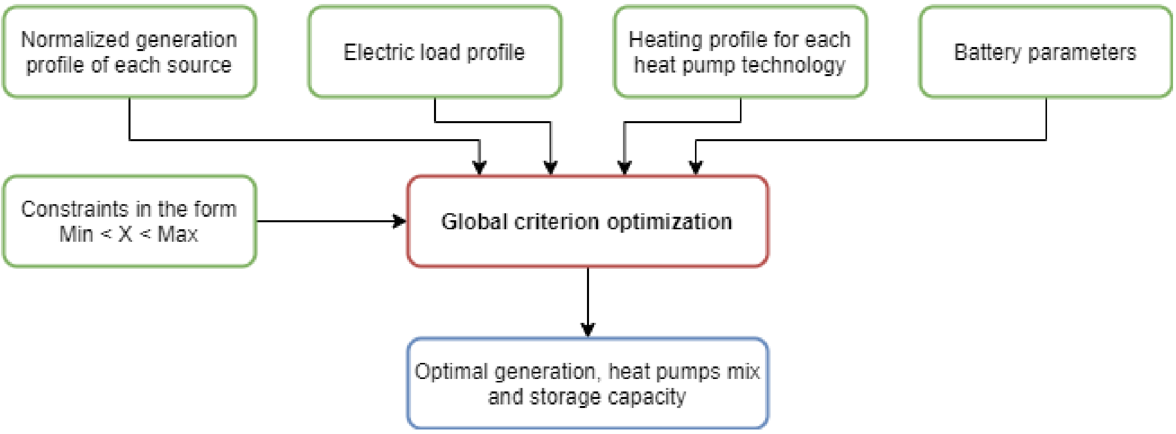


Figure 5.2 - Scheme of the global criterion optimization process

Applying the weighted sum method, instead, the optimization problem should have the following definition:

$$Objective_{Weight} = min\left[\alpha \cdot \frac{Fluxes_{Tot}}{Fluxes_0} + \beta \cdot \frac{Emissions_{Tot}}{Emissions_0} + \gamma \cdot \frac{NPC_{Tot}}{NPC_0}\right] \quad (5.37)$$

where α, β and γ are the multiplication factor to assign to each single objective function to define its weight in the overall function, defined such that their sum is unitary:

$$\alpha + \beta + \gamma = 1 \quad (5.38)$$

The results that are obtained are a mix of the solutions found by considering the objective functions singularly and depend on the coefficients α, β and γ of each scenario. Qualitatively, the higher the weight of an objective, the closer are the solutions to the ideal values of that same objective. Moreover, the problem will have the shape and the visualization of a ternary diagram. The logical scheme of the process is shown in Figure 5.3.

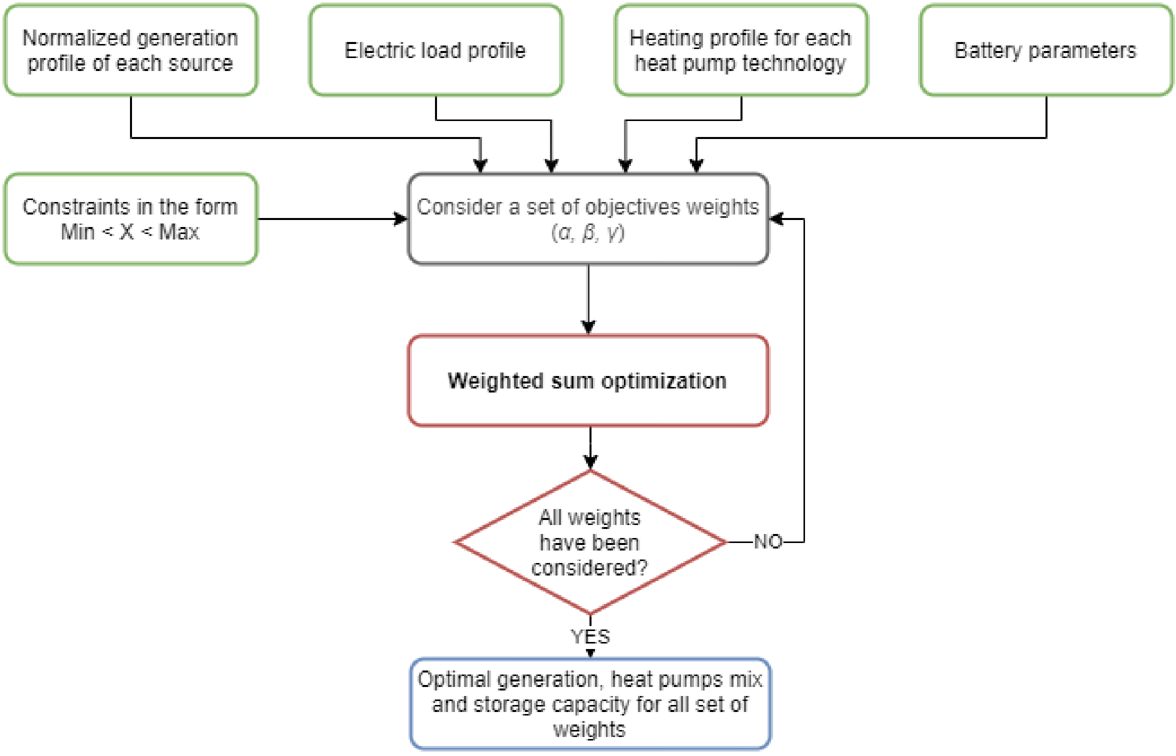


Figure 5.3 - Scheme of the weighted sum optimization process

Chapter 6
Case Study

A real-life study case has been adopted in order to test and validate the proposed model. The data are available thanks to a cooperation between Politecnico di Milano and Regione Valle d’Aosta. In this chapter, the geographic location and classification of the areas are first presented, followed by the generation profiles and the input load. A particular focus is placed on the building of the heating demand profile for each of the 74 municipalities of Valle d’Aosta that are later aggregated according to their area.

6.1 Geographic location

The model is applied to the case of Valle d’Aosta and, in particular, to each area defined by the set of municipalities afferent to a single transformation primary substation – i.e. belonging to a single area. In other words, the model simulates the introduction of community energy schemes in each area and is performed for each of them separately. More in detail, Valle d’Aosta is composed by 74 municipalities aggregated in 17 areas, the main data of which (2018) are provided in Table 6.1 and Table 6.2.

Table 6.1 - List and main data of the municipalities in Valle d'Aosta

Nr.	Municipality	Area	Unité des Communes	Climatic zone	Degree Days	Inhabitants
1	Allein	A14	Grand-Combin	F	3994	211
2	Antey-Saint-André	A3	Mont-Cervin	F	3843	571
3	Aosta	A12	Aosta	E	2850	34008
4	Arnad	A15	Evançon	E	2774	1254
5	Arvier	A16	Grand Paradis	F	3396	870
6	Avise	A16	Grand Paradis	F	3395	302
7	Ayas	A2	Evançon	F	4781	1360
8	Aymavilles	A1	Grand Paradis	E	2937	2066
9	Bard	A15	Mont Rose	E	2832	118

10	Bionaz	A14	Grand-Combin	F	4641	225
11	Brissogne	A8	Mont-Émilius	F	3516	960
12	Brusson	A2	Evançon	F	4453	893
13	Challand-Saint-Anselme	A15	Evançon	F	3791	753
14	Challand-Saint-Victor	A15	Evançon	F	3321	555
15	Chambave	A4	Mont-Cervin	E	2912	929
16	Chamois	A9	Mont-Cervin	F	4955	97
17	Champdepraz	A15	Evançon	E	2971	717
18	Champorcher	A15	Mont Rose	F	4373	399
19	Charvensod	A12	Mont-Émilius	F	3351	2430
20	Châtillon	A4	Mont-Cervin	F	3012	4631
21	Cogne	A16	Grand Paradis	F	4533	1351
22	Courmayeur	A5	Valdigne-Mont-Blanc	F	3926	2738
23	Donnas	A11	Mont Rose	E	2700	2501
24	Doues	A14	Grand-Combin	F	3996	509
25	Emarèse	A15	Evançon	F	3997	220
26	Etroubles	A14	Grand-Combin	F	4137	493
27	Fénis	A8	Mont-Émilius	F	3063	1792
28	Fontainemore	A17	Mont Rose	F	3372	429
29	Gaby	A17	Walser	F	3803	458
30	Gignod	A14	Grand-Combin	F	3505	1737
31	Gressan	A12	Mont-Émilius	E	2915	3378
32	Gressoney-La-Trinité	A6	Walser	F	4787	301
33	Gressoney-Saint-Jean	A6	Walser	F	4726	811
34	Hône	A15	Mont Rose	E	2778	1145
35	Introd	A16	Grand Paradis	F	3472	645
36	Issime	A17	Walser	F	3672	397
37	Issogne	A15	Evançon	E	2786	1373

38	Jovençan	A1	Mont-Émilius	E	2925	727
39	La Magdeleine	A3	Mont-Cervin	F	4698	107
40	La Salle	A7	Valdigne-Mont-Blanc	F	3734	2016
41	La Thuile	A13	Valdigne-Mont-Blanc	F	4394	802
42	Lillianes	A17	Mont Rose	F	3223	447
43	Montjovet	A15	Evançon	E	2785	1756
44	Morgex	A7	Valdigne-Mont-Blanc	F	3617	2112
45	Nus	A8	Mont-Émilius	F	3026	2964
46	Ollomont	A14	Grand-Combin	F	4266	162
47	Oyace	A14	Grand-Combin	F	4313	207
48	Perloz	A11	Mont Rose	F	3210	467
49	Pollein	A12	Mont-Émilius	E	2802	1539
50	Pontboset	A15	Mont Rose	F	3402	179
51	Pontey	A4	Mont-Cervin	E	2971	805
52	Pont-Saint-Martin	A10	Mont Rose	E	2735	3683
53	Pré-Saint-Didier	A13	Valdigne-Mont-Blanc	F	3738	1015
54	Quart	A12	Mont-Émilius	E	2778	4093
55	Rhêmes-Notre-Dame	A16	Grand Paradis	F	4820	79
56	Rhêmes-Saint-Georges	A16	Grand Paradis	F	4059	172
57	Roisan	A14	Grand-Combin	F	3327	1008
58	Saint-Christophe	A12	Mont-Émilius	E	2904	3499
59	Saint-Denis	A4	Mont-Cervin	F	3424	375
60	Saint-Marcel	A8	Mont-Émilius	E	2913	1344
61	Saint-Nicolas	A16	Grand Paradis	F	4032	317
62	Saint-Oyen	A14	Grand-Combin	F	4292	194
63	Saint-Pierre	A16	Grand Paradis	F	3263	3201
64	Saint-Rhémy-en-Bosses	A14	Grand-Combin	F	4511	318

65	Saint-Vincent	A4	Mont-Cervin	F	3053	4582
66	Sarre	A1	Grand Paradis	E	2953	4848
67	Torgnon	A3	Mont-Cervin	F	4466	569
68	Valgrisenche	A16	Grand Paradis	F	4728	190
69	Valpelline	A14	Grand-Combin	F	3462	598
70	Valsavarenche	A16	Grand Paradis	F	4544	169
71	Valtournenche	A9	Mont-Cervin	F	4524	2291
72	Verrayes	A8	Mont-Cervin	F	3744	1286
73	Verrès	A15	Evançon	E	2793	2633
74	Villeneuve	A16	Grand Paradis	E	2982	1285

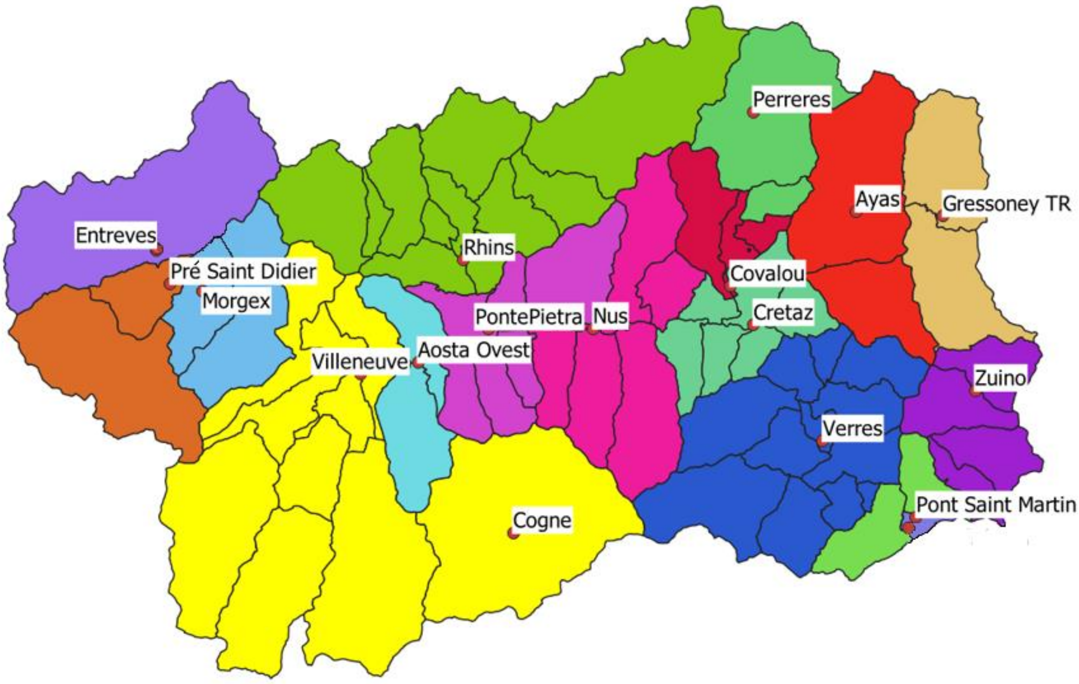


Figure 6.1 - Geographic distribution of the areas in Valle d'Aosta

Table 6.2 - Names of the areas in Valle d'Aosta

Area	Name
A1	*Aosta ovest*
A2	*Ayas*
A3	*Covalou*
A4	*Cretaz*
A5	*Entreves*

A6	*Gressoney*
A7	*Morgex*
A8	*Nus*
A9	*Perreres*
A10	*Pont Saint Martin*
A11	*Pont Saint Martin 2*
A12	*Aosta ponte pietra*
A13	*Pré Saint Didier*
A14	*Rhins*
A15	*Verres*
A16	*Villeneuve – Cogne*
A17	*Zuino*

6.2 Generation

6.2.1 Generators summary

The electricity generation data are provided by Regione Valle d'Aosta and are related to the plants connected in low or medium voltage. A summary of all reported power plants for each source is first presented. Then, the measured and normalized generation profiles are introduced.

For the hydro source, as for the case of all the regions in the North of Italy, all areas have a number of hydroelectric power plants ranging from 1 for area A1 *Aosta ovest* to 26 for area A16 *Villeneuve* and an overall installed capacity up to almost 27,000 kW for the latter (Figure 6.2). According to the data, it is interesting to show the installed capacity distribution for all the hydroelectric plants of the region, from which it is noticed that the majority are small-medium plants with installed capacity lower than 1,000 kW (Figure 6.3).

The solar source shows a higher number of power plants (Figure 6.4), but a smaller average capacity as shown in Figure 6.5.

For the cogenerative power plants, according to the data provided they are found in only four areas of seventeen total, namely in areas A8 *Nus*, A9 *Perreres*, A12 *Aosta ponte pietra* and A16 *Villeneuve* (Figure 6.6). In order to simplify the computation, for all CHP plants the heat generation part is neglected and only the electricity is considered in the model. This means that installing more CHP capacity does not contribute to satisfy part of the heating demand but only the electricity needs. This assumption can be verisimilar if the additional CHP plants are used in industrial configurations where the heat serves the industry needs but may be eventually improved in further developments of the model, where the thermal side could be more detailed.

For the wind plants, being Valle d'Aosta a region in the North of Italy where the wind source is not present as it is in the South, only four areas have nonnull installed capacity, but in three of them the capacities range from 3 to 25 kW, while only in area A4 *Cretaz* the installed capacity reaches as much as 3,000 kW (Figure 6.7).

Then, only three areas, A4 *Cretaz*, A7 *Morgex* and A8 *Nus*, exploit the bio – either biogas, biomass or bioliquids – potential with 6 plants and an overall installed capacity of about 2 MW (Figure 6.8).

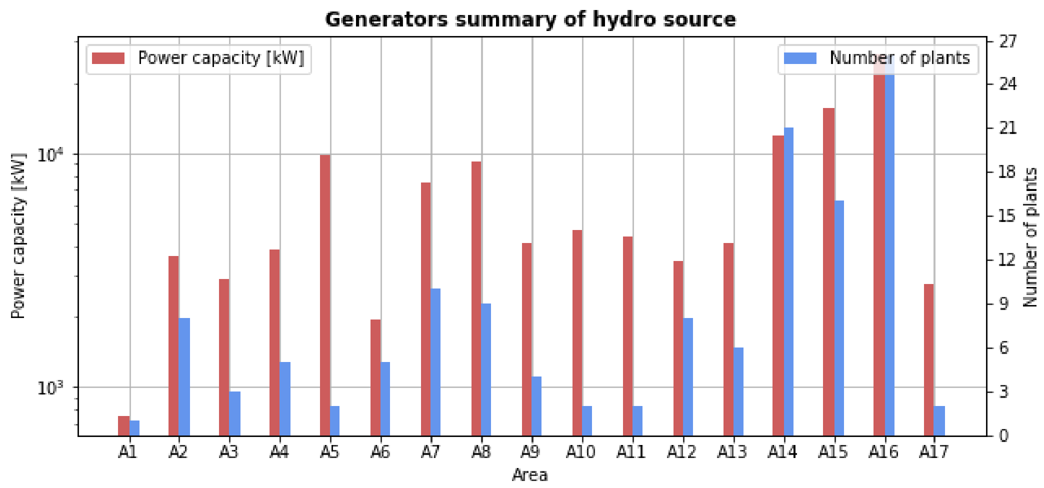


Figure 6.2 - Generators summary of hydro source (data by Regione Valle d'Aosta)

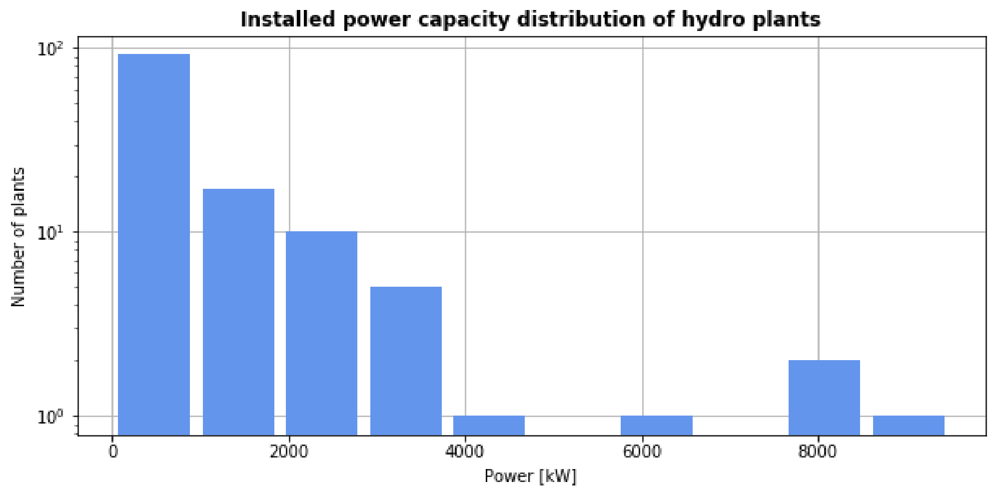


Figure 6.3 - Distribution of installed nominal power of hydro source (data by Regione Valle d'Aosta)

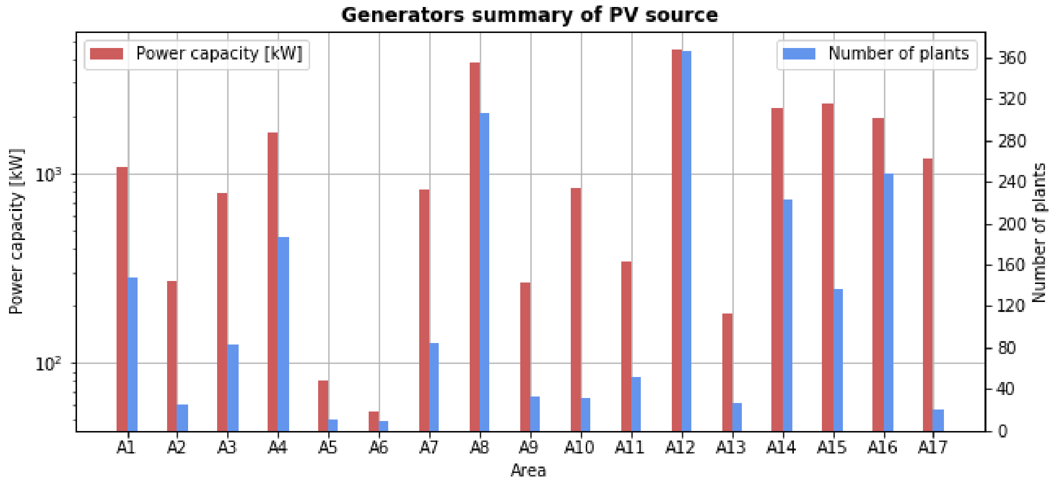


Figure 6.4 - Generators summary of PV source (data by Regione Valle d'Aosta)

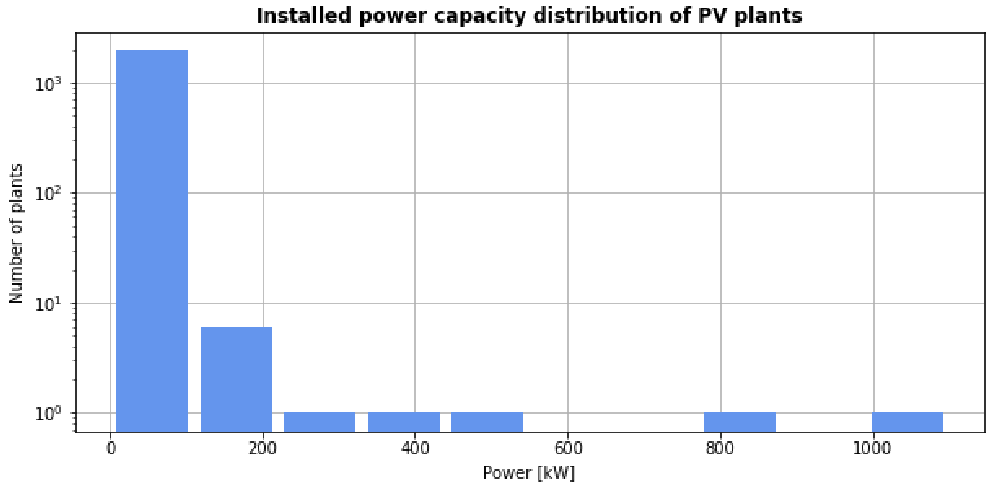


Figure 6.5 - Distribution of installed nominal power of PV source (data by Regione Valle d'Aosta)

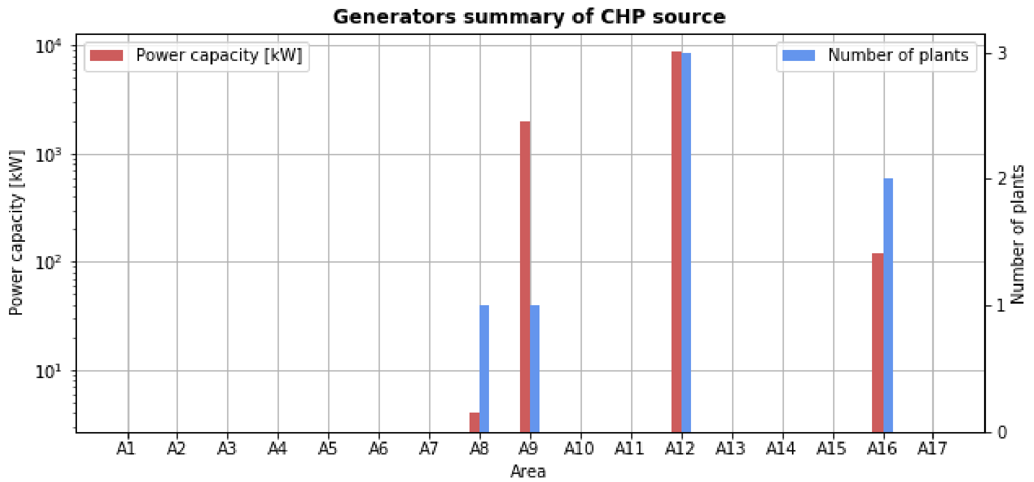


Figure 6.6 - Generators summary of CHP source (data by Regione Valle d'Aosta)

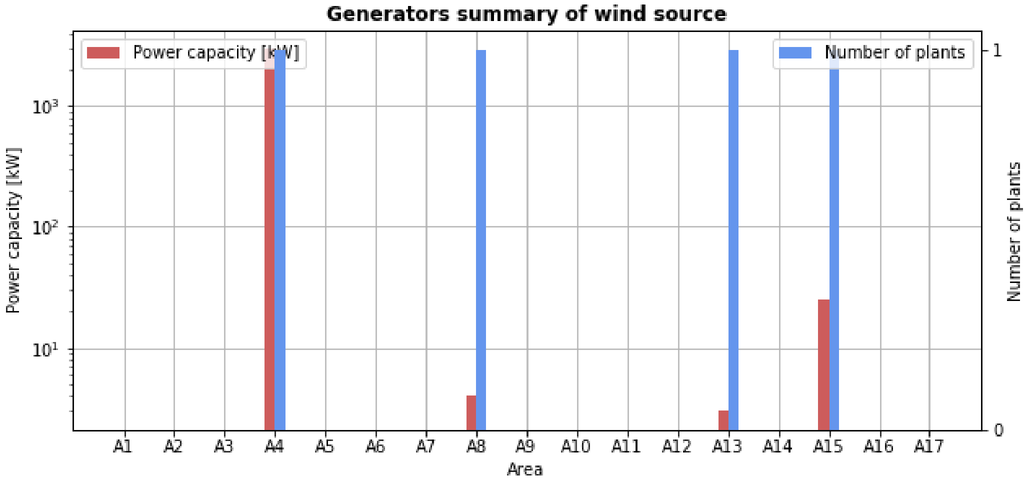


Figure 6.7 - Generators summary of wind source (data by Regione Valle d'Aosta)

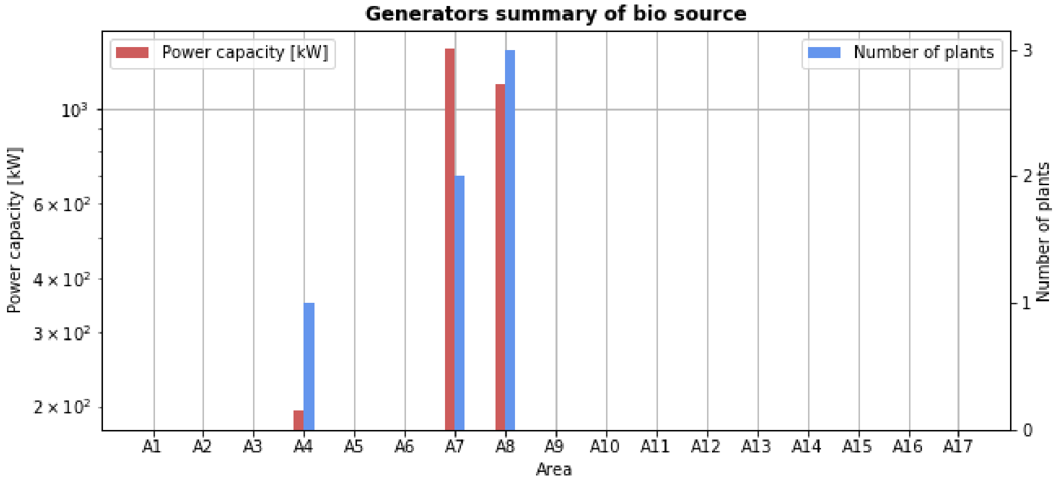


Figure 6.8 - Generators summary of bio source (data by Regione Valle d'Aosta)

6.2.2 Normalized generation

For each area m, the measured generation profiles for the year 2018 and the characteristics of all the plants j of every source k connected both in LV and MV are provided with a resolution of 15 minutes:

$$P_{j,k,m}(t), \;\; k = \{PV, \;\; Hydro, \;\; Wind, \;\; CHP, \;\; Bio, \;\; Thermal\}$$

where j is the considered plant, k the source and m the area where the plant is installed.

Of these profiles, only the ones of the plants with nominal capacity equal or higher than $55\ kW$ are selected since they are monitored at every time t and can better represent a typical generation profile when building the normalized production:

$$P_{j,k,m}^{Monitored}(t) = \left\{P_{j,k,m}(t), \;\; P_{j,k,m}^{Nominal} \geq 55kW\right\}$$

These profiles are used to obtain the overall generation profile of each source k in each area m by summing the profiles of all the plants j of source k in area m, according to the following equation:

$$P_{k,m}^{Overall}(t) = \sum_{j} P_{j,k,m}^{Monitored}(t) \tag{6.1}$$

Then, the normalized generation profiles $P_{k,m}^{Normalized}(t)$ for each source k in each area m, that corresponds to the power output of a power plant with capacity equal to 1 kW, are obtained by knowing the overall installed power capacity of the monitored plants $P_{k,m}^{Monitored,nominal\,power}[kW]$ – again, only the ones with capacity higher than 55 kW – for each source k in each area m:

$$P_{k,m}^{Normalized}(t) = \frac{P_{k,m}^{Overall}(t)}{\sum_j P_{j,k,m}^{Monitored,nominal\,power}} \tag{6.2}$$

For the purpose of the model, the normalized generation profiles $P_{k,m}^{Normalized}(t)$ for each source k in each area m are the input data for the generation modelling, therefore:

$$p_k(t) = P_{k,m}^{Normalized}(t)$$

where $p_k(t)$ is no longer a function of only the source k but depends on the analysed area m too. The normalized power profile is supposed to properly represent the behaviour of a given source in a given area.

It is important to notice that not all the areas have power plants of all the sources. For this reason, if an area has, for example, no wind power plants and, consequently, null normalized generation profile by the wind source, the model may understand that the wind source is not convenient to be installed in that area since, for every wind power capacity, the power output will always be null. In order to avoid this situation, the average regional normalized generation profile $\overline{p_k}(t)$ of each source k is calculated as the average profile of all the nonnull profiles of each area, such that if an area has null generation profile for a given source k, the average regional profile is used instead:

$$\overline{p_k}(t) = \frac{\sum_m P_{k,m}^{Overall}(t)}{\sum_{j,m} P_{j,k,m}^{Monitored,nominal\,power}} \tag{6.3}$$

The previous modelling is valid for all sources except for PV, as the normalized PV generation profile is corrected using the data provided by Renewables.ninja [67, 68]. In particular, the production of a 1 kW-capacity PV plant with 35° tilt angle, no tracking and 10% energy losses for each area was simulated, by selecting a latitude-longitude location corresponding to the centroids of the buildings in each area by using OpenStreetMap [69]. Knowing this, the normalized PV generation profile for each area with no plant with nominal capacity higher than 55 kW was corrected by multiplying every timestep per the simulated production and dividing it per the average simulated production by Renewables.ninja:

$$p_{m\,with\,no\,PV\,plant>55kW}^{PV}(t) = \overline{p_{PV}}(t) \cdot \frac{P_{PV,m}^{Simulated}(t)}{P_{PV,average}^{Simulated}(t)} \tag{6.4}$$

Lastly, notice that not all the monitored profiles provided by Regione Valle d'Aosta have been used to build the normalized production. In fact, some of them were observed to show either null or step profiles, or profiles without any physical meaning – i.e. PV plants producing during night-time – or with a trend totally different from other profiles of the same source. Some others with errors in a small number of days were simply fixed in those timesteps and left in the dataset. Lastly, others were showing null profiles during some prolonged time windows and have been removed from the calculations as well.

For the hydroelectric source, the 110 plants with nominal power capacity higher than 55 kW – that are the ones used to obtain the normalized generation profile – were also noticed to have some profiles very different in shape, intensity and variability. A detailed analysis of the plant types should be carried out in order to understand which profiles are related to a certain plant configuration but, in absence of these data, a simplified clustering was performed. In particular, three recurrent shapes were observed among the normalized generation profiles of the hydroelectric plants: the profiles with almost null generation during winter and a rapid increase of the curve in summer, reaching almost unitary normalized production, were classified as type "A" hydro; then, the profiles with a slightly higher generation during winter and an increase in summer with maximum normalized production around 0.8 were classified as type "B" hydro; lastly, the profiles with a quite constant normalized production at about 0.4 all along the year were classified as type "C" hydro. In order to assign each hydroelectric plant a type among A, B or C, one plant for each type was manually selected and their deviations from their average value was computed. For each of these three plants, then, the sum of the absolute values of the deviations in each timestep t was obtained and, calculating the same quantity for all others, each plant was assigned a type according to the proximity of the calculated quantity to each quantities of type A, B and C. In any case, some plants were manually assigned a type that better represented them.

The average regional normalized profiles for each source are shown in the following figures. Notice that in reality almost all areas m have their own normalized generation profiles for each source k. However, only the average regional profiles $\overline{p_k}(t)$ are shown for brevity.

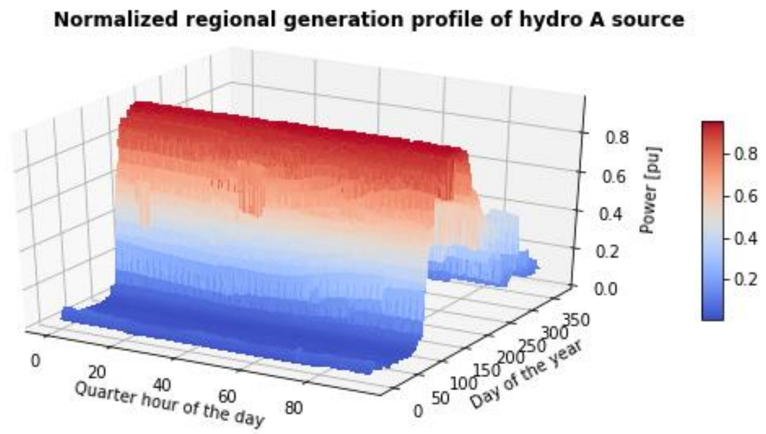


Figure 6.9 - Normalized production of hydro A source (calculations from data by Regione Valle d'Aosta)

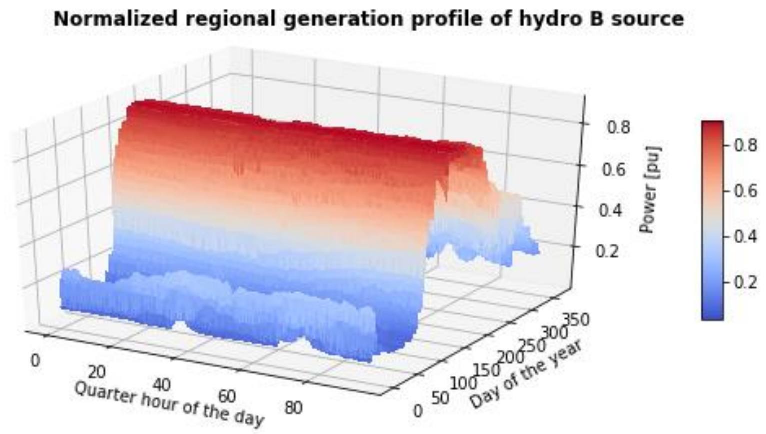


Figure 6.10 - Normalized production of hydro B source (calculations from data by Regione Valle d'Aosta)

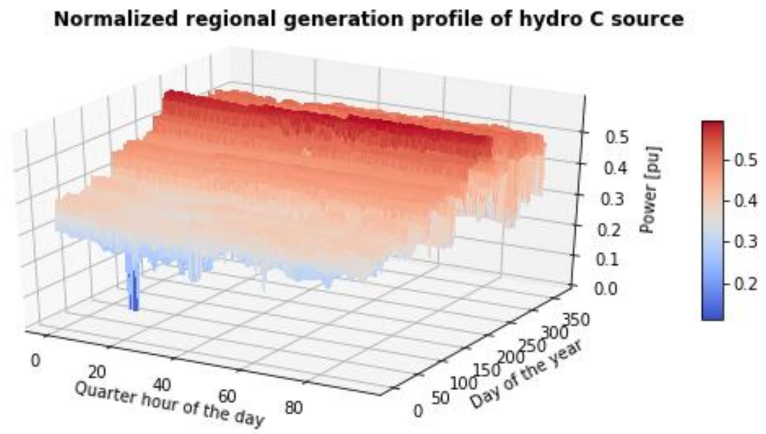


Figure 6.11 - Normalized production of hydro C source (calculations from data by Regione Valle d'Aosta)

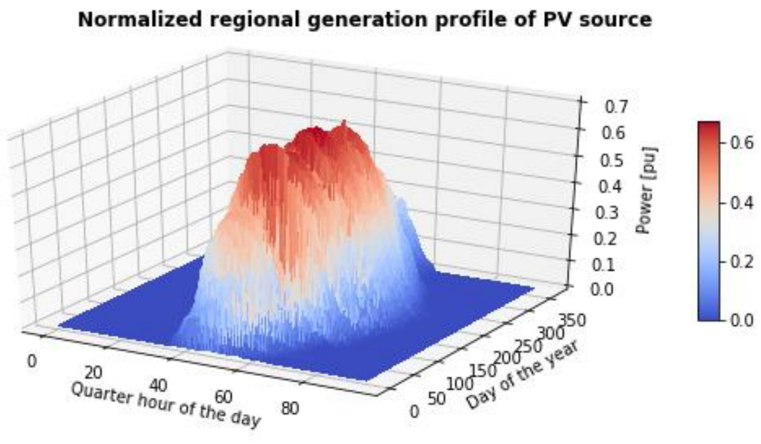


Figure 6.12 - Normalized production of PV source (calculations from data by Regione Valle d'Aosta)

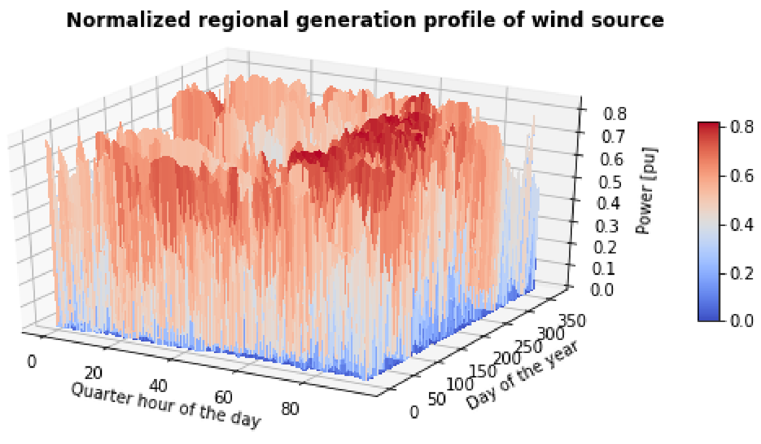


Figure 6.13 - Normalized production of wind source (calculations from data by Regione Valle d'Aosta)

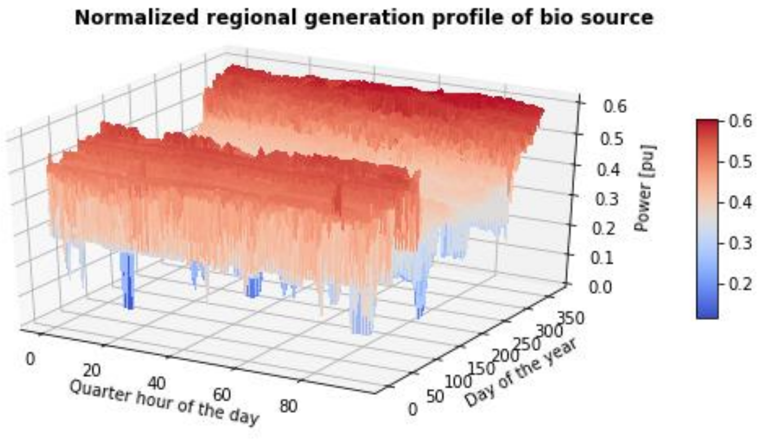


Figure 6.14 - Normalized production of bio source (calculations from data by Regione Valle d'Aosta)

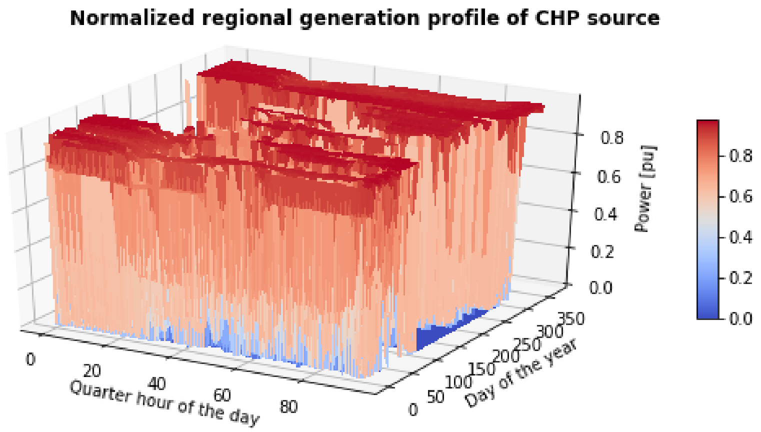


Figure 6.15 - Normalized production of CHP source (calculations from data by Regione Valle d'Aosta)

6.2.3 Costs and emissions

The costs for generation used in the model are reported in Table 6.3. The data from BEIS [49] and IEA [50] are used as reference and are related to the cost of a plant with capacity equal to 1 kW.

Table 6.3 - Costs data by source used in the model

Source	CAPEX [€/kW]	Fixed O&M [€/kW/year]	Variable O&M [€/MWh]
PV	1789	23	–
Hydro	5200	45	–
Wind	1673	37	–
CHP	4971	223	11
Biogas	7603	65	10

The emission factors are taken by the 2017 study commissioned by the EU Commission "Covenant of Mayors for Climate and Energy: Default emission factors for local emission inventories" [56]. The input data for the model are selected to be in an LCA approach, therefore the CO_2 emissions related to all the life cycle of the generation technologies are used rather than the direct operation emissions (Table 6.4).

Table 6.4 - Emissions data by source used in the model

Source	IPCC [tCO_2/MWh]	IPCCeq [tCO_2eq/MWh]	LCAeq [tCO_2eq/MWh]
Grid	0.343	0.344	0.424
PV	0	0	0.030

Wind	0	0	0.010
Hydro	0	0	0.006
CHP	0.363	0.363	0.363
Biogas	0.197	0.197	0.284

6.2.4 Constraints

A number of constraints is defined in the optimization problem. For what concerns the additional generation capacity to be installed by each source k in each area m, two different scenarios are introduced. The "unbounded potential" scenario defines a cap considered large enough to not constitute an excessively limiting constraint and is selected to be equal to 30,000 kW for each source k in each area m:

$$x_k^m \leq 30{,}000\ kW$$

The "bounded potential" scenario, instead, sets the caps for each technology as a function ϑ_k of the nominal power $P_{k,m}^{Nominal\ power}$ already installed in each area or in the Region, or according to the total roof surface S_m^{Roof}:

$$x_k^m \leq \vartheta_k \left(P_{k,m}^{Nominal\ power},\ \sum_m P_{k,m}^{Nominal\ power},\ S_m^{Roof} \right)$$

More in detail, for most sources the generation data are used to estimate the "bounded" potential in each area by assuming that the total generation capacity to be installed can at most double:

$$x_k^{m,max} = P_{k,m}^{Nominal\ power},\ \ k = \{Hydro\ A,\ \ Hydro\ B,\ \ Hydro\ C,\ \ CHP\}$$

For the bio and wind sources, instead, the maximum potential is defined at regional level, therefore having a maximum capacity for each area equal to the total installed generation capacity in the Region divided per the number of areas:

$$x_k^{m,max} = \frac{\sum_m P_{k,m}^{Nominal\ power}}{17},\ \ k = \{Bio,\ \ Wind\}$$

Lastly, the PV potential is estimated by considering the actual surface of the roofs in each area, assuming that the PV systems are only installed on the roofs rather than on the ground. For each municipality the surfaces of the buildings were obtained thanks to OpenStreetMap [69] and grouped according to the area. Only 20% of the total surface was assumed to be eventually covered with solar panels in a conservative assumption and a 250W solar panel with surface equal to 1.44 m^2 was considered. Therefore, the PV potential was calculated as:

$$x_k^{m,max} = 0.2 \cdot S_m^{Roof}[m^2] \cdot \frac{0.25}{1.44}\left[\frac{kW}{m^2}\right],\ \ k = \{PV\}$$

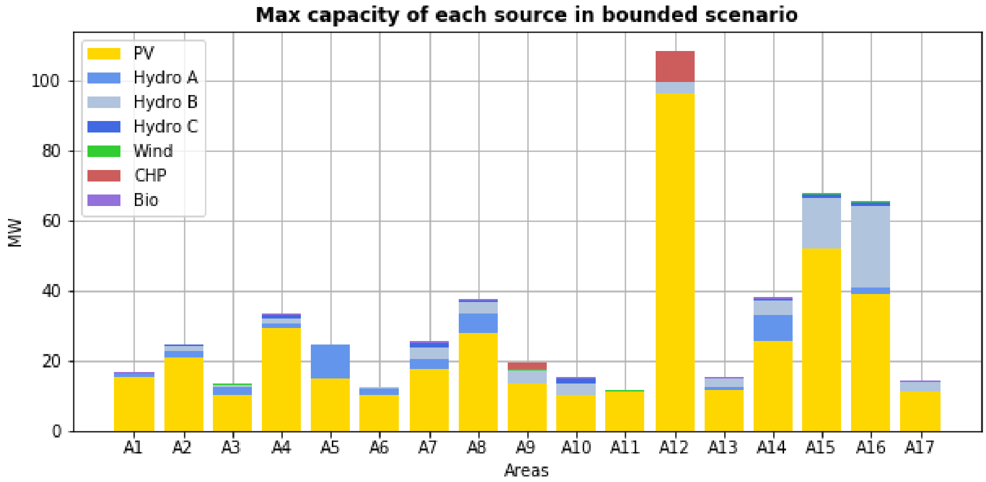


Figure 6.16 - Additional generation constraints in bounded scenario

This last scenario (Figure 6.16) generally results in lower potential for each source but, depending on the roof surface, it may eventually end up having a higher cap for PV. Of course, a more detailed analysis of the potential for each other source different from PV is needed but, due to the lack of real data required to perform such a calculation, only the PV availability was estimated.

6.3 Load

6.3.1 Transformers

The transit data, i.e. the electricity flux profiles of all the HV/MV transformers of the region, are provided by Regione Valle d'Aosta. In the region there is a total of 28 transformers HV/MV, but some of them are part of a single transformation primary substation afferent to a single area, such that the transformers can be grouped in 17 primary substations, one for each of the 17 areas (Table 6.5).

Table 6.5 - Transformers data (data by Regione Valle d'Aosta)

Transformer	Nominal power [MVA]	Area
IT009R00020238	25	A1
IT009R00020240	25	
IT009R00020201	16	A2
IT009R00020251	16	
IT009R00010229	16	A3
IT009R00020203	16	A4
IT009R00020204	16	

IT009R00020205	16	A5
IT009R00020206	16	A6
IT009R00020207	16	
IT009R00020208	16	A7
IT009R00020209	25	A8
IT009R00020210	16	A9
IT009R00020211	16	
IT009R00020212	16	A10
IT009R00020213	16	
IT009R00020214	16	A11
IT009R00020216	25	A12
IT009R00020217	25	
IT009R00020218	30	A13
IT009R00020219	25	
IT009R00020220	25	A14
IT009R00020221	25	
IT009R00020222	25	A15
IT009R00020223	25	
IT009R00020224	25	A16
IT009R00020225	16	
IT009R00020226	16	A17

More in detail, for each of the 28 transformers TR, the fluxes from and to the HV grid are known and the net transit can be calculated as:

$$L_{TR,m}(t) = L_{TR,m}^{in}(t) - L_{TR,m}^{out}(t) \tag{6.5}$$

where $L_{TR,m}^{in}(t)$ is the power coming from the HV grid and entering and $L_{TR,m}^{out}(t)$ the power exiting the area and entering the HV grid, so that $L_{TR,m}(t)$ is positive when entering the area and negative otherwise.

At this point, knowing which transformers pods are in each transformation primary substation of each area m, it is possible to obtain the transit of each area:

$$L_{EE}^{m}(t) = \sum_{pod}^{m} L_{TR,m}(t) \tag{6.6}$$

This is the electricity load used in the model for each area, therefore:

$$L_{EE}(t) = L_{EE}^{m}(t)$$

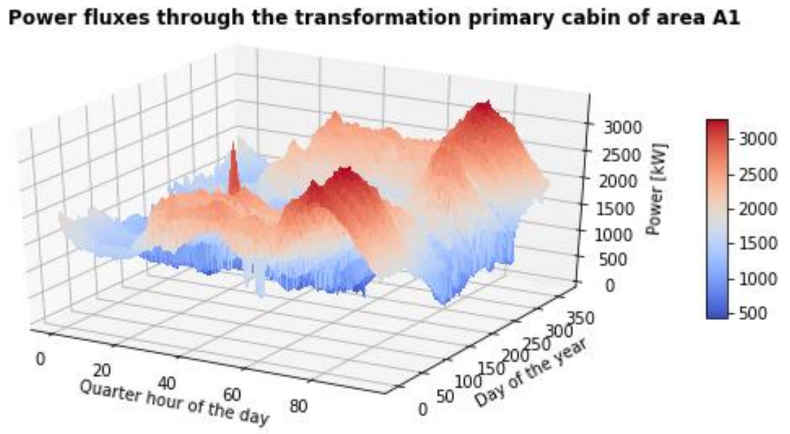


Figure 6.17 - Example of load profile (calculations from data by Regione Valle d'Aosta)

6.3.2 Costs

The average cost of electricity associated to the load is assumed according to FTT:Heat [28]. This value, however, can be used to define a constant electricity cost in the "Constant electricity cost" scenario or a variable one in the "Variable electricity cost" scenario. Therefore, in the first the cost is described as follows:

$$c_{El} = 0.231 \frac{€}{kWh}$$

Whereas in the variable scenario the electricity cost has a shape proportional to the PUN trend of 2018 provided by GME [53] around the same average value as before:

$$c_{El}(t) = 0.231 \cdot \frac{PUN_{GME}(t)}{PUN_{GME,average}} \tag{6.7}$$

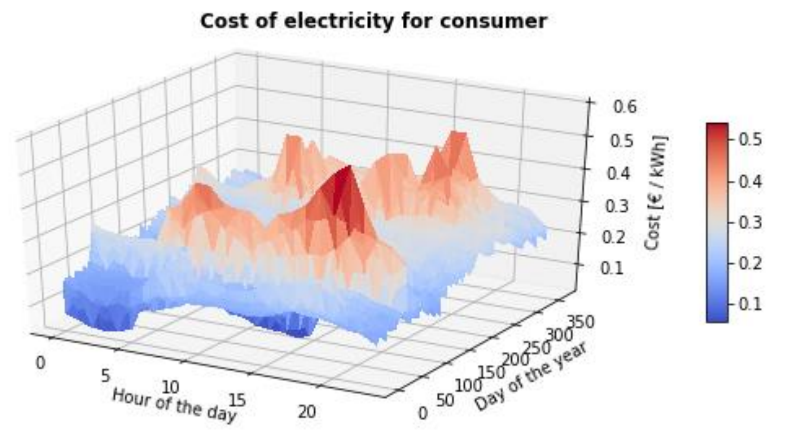


Figure 6.18 - Profile of cost for electricity in "variable electricity cost" scenario (calculations from [53])

Then, the historical series of the zonal price for the North region by GME [53] of the year 2018 is used to obtain a variable remuneration across the year:

$$p_{Zone}(t) = p_{North,GME}(t)\frac{€}{kWh}$$

Qualitatively, the trend of the zonal price is similar to that of the PUN, therefore having the same shape as $c_{El}(t)$ but with an average value about four times lower that the cost for the consumers.

6.3.3 Constraints

To model the constraints to the load, the data about each transformer nominal capacity provided by Regione Valle d'Aosta are used. In particular, if a single transformer is installed in a primary substation, the maximum residual profile is set to be within the nominal power:

$$Z_m^+(t) \leq max\left(P_{TR,m}^{nom}\right)$$
$$Z_m^-(t) \geq -max\left(P_{TR,m}^{nom}\right)$$

Instead, if more than one transformer is installed in a single primary substation of an area, the maximum fluxes are lower than the nominal power of the transformer with the highest nominal capacity increased by 20%, assuming that with two transformers in parallel they work simultaneously and not in backup configuration:

$$Z_m^+(t) \leq max\left(P_{TR,m}^{nom}\right) \cdot (1 + 20\%)$$
$$Z_m^-(t) \geq -max\left(P_{TR,m}^{nom}\right) \cdot (1 + 20\%)$$

For almost all areas these conditions are found to be very large, since the nominal power of the transformer(s) was much larger than the maximum load. For area A12 *Aosta ponte pietra*, on the contrary, the increase is set as 50% rather than 20% as the previous condition is found to be excessively limiting.

6.4 Heating

6.4.1 Heating demand

The model requires the generation of the heating demand profiles with a 15 minutes resolution for each of the 74 municipalities of Valle d'Aosta, and their aggregation according to the area they belong to. In this calculation only the non-electrified sources are considered, since the purpose is to obtain a profile to be electrified in an electrification scenario, while the already electrified forms of energy are comprised in the electric load described in the previous sections. All the data are provided by Regione Valle d'Aosta.

The first input is the total annual primary energy consumption $PE_{n,i}$ of the residential sector for each of the 74 municipalities n of the region and for each source of energy i. The peak bar in Figure 6.19 corresponds to the annual energy demand of the city of Aosta, which is the most populated city in all the region (see Table 6.1).

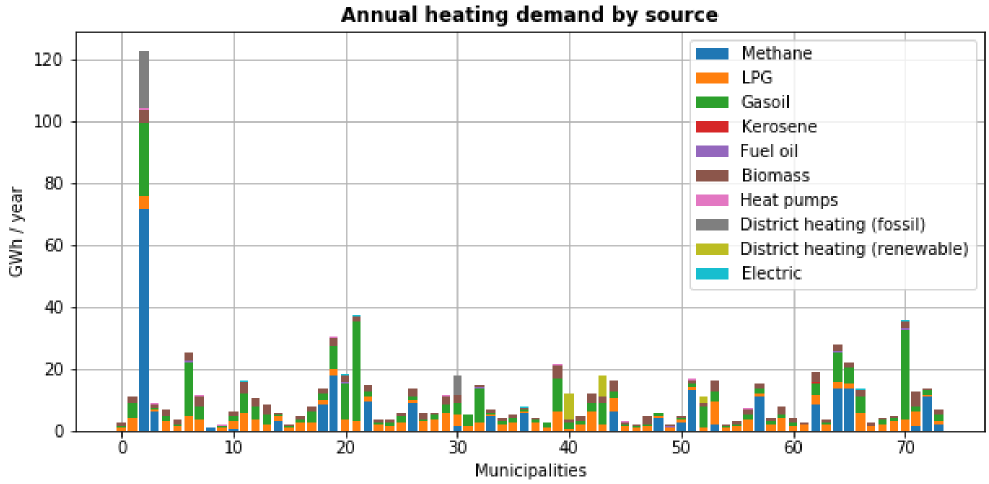


Figure 6.19 - Annual energy demand for heating by source and by municipality* (data by Regione Valle d'Aosta)

* For all the figures, please refer to Table 6.1 for the municipalities number.

The same values aggregated per area are shown in Figure 6.20. These, however, are not used in the model, as at this point the focus in at the municipality level. They will be used later when calculating the average cost for heating and emission factor for each area.

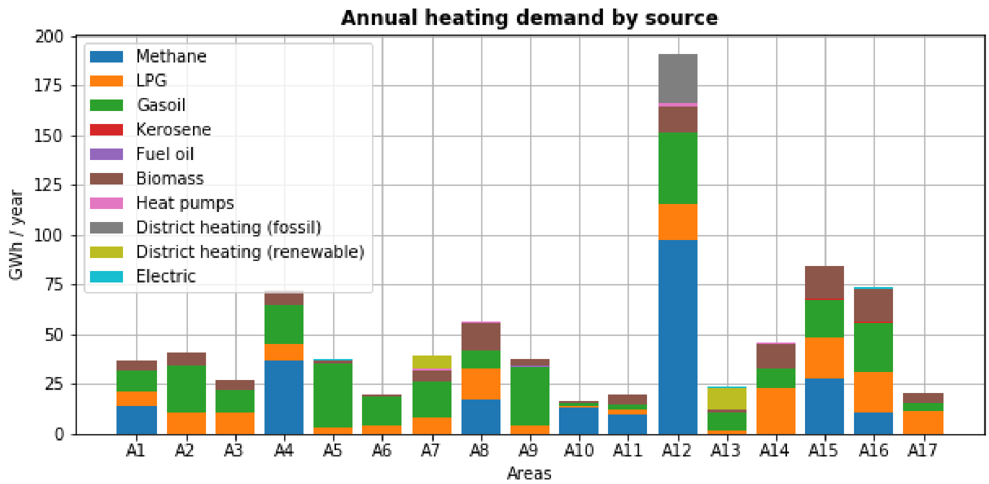


Figure 6.20 - Annual energy demand for heating by source and by area (calculations from data by Regione Valle d'Aosta)

Figure 6.21 shows the same values as fractions of the total energy demand for each municipality. It is possible to notice that only a small number of municipalities is connected to and use the methane pipelines, whilst the majority use especially GPL, gasoil and biomass for their heating needs.

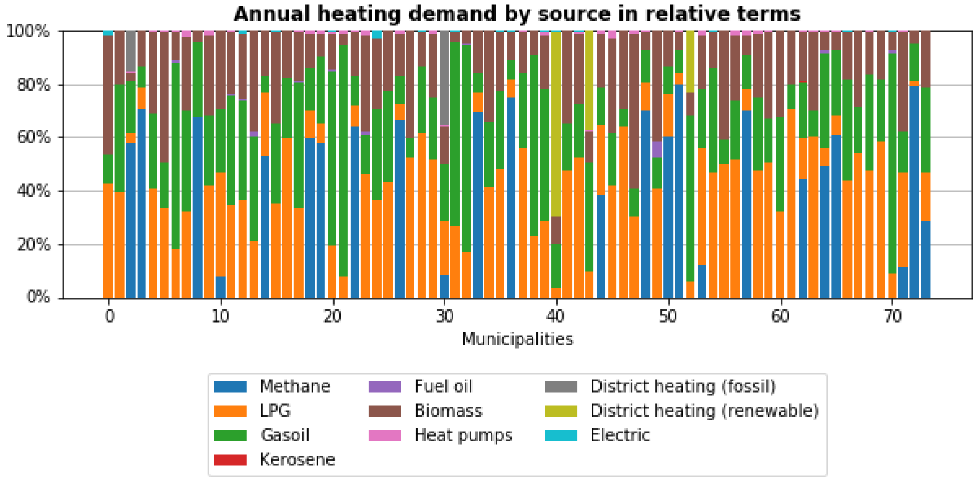


Figure 6.21 - Source mix of annual heating demand by municipality (calculations from data by Regione Valle d'Aosta)

The same values in per capita dimension vary a lot from municipality to municipality, ranging from around 3.6 MWh/year/capita for the city of Aosta to almost 28 for Valsavarenche (Figure 6.22).

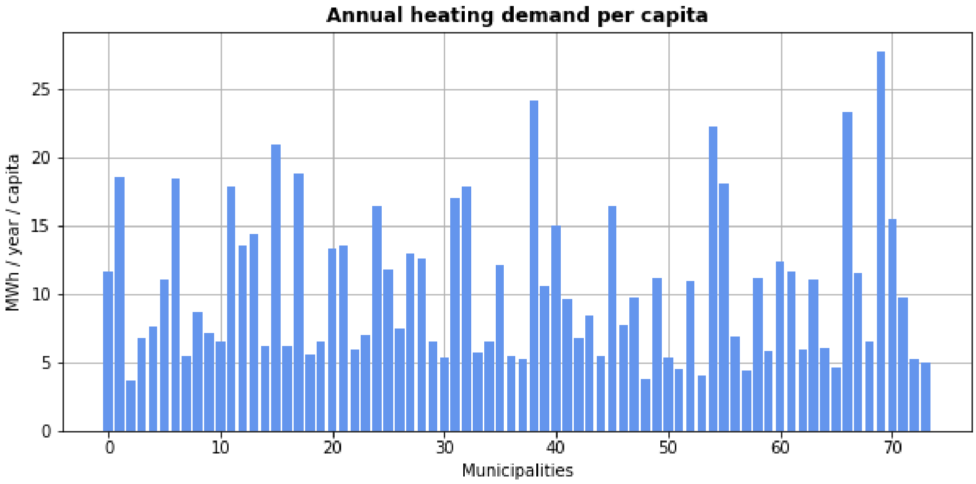


Figure 6.22 - Per capita annual energy demand for heating by municipality (calculations from data by Regione Valle d'Aosta)

Knowing the annual energy need, the values in the form of primary energy $PE_{n,i}$ have to be converted into useful energy $E_{i,n}$ by means of the average efficiency of conversion η_i of each source i, whose values suggested by the Region are shown in Table 6.6, therefore:

$$E_{n,i} = PE_{n,i} \cdot \eta_i$$

Table 6.6 - Average efficiency of sources for heating (data by Regione Valle d'Aosta)

Source	Efficiency
Methane	80%
LPG	
Gasoil	
Fuel oil	
Kerosene	
Biomass	70%
District heating	100%
Electric heating	
Heat pumps	135%

However, since the focus of the model is the electrification of heating, the voices *"Electric"* and *"Heat pumps"* are removed from the dataset as they are already electrified forms of energy – i.e. they are already comprised in the electric load – obtaining in this way the annual useful energy demand for each municipality n that can be electrified (Figure 6.23), which will be the one to be redistributed among the 15 minutes timesteps and converted into an additional electric load:

$$E_n = \sum_{i \neq \left\{ \begin{array}{c} Electric, \\ Heat\ pumps \end{array} \right\}} E_{i,n}$$

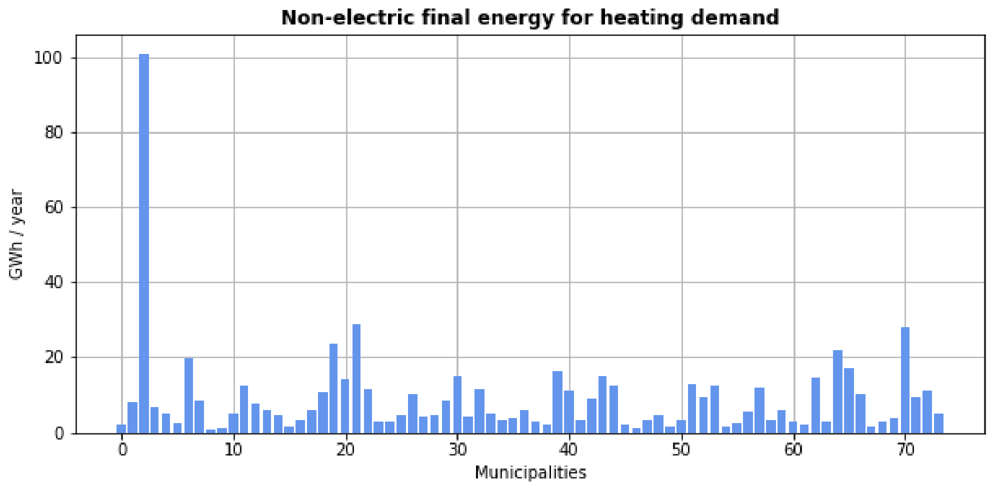


Figure 6.23 - Overall useful energy for heating of non-electric sources (calculations from data by Regione Valle d'Aosta)

6.4.2 Temperature profile

Another input is the hourly temperature profile for each municipality by Renewables.ninja [67, 68], of which the one of Allein is shown in Figure 6.24 as example.

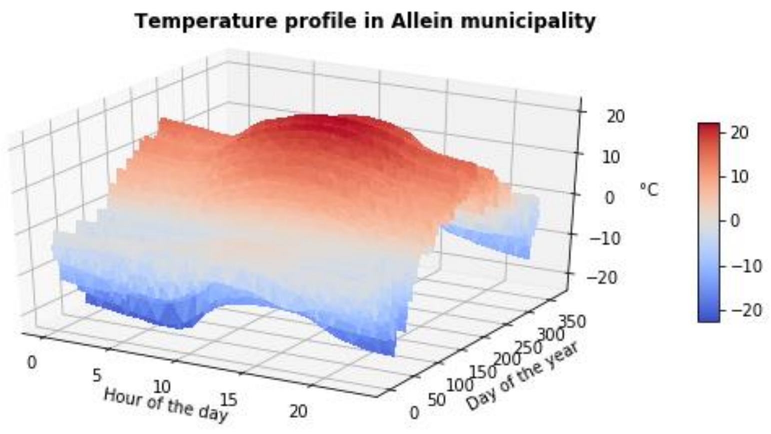


Figure 6.24 - Example of temperature profile [67, 68]

As it can be noticed in Figure 6.25 where the regional daily average and maximum and minimum temperatures in each hourly timestep are shown, the municipalities have different temperatures in each timestep, with a temperature difference from a municipality to another that can be as high as $10°C$.

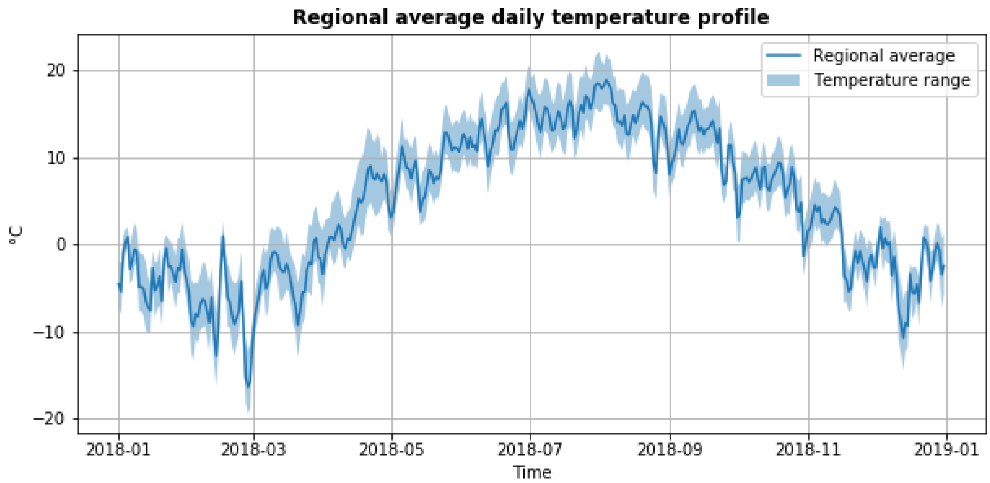


Figure 6.25 - Distribution of temperature profiles of the municipalities [67, 68]

However, as this input has a 1-hour resolution, a 15-minutes resolution has to be reached. In order to do so, each missing intra-hourly timestep temperature T is defined as dependant on the inter-hour timesteps t at its borders multiplied per a random factor RF assumed to be ranging from 0.95 to 1.05:

$$T_{@t+15\,minutes} = T_{@t} + (T_{@t+1\,hour} - T_{@t}) \cdot 0.25 \cdot RF$$
$$T_{@t+30\,minutes} = T_{@t} + (T_{@t+1\,hour} - T_{@t}) \cdot 0.50 \cdot RF$$
$$T_{@t+45\,minutes} = T_{@t} + (T_{@t+1\,hour} - T_{@t}) \cdot 0.75 \cdot RF$$

After this a 15-minutes resolution outdoor temperature profile $T(t)$ is obtained for each municipality n:

$$T_n(t)$$

6.4.3 Households characteristics

At this point the households are considered. The data provided by Regione Valle d'Aosta have a double classification of the households for each municipality n, either according to their construction period p or according to their occupation frequency f. For what concerns the classification of the households according to the construction period, the data provided by the Region see an important presence of buildings built during the period from 1945 to 1990 in all municipalities followed by the period before 1945 (Figure 6.26 and Figure 6.27).

The same data as fractions of the total number of households in each municipality show that households with both continuous and occasional occupation are equally present in the region, with different fractions depending on the municipality (Figure 6.28). This data will affect the resulting heating profile, since the households with occasional occupation require the domestic heating plant to be switched on and working only during weekends and holidays.

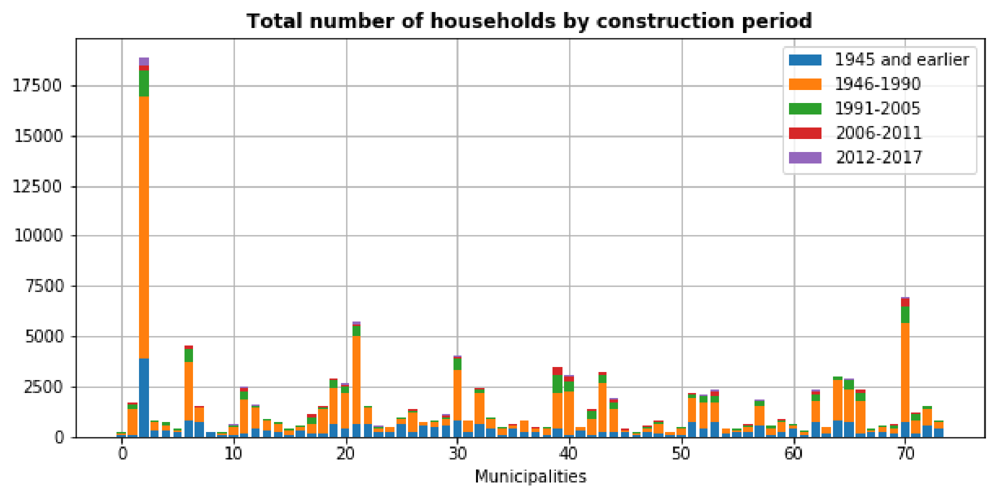


Figure 6.26 - Number of households by construction period and by municipality (data by Regione Valle d'Aosta)

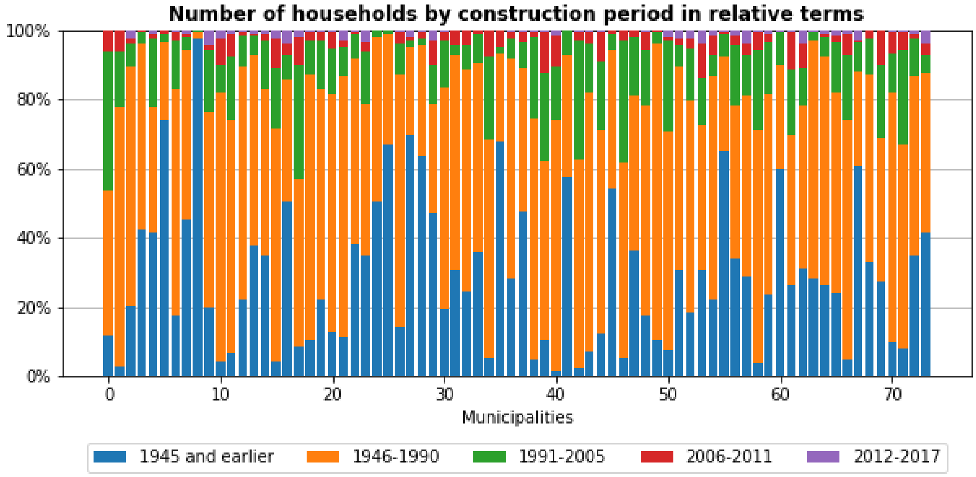


Figure 6.27 - Share of households by construction period and by municipality (data by Regione Valle d'Aosta)

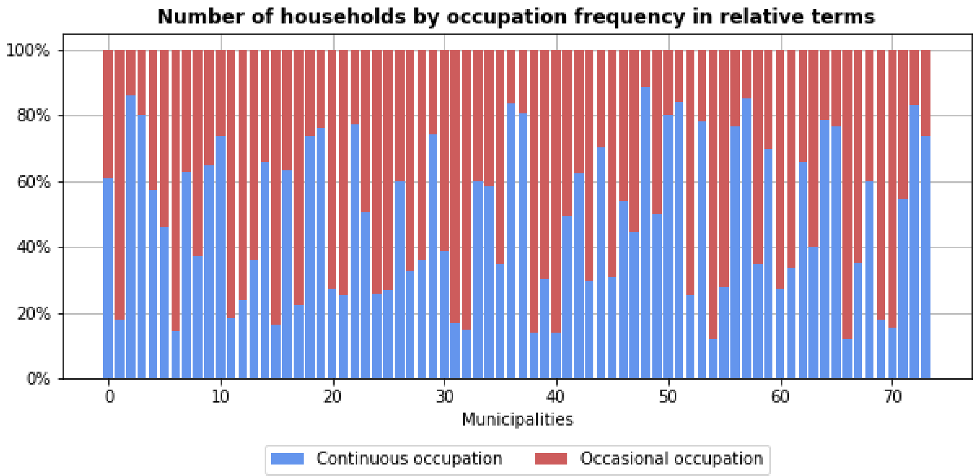


Figure 6.28 - Share of households by occupation frequency and by municipality (data by Regione Valle d'Aosta)

Therefore, for each municipality n the number of buildings for each construction period p and for each occupation frequency f are known (Figure 6.29):

$$N_{p,f,n}[-]$$

In the same way, Regione Valle d'Aosta provides the data for the total surface of the households as a function of the construction period p for each municipality n:

$$S_{p,n}[m^2]$$

In order to analyse deeper the average surface of the households, the average surface for each municipality and for each construction period are reported in Figure 6.30. In general, the households built between 2012 and 2017 show a slightly higher value of the surface with respect to the average 2011 and earlier one, equal to about 80 m^2. Notice that in this case, differently from the previous data, the average surfaces are given with a detail of only two construction periods.

Then, Regione Valle d'Aosta provides also the average annual energy consumption of the households for each construction period p and for each municipality n (Figure 6.31):

$$e_{p,n}\left[\frac{kWh}{year\cdot m^2}\right]$$

The average values for each municipality are observed to range from about 100 kWh/sqm/year for Aosta, to almost twice as much for other municipalities (Figure 6.32). This is the effect of primarily the climatic conditions of the zone, that affects the annual demand, and secondarily of the buildings construction period of the municipality. On the other hand, the average household heating demand specific to the surface decreases as the construction period becomes more recent, as shown in Figure 6.33.

Lastly, the average daily operating hours of the domestic heating plant for each municipality n and for each occupation frequency f are assumed by the Region (Figure 6.34):

$$hours[h]$$

In this way, the annual heating demand of each household for each construction period p, for each occupation frequency f and for each municipality n can be calculated (Figure 6.35):

$$E_{p,f,n}\left[\frac{kWh}{year}\right]=e_{p,n}\left[\frac{kWh}{year\cdot m^2}\right]\cdot S_{p,n}[m^2]\cdot\frac{hours[h]}{24[h]}$$

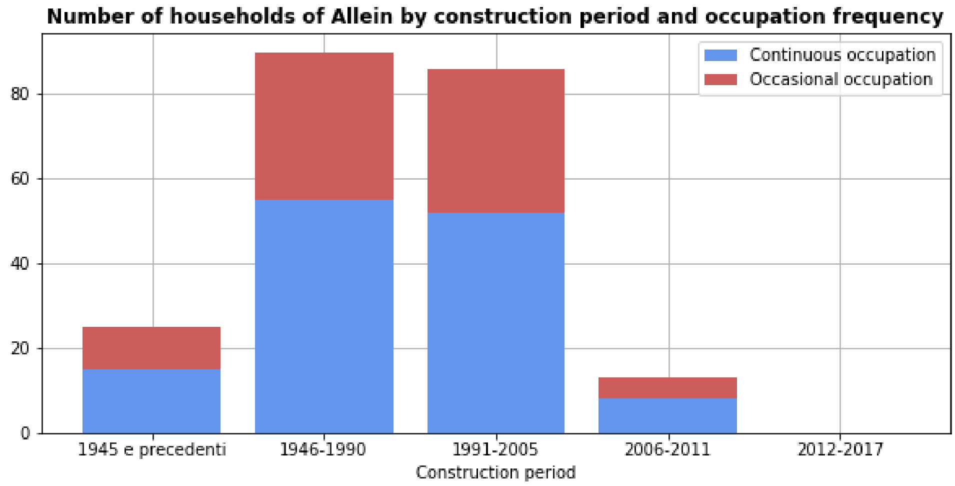


Figure 6.29 - Example of distribution of households by construction period and by occupation frequency for a municipality (data by Regione Valle d'Aosta)

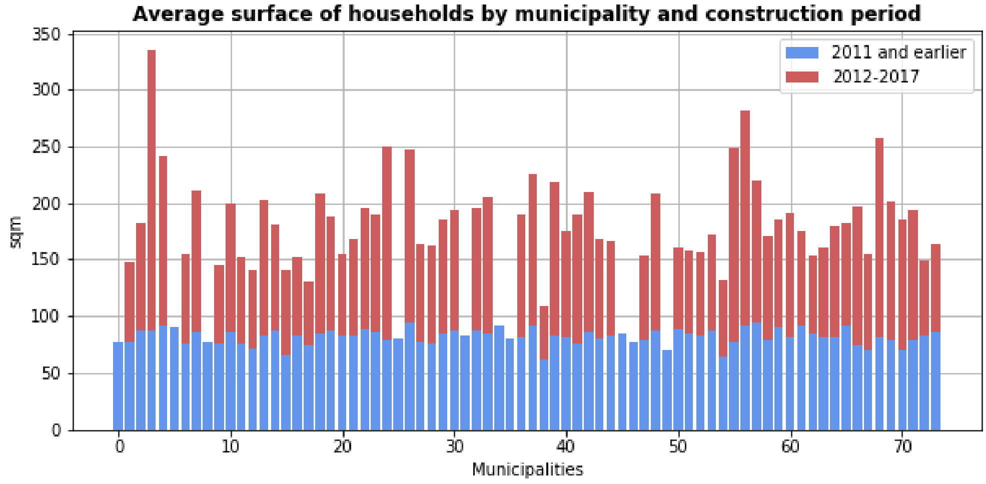


Figure 6.30 - Average surface of households by construction period and by municipality* (data by Regione Valle d'Aosta)

* Notice that the bars should be side by side, they are stacked instead being that the high number of municipalities did not allow a good virualization otherwise. The same holds for the other graphes as well.

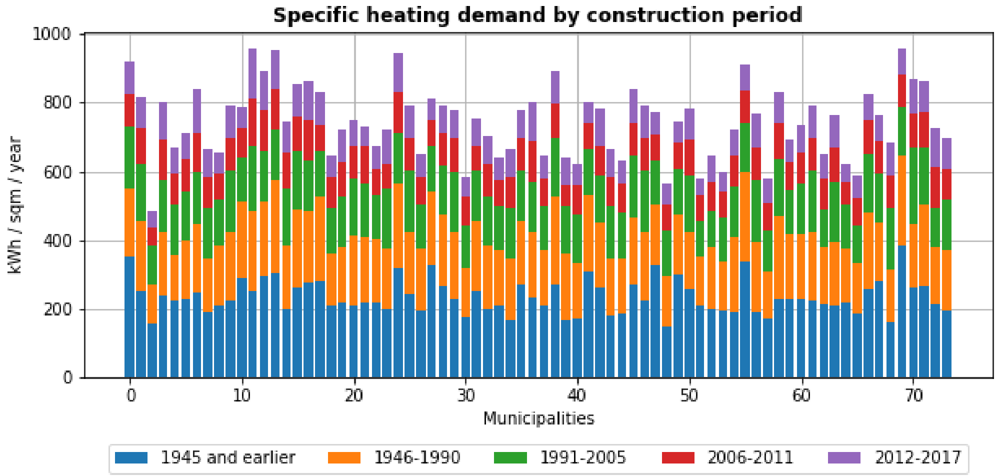


Figure 6.31 - Average annual energy demand specific to the surface of households by construction period and by municipality (data by Regione Valle d'Aosta)

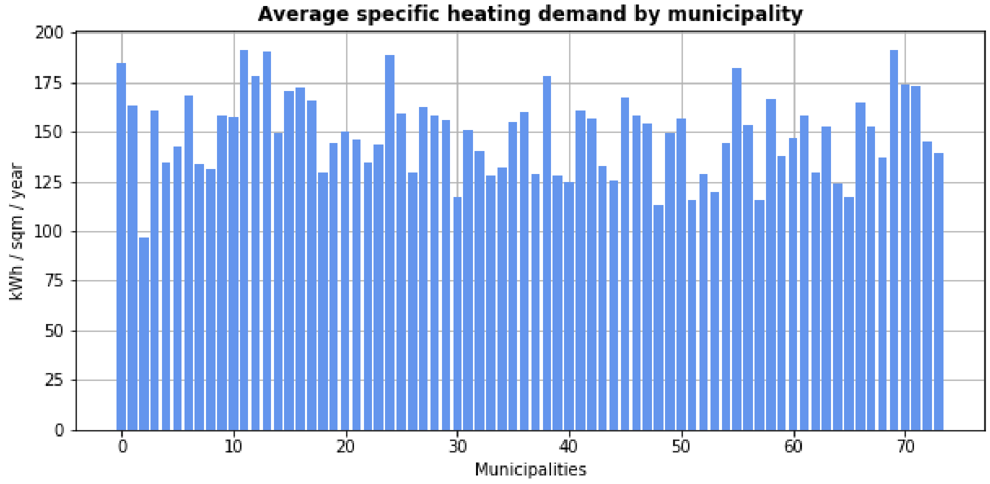


Figure 6.32 - Average annual energy demand for heating of households by municipality (data by Regione Valle d'Aosta)

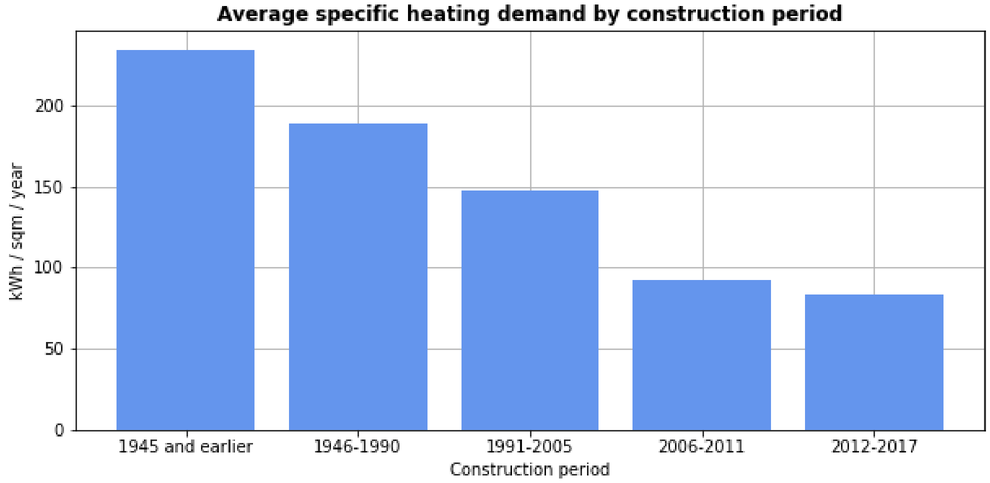


Figure 6.33 - Average annual energy demand for heating of households by construction period (data by Regione Valle d'Aosta)

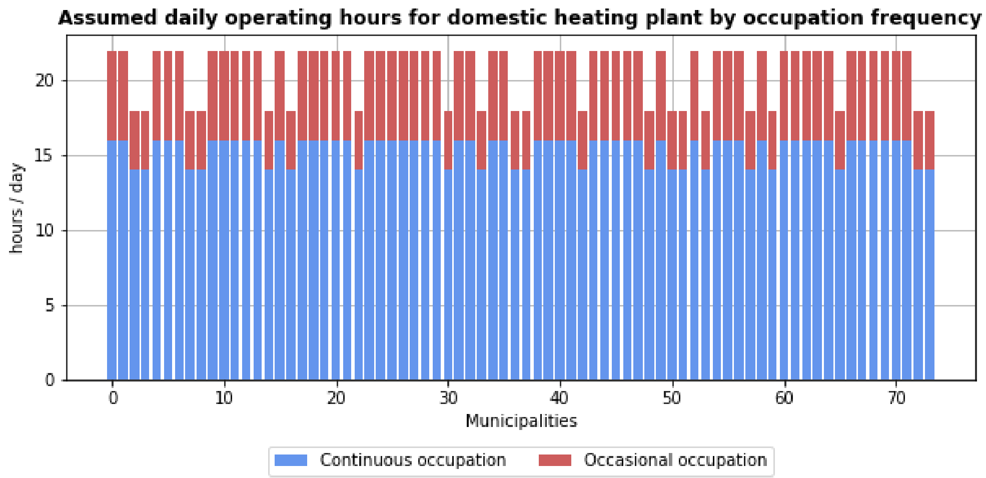


Figure 6.34 - Assumed daily operating hours for domestic heating plant by occupation frequency and by municipality (data by Regione Valle d'Aosta)

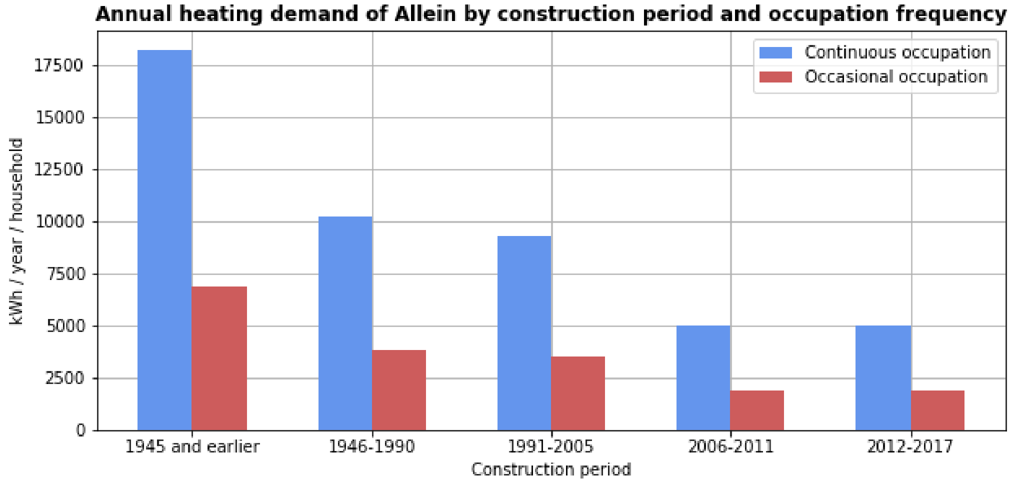


Figure 6.35 - Example of annual energy demand for heating of households by construction period and by occupation frequency for a municipality (data by Regione Valle d'Aosta)

6.4.4 Heating profile

Now it is possible to singularly simulate the heating behaviour of each household of each construction period p of each occupation frequency f in each municipality n. However, as the total number of households in Valle d'Aosta exceeds the 118.000 units, the computational cost of such method would be too heavy. A possible solution to this issue, that is the one used here, is to group a number of households assuming that the families living in one group of households have the same heating behaviour, in this way drastically reducing the time needed to generate the heating profile. The selected number of groups for each household type is 5 or, in other words, the number of households $N_{p,f,n}$ of a given construction period p and occupation frequency f in a given municipality n are grouped in 5 groups g, and all the families of the households of that group are assumed to have the same heating habits.

So, each group g of each construction period p, of each occupation frequency f and of each municipality n is singularly considered and its heating habits are simulated. First of all, a reference temperature $T_{ref,g,f,p,n}$ is randomly assumed, i.e. the indoor temperature below which the heating system is switched on and provides heat, for each group g according to the normative D.P.R. n. 74/'13 [17]:

$$T_{ref,g,f,p,n} = 20 \pm 2 \; [°C]$$

However, as $T_{ref,g,f,p,n}$ is related to the indoor reference temperature, a second reference temperature T'_{ref} needs to be assumed, representing the outdoor temperature below which the domestic heating plant starts working. Therefore, a temperature difference $\Delta T_{indoor-outdoor}$ is assumed to be

$$\Delta T_{indoor-outdoor} = 5 \; °C$$

and the outdoor reference temperature for each group g can be obtained:

$$T'_{ref,g,f,p,n} = T_{ref,g,f,p,n} - \Delta T_{indoor-outdoor}$$

Now, a temperature difference profile $\Delta T_{g,f,p,n}(t)$ is obtained:

$$\Delta T_{g,f,p,n}(t) = \begin{cases} T'_{ref,g,f,p,n} - T_n(t), & T'_{ref,g,f,p,n} > T_n(t) \\ 0, & T'_{ref,g,f,p,n} \leq T_n(t) \end{cases}$$

At this point, the profile $\Delta T_{g,n}(t)$ needs to be modified by taking into account that not for all the days of the year and hours of the day the domestic heating plant is turned on and working. First, for only the municipalities belonging to the climatic zone *E* (Table 6.1), $\Delta T_{g,n}(t)$ is set to be null during the period ranging from April 15th to October 15th according to the normative D.P.R. n. 74/'13 [17], and the heating period is assumed to end at 11 p.m., according to the same normative, therefore nullifying $\Delta T_{g,n}(t)$ after this hour:

$$\Delta T_{g,f,p,n}(t) = \begin{cases} \Delta T_{g,f,p,n}(t), & n \in Climatic\ Zone\ F \\ 0, & n \in Climatic\ Zone\ E,\ \ t > 23:00,\ \ Apr, 15 < t < Oct, 15 \end{cases}$$

Figure 6.36 shows the distribution of the number of Degree Days of all the municipalities, that is the number that defines the climatic zone for each municipality. In particular, the climatic zone *E* is associated to a number of Degree Days lower than 3000, while the climatic zone *F* to Degree Days higher than 3000, according to the normative D.P.R. n. 74/'13 [17].

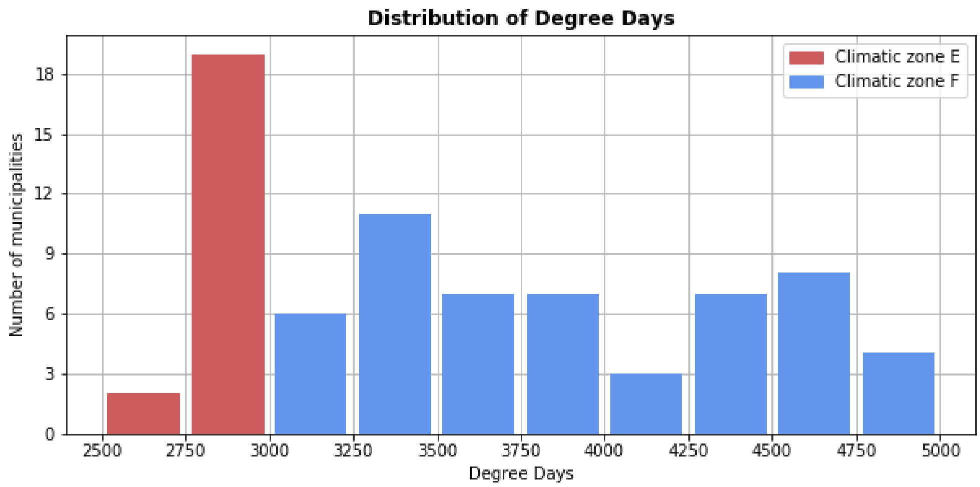


Figure 6.36 - Distribution of municipalities in Valle d'Aosta by Degree Days

At this point the daily use can be considered. According to the 2014 study by Istat [66], in Valle d'Aosta the duration of the working window of the domestic heating plant is different for different periods of the day. In particular, the afternoon (from 13 p.m. to 9 p.m.) has the longest working window with almost 5 hours, followed by the morning (from 5 a.m. to 1 p.m.) with about 4 hours and night-time (from 9 p.m. to 5 a.m.) with less than 2 hours (Figure 6.37).

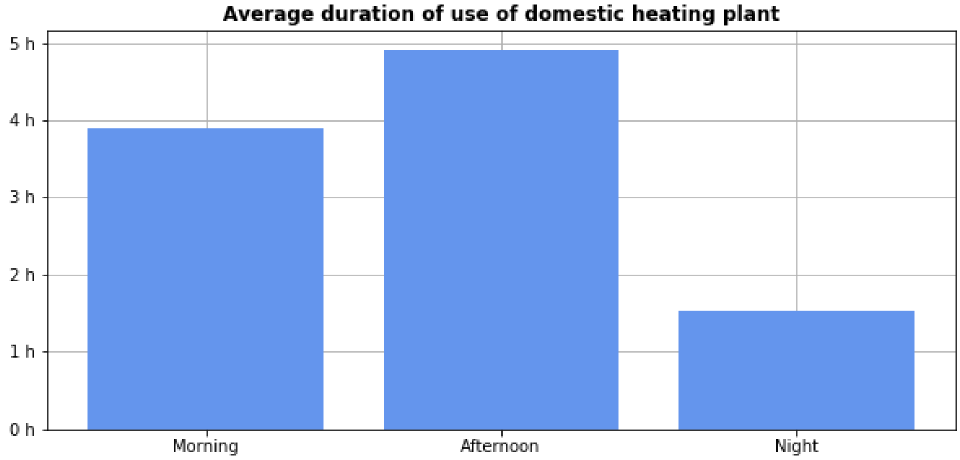


Figure 6.37 - Average duration of use of domestic heating plant in Valle d'Aosta [66]

As a consequence, by assuming the heating hours for each period of the day as the average value with a randomized 1-hour variation

$$\Delta h_{g,period} = \Delta h_{period} \pm rand(60\ minutes)$$

$$with\ period = \{morning,\ \ afternoon,\ \ night\}$$

and by randomly selecting the time in which the heating plant is turned on as the beginning time of the period plus a factor ranging from 0 to 8 hours with a triangular distribution with mode equal to 0

$$t_{g,period} = t_{period} + rand_{triangular}(480\ minutes)$$

the profile $\Delta T_{g,f,p,n}(t)$ can be modified to be null in the timesteps outside the operating hours, according to the following system of equations:

$$\Delta T_{g,f,p,n}(t) = \begin{cases} \Delta T_{g,f,p,n}(t), & t_{g,period} \leq t \leq t_{g,period} + \Delta h_{g,period} \\ 0, & t > t_{g,period} + \Delta h_{g,period}\ and\ t < t_{g,period+1} \end{cases}$$

At this point, the temperature difference profile can be modified knowing that in Valle d'Aosta the households use the domestic heating with a certain frequency [66]: 94% of households use the heating plants almost every day, 2.6% only a few days a week, 1.3% a few days a month and 2.1% only occasionally (Figure 6.38). Each group of households is randomly assigned a frequency of utilization and their heating habits are defined accordingly.

This process, however, depends on the occupation frequency of the considered group: if the frequency of the considered group of buildings is *"Continuative occupation"*, all probabilities are taken into account; if the frequency is "*Occasional occupation*" instead, the random probability selected by the model is set to be mandatorily one of the last three and the model is modified accordingly.

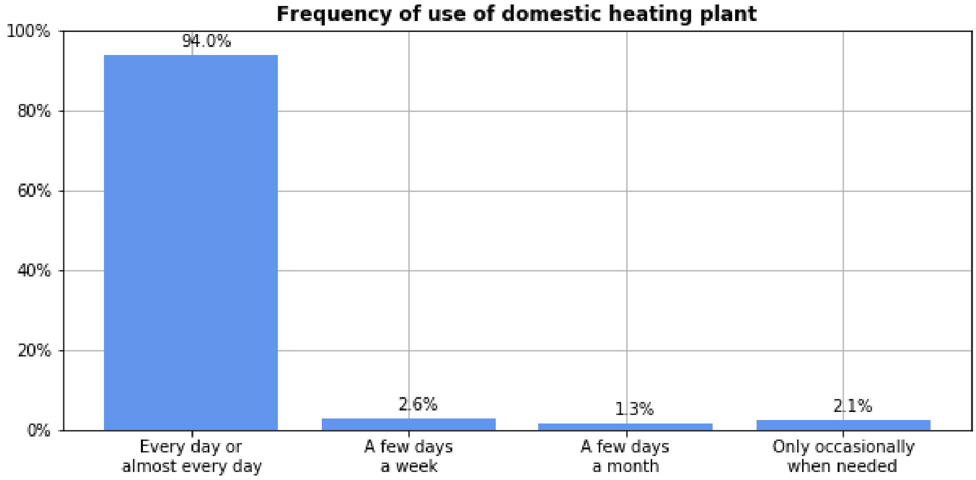


Figure 6.38 - Frequency of use of domestic heating plant in Valle d'Aosta [66]

For this reason, the temperature difference profile $\Delta T_{g,f,p,n}(t)$ of each group g is once again modified according to the probability described by the figure above. In particular, if the group g is assigned the frequency of utilization of the plant *"Every day or almost every day"*, the profile $\Delta T_{g,f,p,n}(t)$ is not modified. As stated above, this frequency of utilization can be assigned only to buildings with occupation frequency f *"Continuative occupation"*.

$$\Delta T_{g,f,p,n}(t) = \Delta T_{g,f,p,n}(t),\ \ with\ f = Continuative\ occupation$$

Instead, if the assigned frequency of utilization is *"A few days a week"*, for buildings with f *"Continuative occupation"* a number of days a week ranging from 4 to 5 is casually selected, after which each day is assigned to a weekday, obtaining in this way a list of weekdays $week_{ON}$ in which the heating plant is working. Under the assumption that the group use the heating plant in the same days of the week for every week, the profile $\Delta T_{g,f,p,n}(t)$ is modified such that the days of the week out of $week_{ON}$ have null heating demand. Instead, for buildings with f *"Occasional occupation"*, the groups of buildings is assumed to be occupied only during the weekend, therefore a number of days ranging from 2 to 3 is randomly selected and assigned to the weekdays Saturday and Sunday or Friday, Saturday and Sunday, respectively, obtaining again, assuming that the group of buildings is occupied in the same weekdays for all the weeks, a list of weekdays $week_{ON}$ in which the heating plant is working.

$$\Delta T_{g,f,p,n}(t) = \begin{cases} \Delta T_{g,f,p,n}(t), & t\ in\ week_{ON} \\ 0, & t\ not\ in\ week_{ON} \end{cases}$$

Similarly, if the assigned frequency of utilization is *"A few days a month"*, for buildings with f *"Continuative occupation"* a number of days ranging from 10 to 15 is casually selected and the same quantity of days of the month are casually chosen. For buildings with f *"Occasional occupation"* instead, they are still assumed to be occupied only during the weekend, with a number of weekends during the month randomly selected to be either 2 or 3.

$$\Delta T_{g,f,p,n}(t) = \begin{cases} \Delta T_{g,f,p,n}(t), & t \; in \; month_{ON} \\ 0, & t \; not \; in \; month_{ON} \end{cases}$$

Lastly, if the assigned frequency of utilization is *"Occasionally or when needed"*, a number of days ranging from 60 to 120 is casually selected, after which the same quantity of days of the year is casually chosen, obtaining a list of days of the year $year_{ON}$ in which the heating plant is working. Again, for buildings with f "*Occasional occupation*" they are assumed to be occupied only during the holidays, in particular from December 21st to January 8th, from April 1st to April 15th and from June 8th to September 8th.

$$\Delta T_{g,f,p,n}(t) = \begin{cases} \Delta T_{g,f,p,n}(t), & t \; in \; year_{ON} \\ 0, & t \; not \; in \; year_{ON} \end{cases}$$

At this point, the profile for heating $P'_{g,f,p,n}(t)$ of the group g can be obtained by multiplying the annual energy consumption $E_{p,f,n}$ of the building p with occupation frequency f in the municipality n per a factor represented by the share of the $\Delta T_{g,f,p,n}(t)$ on the sum of all the temperature differences at all timesteps $\sum_t \Delta T_{g,f,p,n}(t)$ and per the number of households in the considered group g:

$$P'_{g,f,p,n}(t) = E_{p,f,n} \cdot \frac{\Delta T_{g,f,p,n}(t)}{\sum_t \Delta T_{g,f,p,n}(t)} \cdot g$$

Now, the profiles of all the groups of a given building type p with occupation frequency f are summed up to obtain the total heating profile $P'_n(t)$ of all households in municipality n:

$$P'_n(t) = \sum_p \sum_f \sum_g P'_{g,f,p,n}(t)$$

Then, knowing the total annual non-electric energy demand for heating E_n of each municipality n, it is enough to multiply all the values in $P'_n(t)$ per a multiplication factor FM_n defined as:

$$FM_n = \frac{E_n \cdot 4}{\sum_t P'_n(t)}$$

where the factor 4 is due to the fact that the profile $P'_n(t)$ has a resolution of 15 minutes.

Consequently, the final non-electric power profile for heating $P_n(t)$ to be electrified for each municipality n can be obtained by multiplying each timestep for the factor FM_n:

$$P_n(t) = P'_n(t) \cdot FM_n$$

Lastly, all the profiles $P_n(t)$ of the useful thermal energy for heating of all the municipalities n are aggregated according to the area m they are part of:

$$P_m(t) = \sum_n^{Area} P_n(t)$$

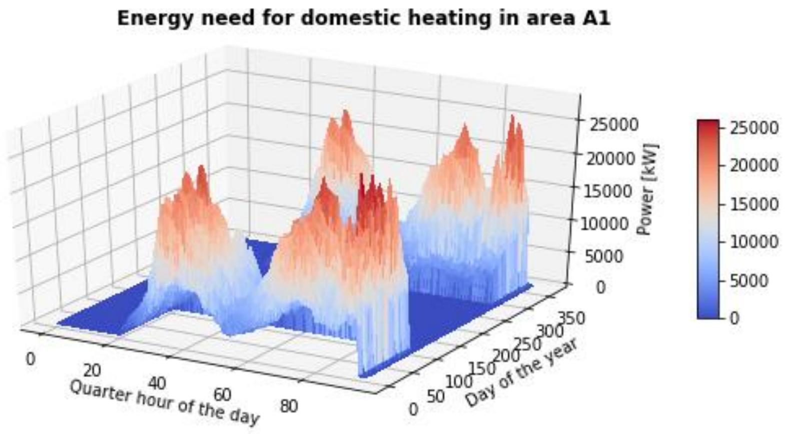


Figure 6.39 - Example of profile of heating

Some resulting profiles for the municipalities are shown. First, the heating profile for Allein in Figure 6.40 is an example of a climatic zone *F* municipality, for which the domestic heating plant has no hourly constraints and does not have to be switched off after 11 p.m. as for climatic zone *E*. Antey-Saint-André in Figure 6.41 is an example of a city with an important fraction of buildings that are occupied with an occasional frequency and, consequently, the profile shows to have a peak during the weekends. Lastly, Aosta is selected to show in Figure 6.42 that for municipalities in climatic zone *E* the profile is null after 11 p.m. and for all the hot season.

Figure 6.43, Figure 6.44 and Figure 6.45 zoom the obtained profiles in particular days.

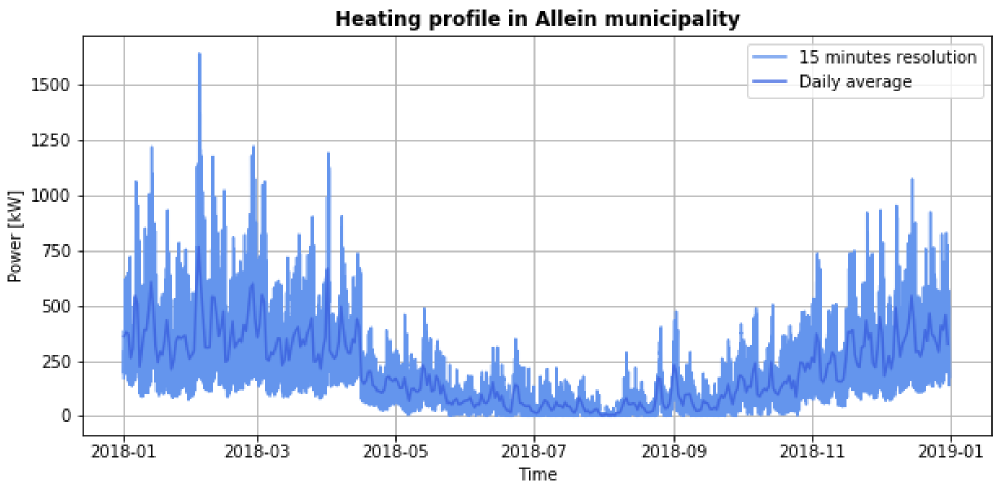


Figure 6.40 - Example of heating profile for a municipality in climatic zone *F*

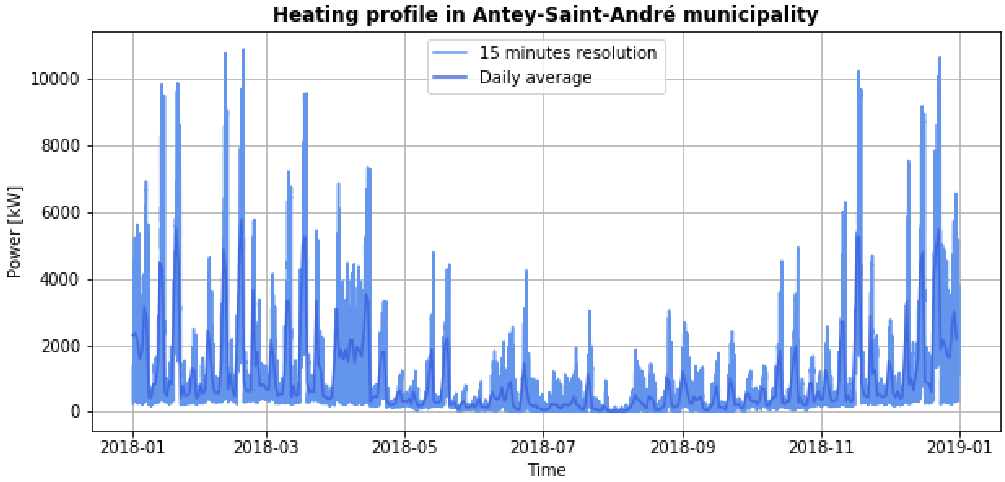


Figure 6.41 - Example of heating profile for a municipality with high share of households with occasional occupation

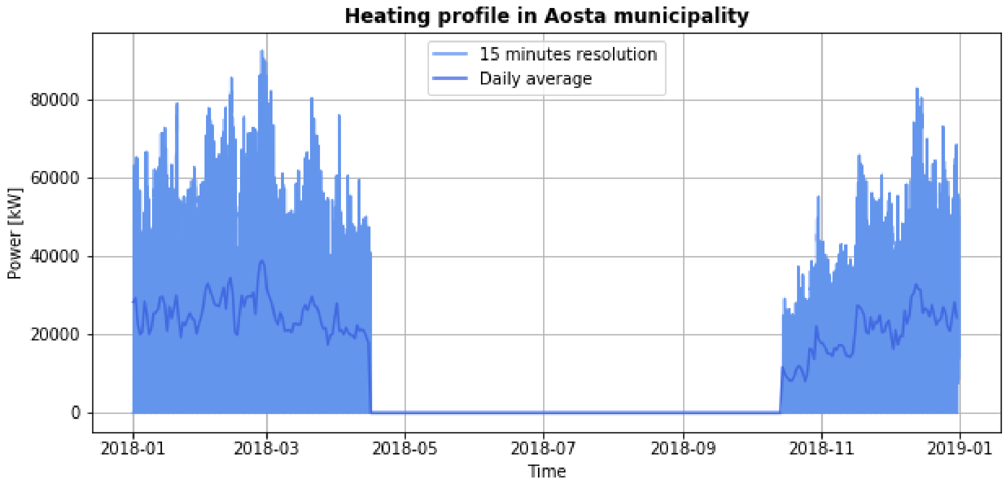


Figure 6.42 - Example of heating profile for a municipality in climatic zone *E*

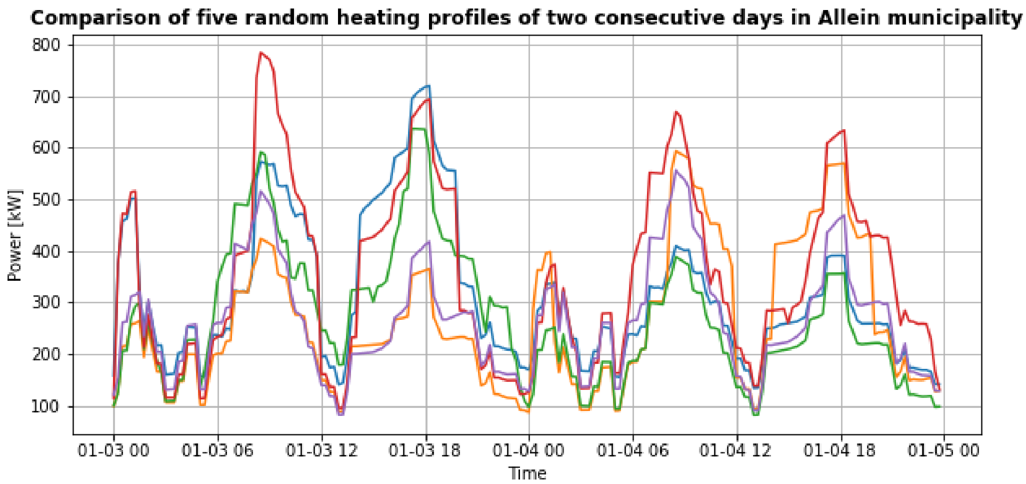


Figure 6.43 - Example of 5 random heating profile in two consecutive days in Allein municipality

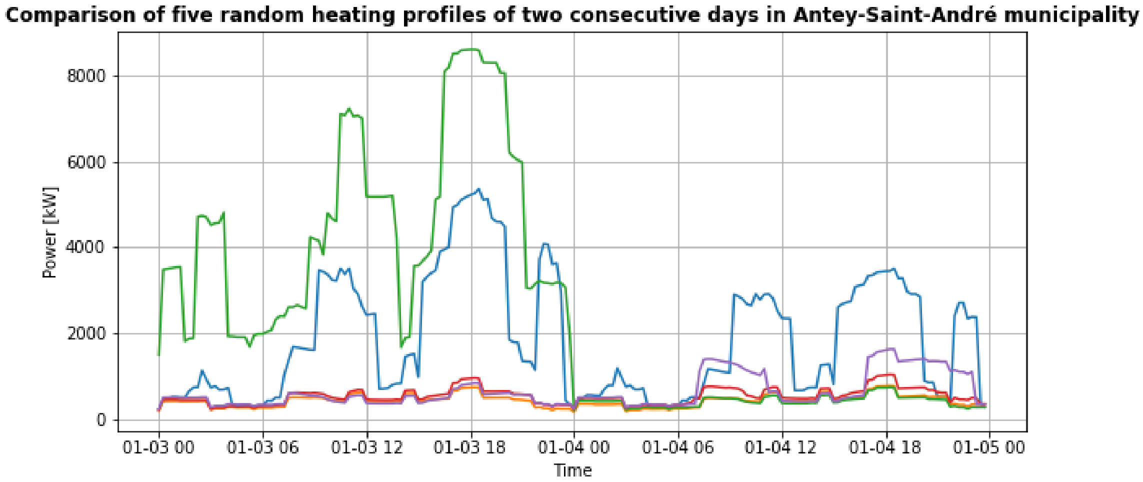


Figure 6.44 - Example of 5 random heating profile in two consecutive days in Antey-Saint-André municipality

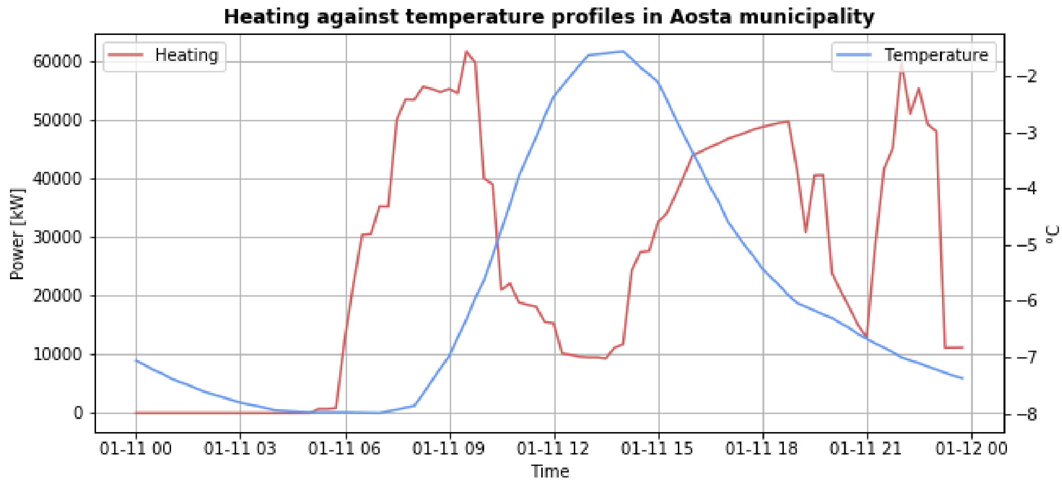


Figure 6.45 - Example of relation between temperature and heating profile in a municipality

6.4.5 Heating electrification

Now that the heating profile $P_n(t)$ for each municipality n is obtained, the next step is the electrification of heating by considering different heat pump technologies. As the market in Italy is almost exclusively made of ASHPs [24], only this category is considered in the model and, in particular, its two typologies of air-to-air and air-to-water heat pumps.

In order to model the Coefficient Of Performance, the study "A review of domestic heat pumps" by Iain Staffell (2012) [25] is used. By analysing the manufacturer's data and field trials of a number of air source heat pumps, the study was able to obtain a relation between COP and source-outlet temperature difference, expressed as:

$$COP(\Delta T) = 6.81 - 0.121 \cdot \Delta T + 0.00063 \cdot (\Delta T)^2 \qquad (6.8)$$

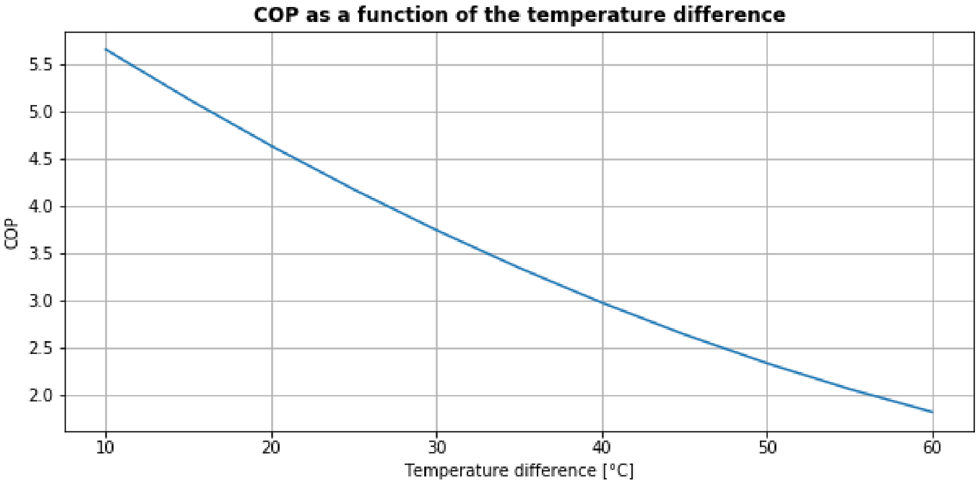


Figure 6.46 - Trend of COP with the temperature difference [25]

However, if the temperature of the heat source is the same for both air-to-air and air-to-water heat pumps, being the external air temperature in both cases, the maximum temperature to be reached to provide the heating power needed at one moment is different and ranges from 25 to 35 °C for direct air heating (air-to-air heat pumps) and from 30 to 45 °C for underfloor heating (air-to-water heat pumps) [25]. Therefore, in order to decrease the computational cost of the model, an average value for the outlet temperature is selected for each technology, in particular:

$$T_{outlet} = 30°C\ for\ air - to - air\ heat\ pumps$$
$$T_{outlet} = 40°C\ for\ air - to - water\ heat\ pumps$$

By assuming this, at equal outdoor temperature the COP for air-to-air will be higher than the COP for air-to-water heat pumps, therefore having a lower electric power demand for air-to-air with respect to air-to-water.

Actually, there can be some other configurations where the air-to-water technology does not use an underfloor heating system, but rather the conventional or large-area radiators to provide the heat demand needed at one moment. In this configuration, however, the outlet temperature has to be much higher and equal to 45-60 °C and 60-75 °C for large-area and conventional radiators respectively, increasing the temperature difference and decreasing the COP [25]. The assumption made in this model is that all air-to-water heat pumps use an underfloor heating system, in spite of its higher economic impacts.

At this point it is possible to obtain the COP as a function of the external air temperature for each technology j:

$$COP_j(T_{outdoor}) = 6.81 - 0.121 \cdot (T_{outlet,j} - T_{outdoor}) + 0.00063 \cdot (T_{outlet,j} - T_{outdoor})^2$$

However, knowing the temperature profile $T_n(t)$ for each municipality n, it is possible to obtain the COP_j for each technology j as a function of time t:

$$COP_j(t) = 6.81 - 0.121 \cdot \left(T_{outlet,j} - T_n(t)\right) + 0.00063 \cdot \left(T_{outlet,j} - T_n(t)\right)^2$$

$$with\ j = \{Air - to - air,\ \ Air - to - water\}$$

Consequently, it is now possible to obtain the electrical power $P_{n,j}(t)$ needed to cover the heating power demand $P_n(t)$ for each technology j and for each municipality n:

$$P_{n,j}(t) = \frac{P_n(t)}{COP_j(t)}$$

Lastly, all the heating profiles $P_{n,j}(t)$ of all the municipalities n are aggregated according to the area m they are part of, for which an example related to area A4 *Cretaz* is shown in Figure 6.47:

$$P_{m,j}(t) = \sum_{n}^{Area} P_{n,j}(t)$$

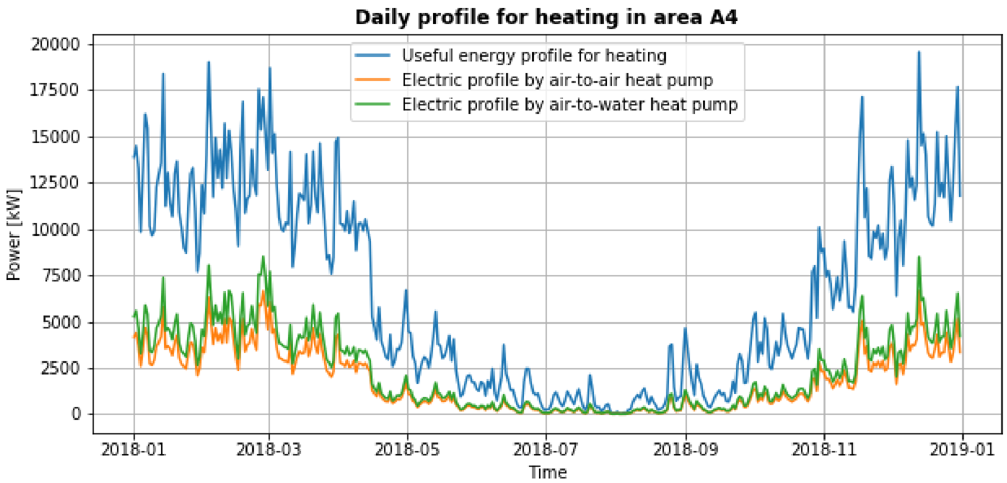


Figure 6.47 - Comparison of heating profile with two heat pumps technologies

6.4.6 Costs and emissions

The costs of the heat pumps are also given. According to the 2017 study "A technical analysis of FTT:Heat – A simulation model for technological change in the residential heating sector" by the European Commission [28], the air-to-air heat pump has lower specific investment cost and higher specific fixed O&M cost with respect to the air-to-water technology.

Table 6.7 - Costs data of the heat pumps [28]

Heat pump	CAPEX [€/kW]	Fixed O&M [€/kW/year]
Air-to-air	510	51
Air-to-water	750	15

For what concerns the variable costs for heating $c^m_{Heating}$, it is defined as the average cost necessary to produce 1 kWh of thermal energy for heating in area m, which is a function of the share of primary energy demand $PE_{m,i}$ by each source i, the conversion efficiency η_i and the specific cost c_i by source i:

$$c^m_{Heating}\left[\frac{€}{kWh_{th}}\right] = \frac{\sum_i PE_{m,i}[kWh] \cdot c_i \left[\frac{€}{kWh}\right] \cdot \frac{1}{\eta_i}\left[\frac{kWh}{kWh_{th}}\right]}{\sum_i PE_{m,i}[kWh]} \tag{6.9}$$

The costs for the other heating sources are provided as well. Notice that the sources "Electric" and "Heat pumps" are shown in Figure 6.48 only for completeness but are not used in the calculation of $c^m_{Heating}$, since only the demand which is not yet electrified is considered. Also notice that the efficiency value for the heat pumps is as in Table 6.6, which is only an average value that is different from the model's temperature-dependent $COP(T)$.

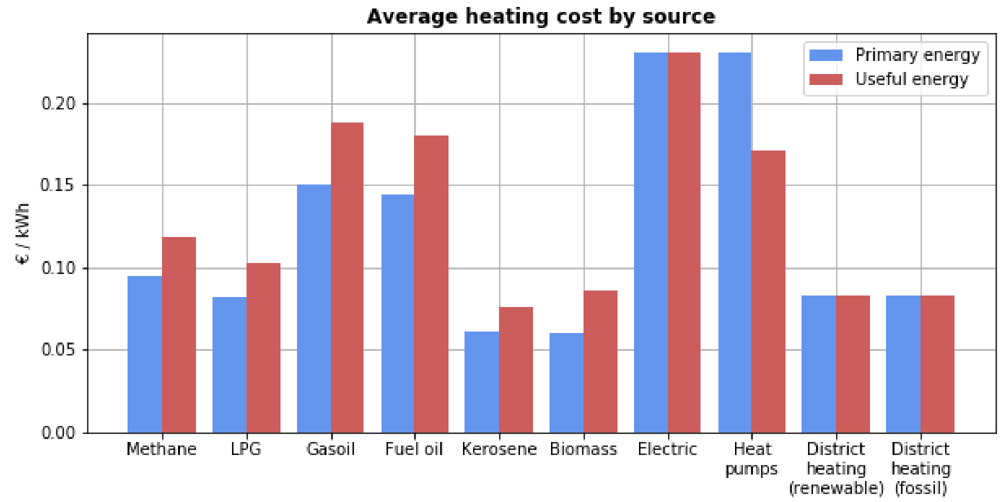


Figure 6.48 - Average cost by source

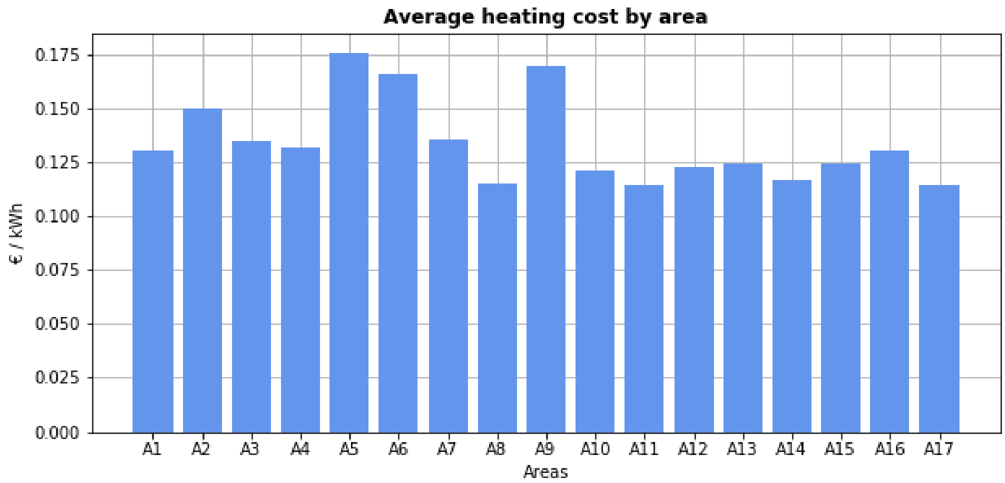


Figure 6.49 - Average cost of heating by area

The specific emissions by each source are also known. An approach based on the Life Cycle rather that the direct emissions is used. The last bar for each source in Figure 6.50 is calculated by dividing the LCAeq emission factor by the efficiency of each source (Table 6.6), obtaining the ton of equivalent CO_2 necessary to produce 1 kWh of useful thermal heating energy.

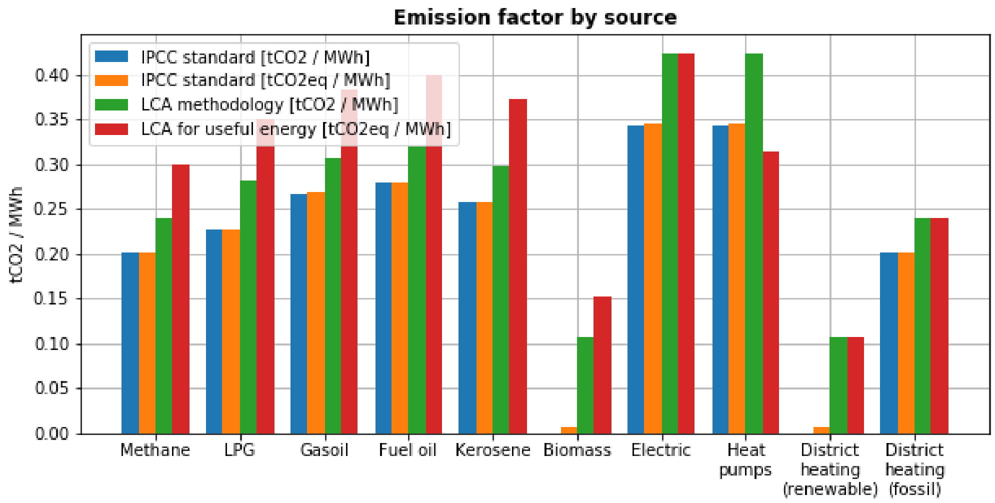


Figure 6.50 - Average emission factor by source

Table 6.8 - Average emission factor by source

Source	**IPCC [tCO_2/MWh]**	**IPCCeq [tCO_2eq/MWh]**	**LCAeq [tCO_2eq/MWh]**
Methane	0.202	0.202	0.240
LPG	0.227	0.227	0.281
Gasoil	0.267	0.268	0.306
Fuel oil	0.279	0.280	0.320
Kerosene	0.257	0.258	0.298
Biomass	0	0.007	0.106
Electric	0.343	0.344	0.424
Heat pumps	0.343	0.344	0.424
District heating (RES)	0	0.007	0.106
District heating (fossil)	0.202	0.202	0.240

The average CO_2 emission factor $e_{Heating}^{m,CO_2}$ of each area m are then obtained:

$$e^{m,CO_2}_{Heating}\left[\frac{t_{CO_2}}{kWh_{th}}\right] = \frac{\sum_i PE_{m,i}[kWh] \cdot e_i \left[\frac{t_{CO_2}}{kWh}\right] \cdot \frac{1}{\eta_i}\left[\frac{kWh}{kWh_{th}}\right]}{\sum_i PE_{m,i}[kWh]} \quad (6.10)$$

that corresponds to the average CO_2 emissions necessary to produce 1 kWh of useful thermal energy for heating in area m.

6.5 Storage

The storage costs are provided by the MicroGrids.py [62] model described in Chapter 5, while Liang [60] provides the emissions for the battery production.

Table 6.9 - Costs and emissions data of battery

Storage	**CAPEX [€/kWh]**	**Fixed O&M [% of investment cost]**	**LCAeq [tCO_2eq/MWh]**
Li-ion battery	500	2%	0.0127

In all scenarios, the maximum battery capacity is constant:

$$C_{Battery} \leq 100{,}000[kWh]$$

Chapter 7
Results and Discussion

This chapter shows the outcomes of the model. First of all, the impact of electrification on the fluxes, emissions and costs is analysed by considering different scenarios and objectives. Then, the three objective functions are singularly considered and the optimal solutions are obtained accordingly. Lastly, a multi-objective optimization is performed according to a global criterion and a weighted sum methodology, where the single objective functions are considered simultaneously by assigning them equal and varying weights, respectively.

It is important to highlight that in the multi-objective optimization with weighted sum methodology, according to the literature (Chapter 4.3), it should be up to the policy maker to select which weight to assign to each objective function depending on his or her preferences and needs. All the possible weights are in any case considered in order to obtain a trend of optimal solutions and to show the operation of the model.

In all scenarios the following rules hold: the objective refers to the quantity to minimize, i.e. the fluxes, cost or emissions; the maximum additional capacity refers to the constraints to the maximum additional generation to install that can be "unbounded", in case all sources have a 30 MW upper bound, or "bounded", if they are given upper bounds based on the already present capacity or roof surface for PV; the electrification can be either free, meaning that it can vary from 0 to 100%, or fixed at a certain value.

The model is built in Python 3.7 and solved using *Gurobi* as external solver in a Pyomo environment. The computational costs are all related to a processor *AMD Ryzen 3 2200U* with clock speed 2.50 GHz and 8 GB RAM (of which 6.91 usable).

7.1 Scenarios

All the analysed scenarios are listed in Table 7.1. In the impact of electrification analysis, the optimization is performed for each objective and for different input electrification levels, in order to observe how the output changes as the electrification increases. Also, the residual loads are given neither an upper nor a lower bound to allow the areas where high electrification levels could not be reached because of fluxes constraints to show a complete trend from 0 to 100% electrification. Of course, the residual profiles are then visualized and compared to the maximum loads in order to know which electrification level is truly feasible. For each case – where a case is identified by a couple objective + maximum additional capacity – the computational cost is about 3 hours (processor *AMD Ryzen 3 2200U* with clock speed 2.50 GHz and 8 GB RAM).

In the single objective analysis, the electrification is either a free variable, ranging from 0 to 100%, or an input parameter set at 0, 20 or 40%. The computational cost in this analysis is lower with respect to the previous one because there is no longer need to perform a calculation for all electrification levels, and is about 20 minutes (processor *AMD Ryzen 3 2200U* with clock speed 2.50 GHz and 8 GB RAM) for each case – where the case is identified by a set objective + maximum additional capacity + electrification.

Then, in the global criterion analysis the objective function is no longer either fluxes, emissions or costs, but all of them simultaneously. As for the previous studies, the cases are differentiated according to the maximum additional capacity and the electrification. The computational cost for each case is about 40 minutes (processor *AMD Ryzen 3 2200U* with clock speed 2.50 GHz and 8 GB RAM).

Lastly, in the weighted sum analysis the objective function is a weighted sum of the single objectives. The computational cost is way higher with respect to the other studies as an optimization needs to be performed for each set of weights in the multi-objective function. The time needed can be up to 15 hours in the unbounded potential and free electrification case or from 8 to 9 hours in other cases (processor *AMD Ryzen 3 2200U* with clock speed 2.50 GHz and 8 GB RAM).

In all analyses, the results refer to the "constant electricity cost" scenario. The "variable electricity cost" case is not shown as it presents very similar results with minor differences in a few areas.

Table 7.1 - List of analysed scenarios

Analysis	**Objective**	**Max additional capacity**	**Electrification**
Impact of electrification	Fluxes	Unbounded	Input parameter from 0 to 100%
	Costs		
	Emissions		
	Fluxes	Bounded	
	Costs		
	Emissions		
Single objective	Fluxes	Unbounded	Free variable
	Costs		
	Emissions		
	Fluxes	Bounded	
	Costs		

	Emissions		
	Fluxes		Input parameter 0%
	Costs		
	Emissions		
	Fluxes		Input parameter 20%
	Costs		
	Emissions		
	Fluxes		Input parameter 40%
	Costs		
	Emissions		
Global criterion	Global criterion method	Unbounded	Free variable
		Bounded	Input parameter 0%
			Input parameter 20%
			Input parameter 40%
Weighted sum	Weighted sum method	Unbounded	Free variable
		Bounded	Input parameter 0%
			Input parameter 20%
			Input parameter 40%

7.2 Impact of electrification

7.2.1 Fluxes objective

The following results are all preferentially related to area A12 *Aosta ponte pietra* for brevity. The trends for the storage capacity and the heat pumps mix are not illustrated as the first shows a constant trend with the maximum capacity installed for each electrification level, while in the second the air-to-air heat pumps, due to their higher efficiency, always cover the totality of the electrification.

Analysing the results, it is possible to notice that with increasing electrification the fluxes tend to increase too in opposition with the emissions for all areas. This is what was expected from the model, as electrifying the heating demand is one of the main ways to decrease emissions in spite of the higher stress on the grid. Area A12 *Aosta ponte pietra*, however, shows an initially increasing emissions trend up to 30% electrification (Figure 7.1) due to the fact that as the heating demand is more covered by heat pumps, the residual profile and the emissions related to the positive part of it tend to increase too. For area A12, therefore, it is not until 30% electrification that the positive outcome in terms of lower emissions by electrification is shown. For the costs, on the other hand, the results show an increasing trend for all areas. In fact, increasing the electrification requires investment and O&M costs for the HPs to be sustained and the residual profile to increase. But, depending on the area, the residual profile can present a summer inversion wide and negative enough to compensate for the additional costs thanks to the zonal price remuneration, as observed in areas A4 *Cretaz* and A5 *Entreves*. In fact, in the summer and autumn seasons the higher additional generation needed to satisfy the additional load by electrified heating in winter is not needed anymore by the heat pumps but it is injected in the grid and remunerated at the zonal price.

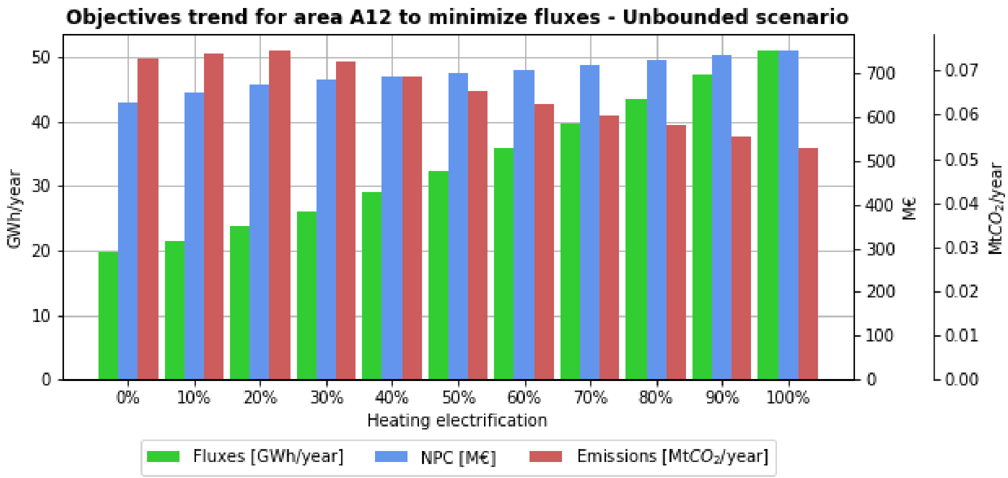


Figure 7.1 - Example of objectives trend with increasing electrification to minimize fluxes in unbounded potential scenario

The results with "bounded potential" generation capacity show a similar trend for all areas but very different absolute values (Figure 7.2). First, the total fluxes are about twice as the "unbounded potential" scenario, reflecting a source availability which is less fluxes-friendly. The costs are observed to slightly increase too. Only area A5 *Entreves* maintains its decreasing trend for the costs objective, reflecting the different source availability for area A4 *Cretaz* which copes with the electrified heating demand in a worse way than previously.

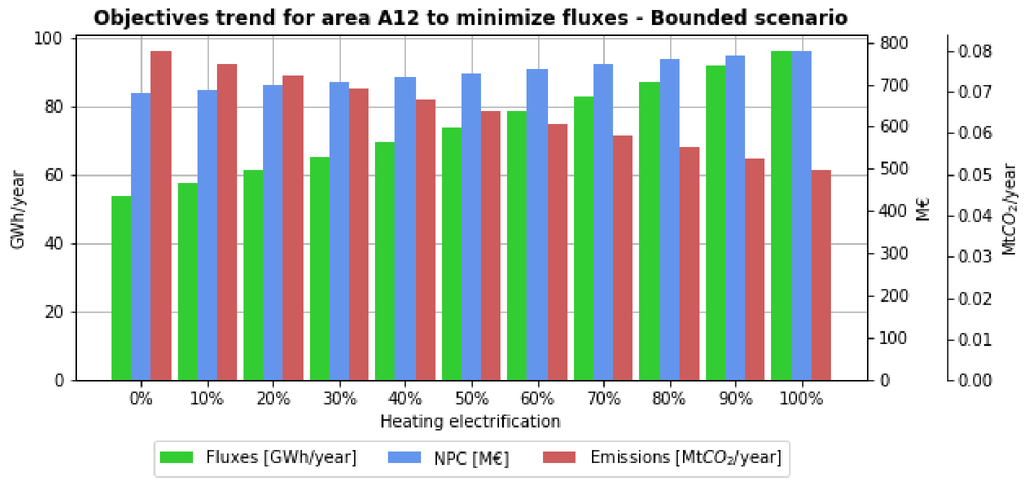


Figure 7.2 - Example of objectives trend with increasing electrification to minimize fluxes in bounded potential scenario

The additional generation capacity for area A12 *Aosta ponte pietra* shows a great – and increasing with electrification – importance of the bio source, together with PV, hydro and wind (Figure 7.3). Since the objective is the minimization of the fluxes through the transformation primary substation, the bio source is selected due to its much more constant trend with respect to other sources, together with the hydro C source. It is interesting to notice that the PV, having a nonnull production only during daytime when the heating demand is lower, loses importance with increasing electrification in favour of the bio and wind sources. This is also the case for the hydro C source that has a little higher production in summer when the heating demand is lower. On the other hand, the bio source produces less in summer, making it the perfect choice to cope with the overall electric – comprising electrified heating – demand. All other areas install CHP and bio especially since both have higher production in winter when the heating demand is higher too.

With "bounded potential", having almost null bio availability in area A12 *Aosta ponte pietra*, the choice falls on the PV and CHP (Figure 7.4). The maximum PV capacity in Area A12 is estimated to be about 100 MW, so the optimal PV capacity at 100% electrification corresponds to about 35% of the overall potential. For CHP and hydro B, on the other hand, the optimization selects the totality of the potential to be installed for all electrifications. For the other areas, instead, the output depends on the actual availability of each source. In general, the installed capacity will tend to be as close as possible to the "ideal" unbounded results but, in absence of such availabilities, the additional capacity will prefer those sources that have higher production in winter or the lowest difference between the productions in winter and summer, i.e. CHP, bio, wind, hydro C and hydro B in this order. When these sources are not available, PV is chosen or, as for the cases of areas A14 *Rhins* and A17 *Zuino*, no additional capacity is installed.

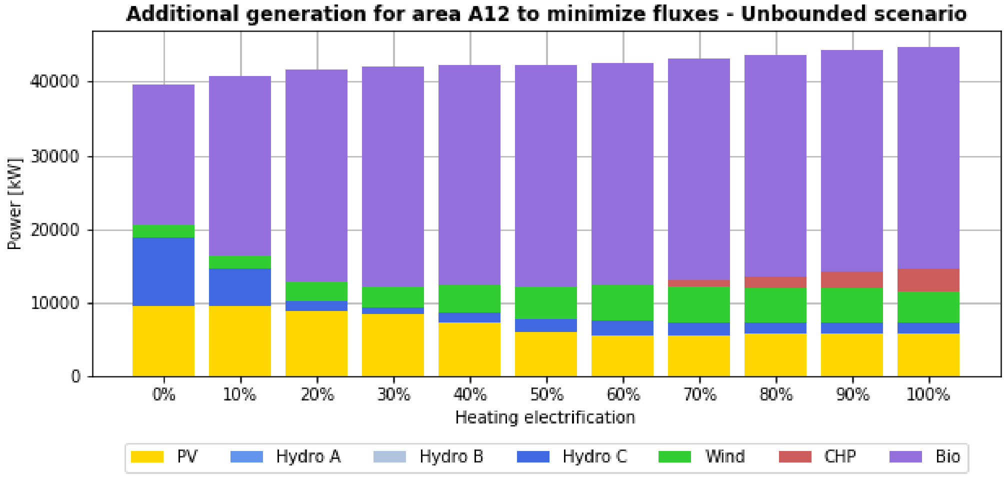


Figure 7.3 - Example of additional generation with increasing electrification to minimize fluxes in unbounded potential scenario

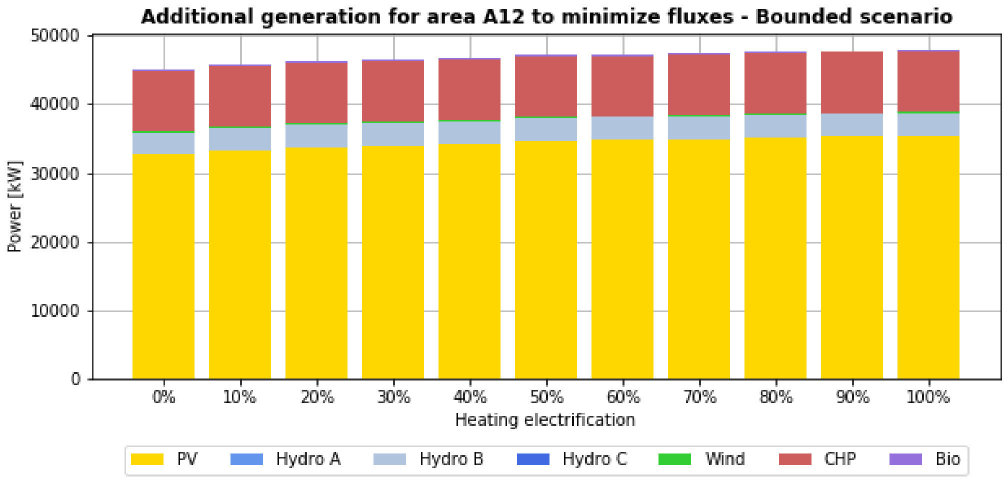


Figure 7.4 - Example of additional generation with increasing electrification to minimize fluxes in bounded potential scenario

Lastly, the residual profiles with respect to the initial one are also shown in Figure 7.5. It can be noticed that the difference among the profiles with different electrification, despite being accentuated in winter, are almost null in summer. Also, if a higher electrification implies a higher residual profile in winter, in summer there exists an inversion that sees the higher electrification curve be “more negative” than the others. This is caused by the fact that the additional generation installed to cover the electrified heating demand in winter has no longer to satisfy the null or almost null heating demand in summer, therefore contributing to increase the power exiting the area and entering the grid.

With “bounded potential” availability, the fluxes differences in area A12 *Aosta ponte pietra* are much wider with a more accentuated inversion in summer, thanks to the higher PV capacity installed (Figure 7.6).

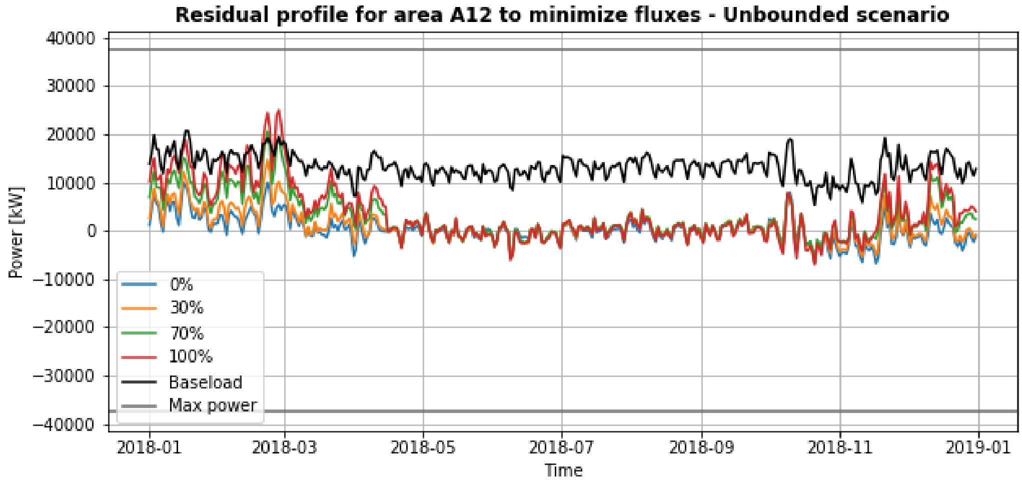


Figure 7.5 - Example of residual profiles with increasing electrification to minimize fluxes in unbounded potential scenario

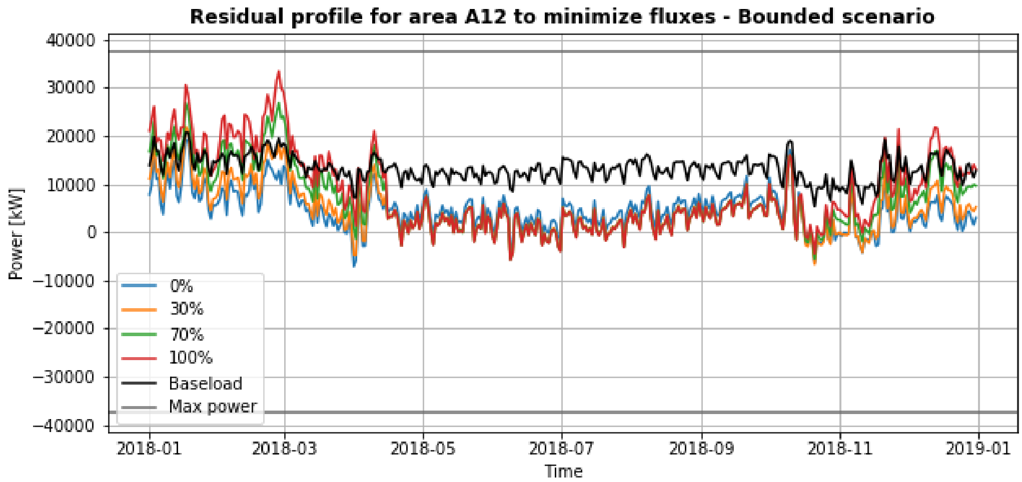


Figure 7.6 - Example of residual profiles with increasing electrification to minimize fluxes in bounded potential scenario

7.2.2 Emissions objective

With the objective of minimizing the emissions by the consumption of energy, with increasing electrification the emissions tend to decrease (Figure 7.7). This is an expected output, as the average emission factor of the heating demand in each area is generally higher than the electricity one accounting for the heat pump COP. The total fluxes increase for all areas, whereas the costs increase too except for areas A14 *Rhins* and A16 *Villeneuve*.

The objectives trend in the “bounded scenario” is similar to the first case (Figure 7.8). The fluxes are observed to almost double and the costs and emissions to increase too.

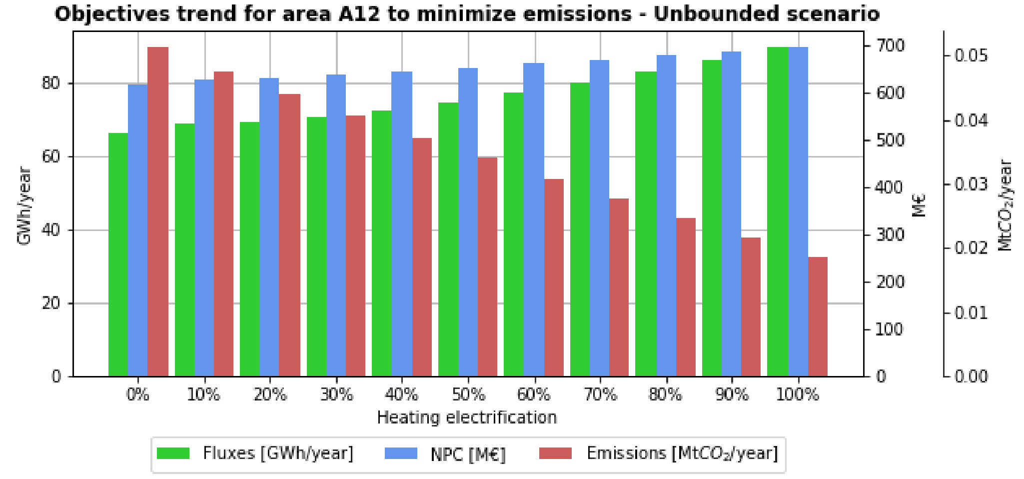


Figure 7.7 - Example of objectives trend with increasing electrification to minimize emissions in unbounded potential scenario

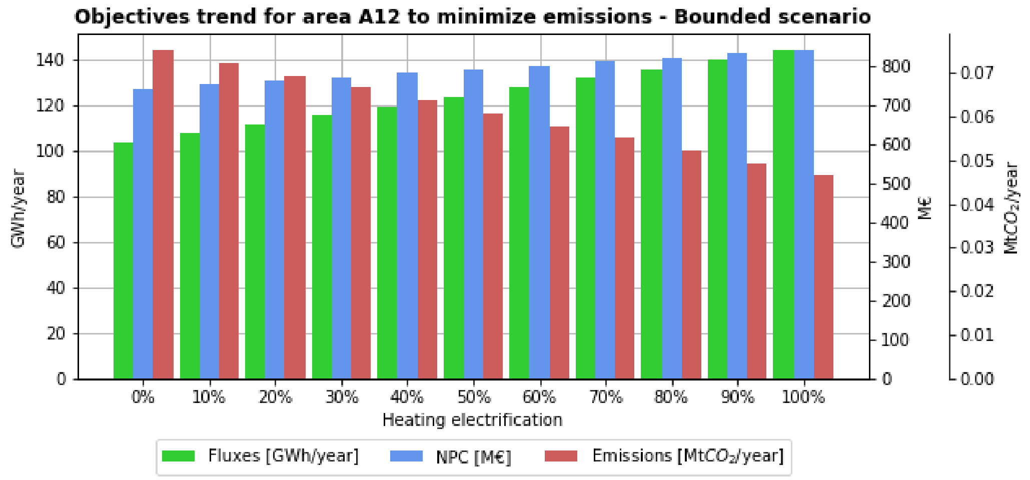


Figure 7.8 - Example of objectives trend with increasing electrification to minimize emissions in bounded potential scenario

The additional generation capacity with the objective of minimizing the emissions shows an equal importance given to the hydro of all types, PV and wind in the "unbounded" scenario, that correspond to the sources with the lowest emission factors (Figure 7.9). The emissions minimization also sees the highest additional capacity installed among all the objectives, since the purpose of the optimization is to decrease the positive power transit as much as possible. Many areas, in fact, reach the full "unbounded" availability equal to 30 MW for each source, among which also area A12 *Aosta ponte pietra* that reaches the saturation at 10% electrification. Other areas present a smoother trend where the maximum availability is not reached or is reached at higher electrification levels, reflecting a way lower initial load with respect to area A12.

With “bounded potential”, the generation capacity sees a constant and important presence of PV and hydro, based on the estimated “bounded” availability (Figure 7.10). For all electrifications, the maximum availabilities of PV and hydro B are installed in area A12 *Aosta ponte pietra* and in most other areas. For CHP and bio, instead, being associated to relatively high emission factors, the optimization never selects them to be installed when minimizing the emissions.

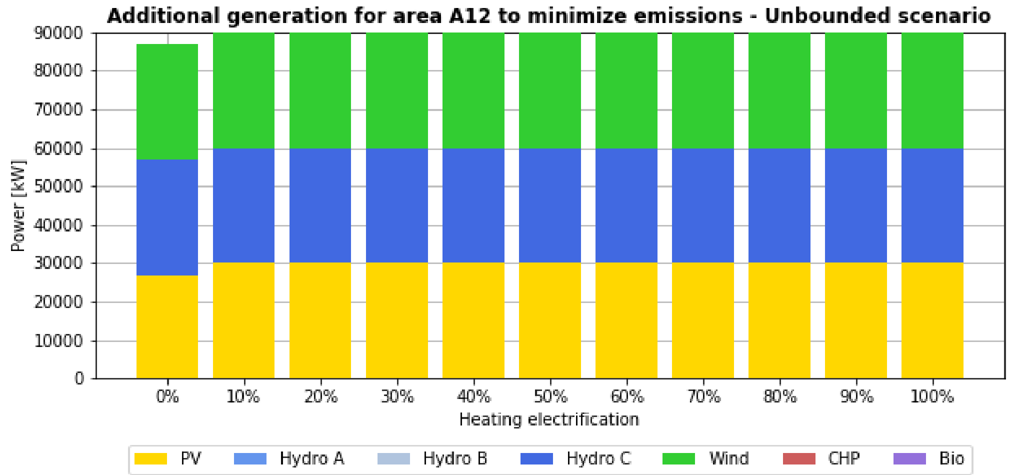


Figure 7.9 - Example of additional generation with increasing electrification to minimize emissions in unbounded potential scenario

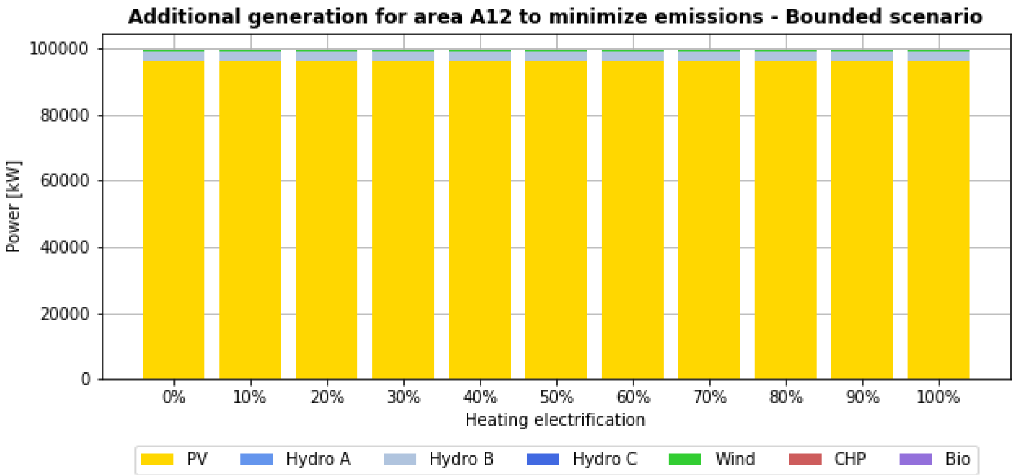


Figure 7.10 - Example of additional generation with increasing electrification to minimize emissions in bounded potential scenario

Lastly, the residual profiles are observed to increase towards the positive direction with increasing electrification in winter (Figure 7.11) with the typical inversion in summer. This, however, is not the case for all areas, as some of them – i.e. areas A10 *Pont Saint Martin* and A16 *Villeneuve* in the “bounded potential” scenario – are observed to actually translate the profiles towards more negative values with increasing electrification all along the year, even in the cold season. In fact, as an emission factor is assigned to the electricity coming from the grid, the optimization prefers to install more generation capacity rather than increase the emissions by satisfying the heating demand with the grid electricity. Installing more generation, consequently, translates into more negative profiles, not only in summer but, for these areas, even in winter. In the “bounded potential” scenario all profiles are much closer to each other and, for area A12 *Aosta ponte pietra*, return to show the summer inversion with respect to winter (Figure 7.12).

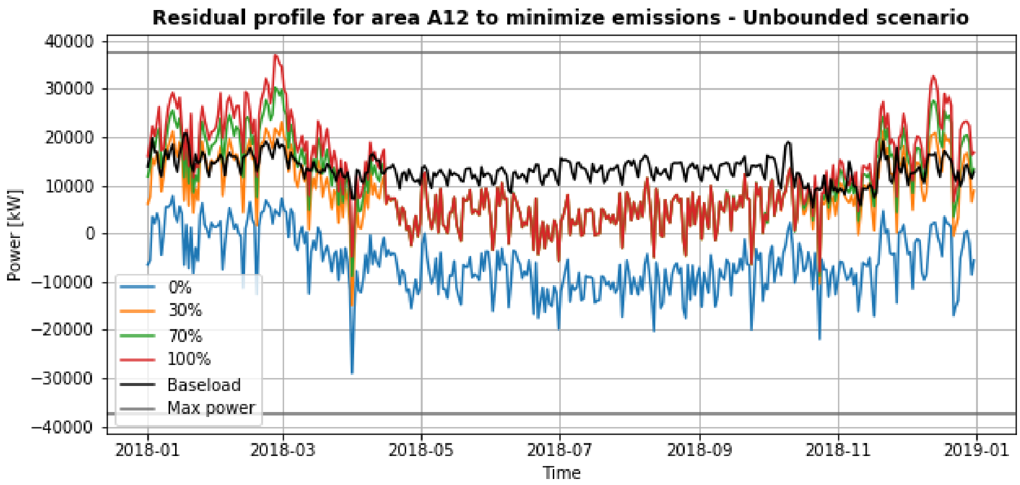


Figure 7.11 - Example of residual profiles with increasing electrification to minimize emissions in unbounded potential scenario

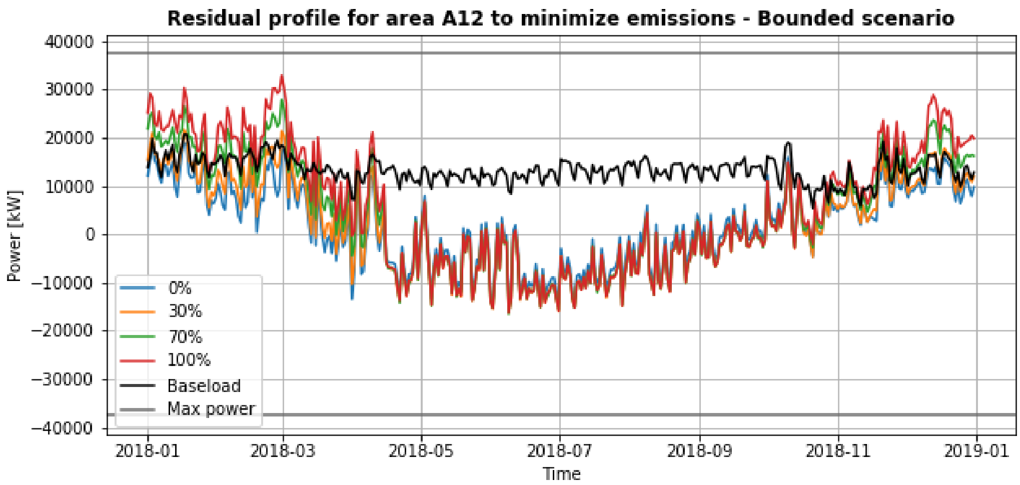


Figure 7.12 - Example of residual profiles with increasing electrification to minimize emissions in bounded potential scenario

7.2.3 Costs objective

Differently from the previous ones, the costs objective show always null storage capacity for each electrification level, together with a nonnull presence of air-to-water heat pumps to cover the electrified heating demand even if they are upper bounded by the fraction of recent-construction households in the buildings stock. As expected, for all areas the total fluxes have much higher values with respect to the previous objectives, whereas the costs and emissions are observed to have averagely lower values. More interestingly, the trends for each objective is different with respect to the previous cases. First, the total fluxes are observed to increase with increasing electrification for all areas (Figure 7.13) except for A16 *Villeneuve* in the "unbounded" scenario, meaning that the additional electrical load for heating helps to increase the negative profile towards the zero. For the costs objective, all areas have an increasing trend with increasing electrification except for A5 *Entreves*, A6 *Gressoney*, A8 *Nus*, A14 *Rhins* and A16 *Villeneuve*, meaning that for these areas electrifying heating allows to save costs. Area A16 *Villeneuve* is even observed to have negative overall costs, meaning that the profile is so negative that the economic gain by selling electricity to the grid overcomes the overall costs in the 20 years period. Of course, this is not verisimilar and is due to the absence of lower bounds to the power transit.

In the "bounded potential" scenario, all areas have the same trend as in the "unbounded" case except for area A6 *Gressoney*, A8 *Nus*, A14 *Rhins* and A16 *Villeneuve*, that change direction and show an increasing costs trend. All values are higher with respect to the previous case (Figure 7.14).

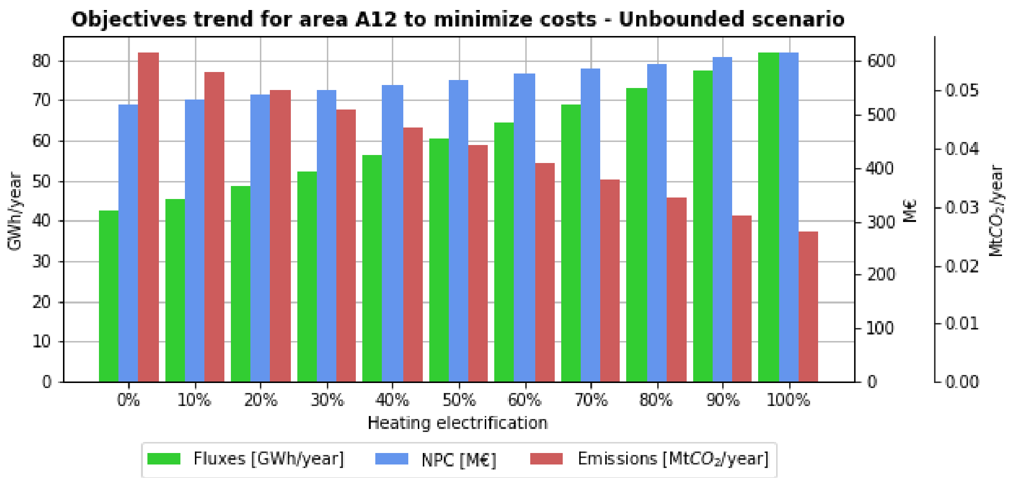


Figure 7.13 - Example of objectives trend with increasing electrification to minimize costs in unbounded potential scenario

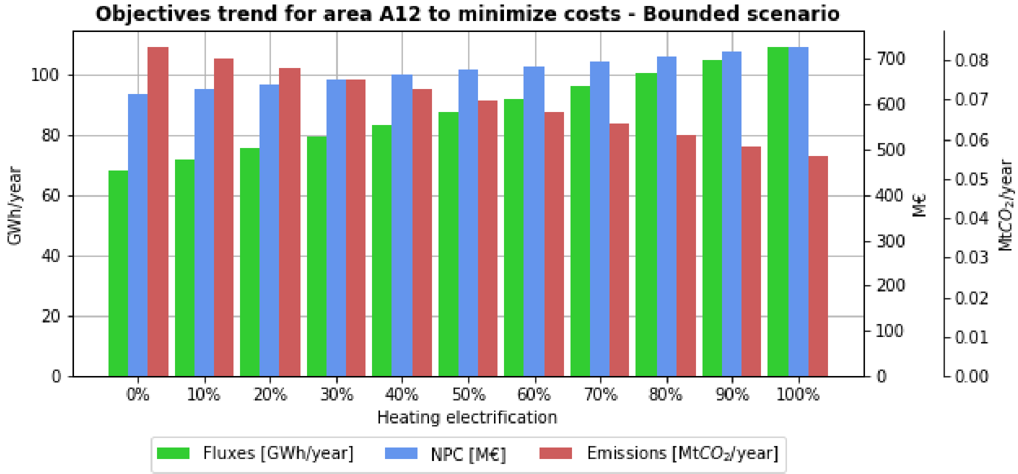


Figure 7.14 - Example of objectives trend with increasing electrification to minimize costs in bounded potential scenario

The additional "unbounded" generation is especially made of all types of hydro and wind together with CHP for areas A2 *Ayas*, A4 *Cretaz* and A7 *Morgex* and bio for areas A2 and A4. In area A12 *Aosta ponte pietra* the maximum availability of hydro in installed (Figure 7.15).

The generation mix in the "bounded potential" scenario, on the other hand, sees that most of the additional capacity is represented by wind and bio in almost all areas, all hydro sources to their full potential, PV in areas A1 *Aosta ovest*, A6 *Gressoney*, A11 *Pont Saint Martin 2* and A12 *Aosta ponte pietra* (Figure 7.16).

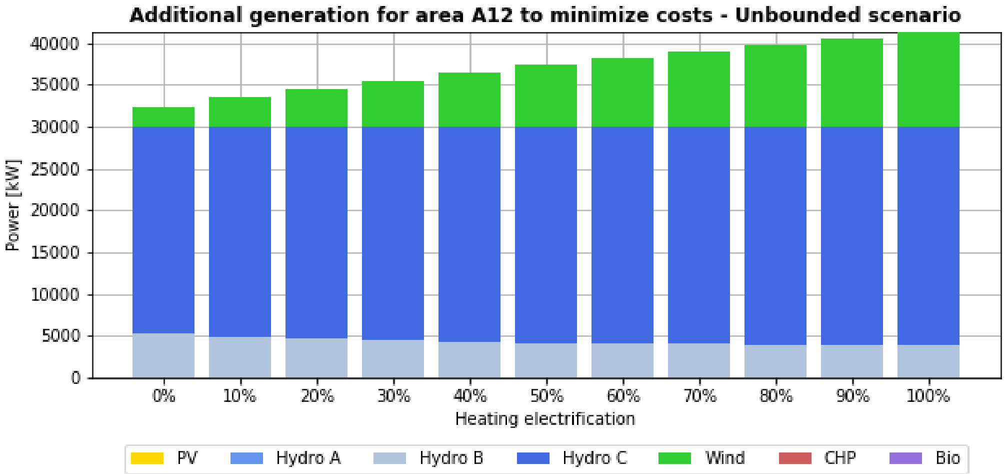


Figure 7.15 - Example of additional generation with increasing electrification to minimize costs in unbounded potential scenario

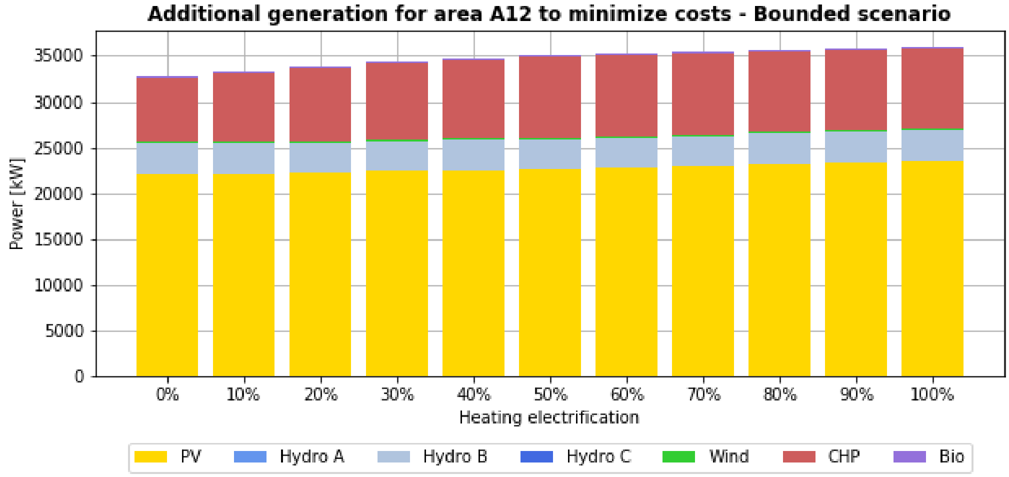


Figure 7.16 - Example of additional generation with increasing electrification to minimize costs in bounded potential scenario

The residual profiles show the characteristic inversion between winter and summer for most areas (Figure 7.17), whereas area A3 *Covalou* shows a particular trend where the residual profiles shift towards the negative with increasing electrification during both summer and winter. This is due to the fact that, as previously stated, as the electrification level increases the residual profile will tend to increase to account for the additional electrified heating load and the costs will tend to increase too. For this reason, the optimization is such that more generation capacity is installed to make the profile shift towards the negative and, by doing so, add an additional remuneration rather than an additional cost.

With "bounded potential" the profiles get closer to each other (Figure 7.18).

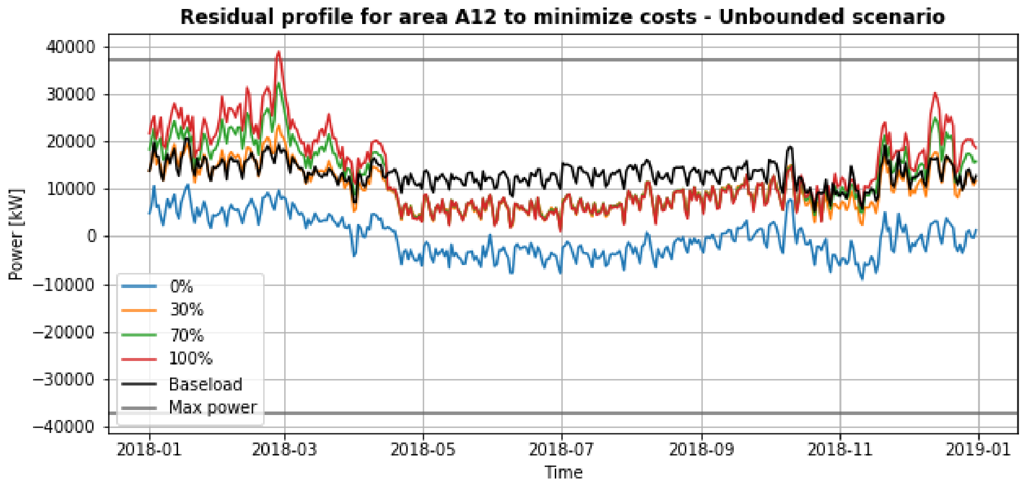


Figure 7.17 - Example of residual profiles with increasing electrification to minimize costs in unbounded potential scenario

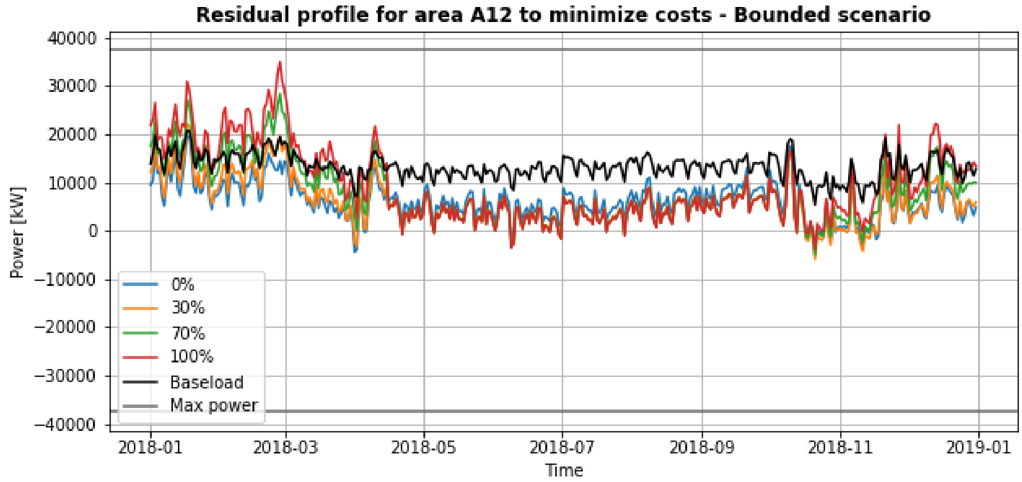


Figure 7.18 - Example of residual profiles with increasing electrification to minimize costs in bounded potential scenario

7.3 Single objectives

7.3.1 Fluxes objective

By performing a single objective optimization for each area with the purpose of minimizing the fluxes through the transformation primary substation, it is observed that, as for the electrification impact analysis, great importance is given to both the bio and CHP technologies in all areas in the "unbounded potential" scenario (Figure 7.19). Areas A14 *Rhins* and A16 *Villeneuve* present a null additional generation, meaning that each additional capacity would increase the fluxes. The only area for which other sources other than bio and CHP would have to be significantly installed is area A12 *Aosta ponte pietra*, where 10 MW of PV plants, about 18 MW of hydro C and 4 MW of wind are selected in the optimization. The results related to the heat pumps mix and the storage capacity are not reported, as the first show an always null trend – it is better not to electrify to minimize the fluxes – and the second show an always maximum trend.

By considering the "bounded potential" – either free, 0%, 20% or 40% electrification as the results are similar – scenario, expectedly the optimization selects more PV since it is the most available source, as shown in Figure 7.20. It is interesting to notice that, for some areas, the overall installed capacity is higher in this scenario with respect to the "unbounded potential" one, while for others the overall capacity decrease to almost zero. No area reaches the full availability by any source, except for area A12 *Aosta ponte pietra* that installs the maximum CHP and hydro B.

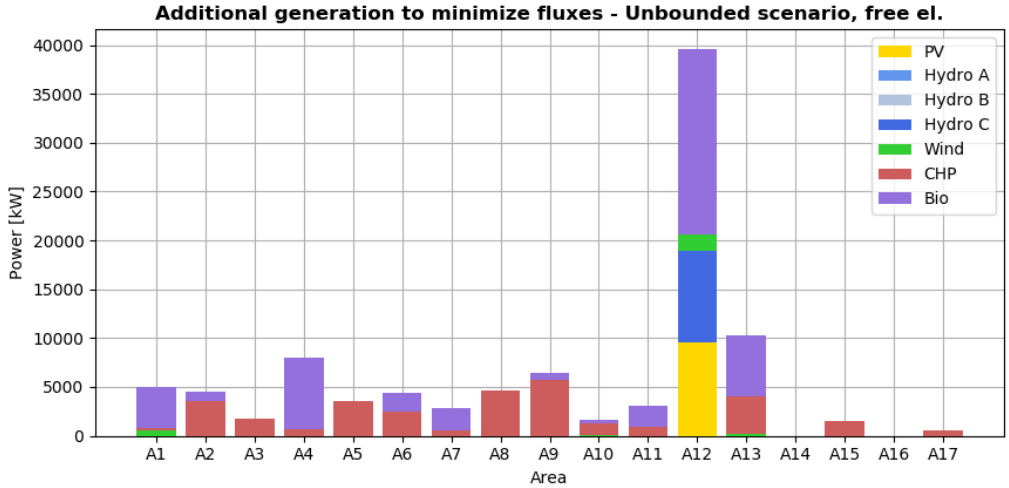


Figure 7.19 - Additional generation by area and by source to minimize fluxes in unbounded potential and free electrification scenario

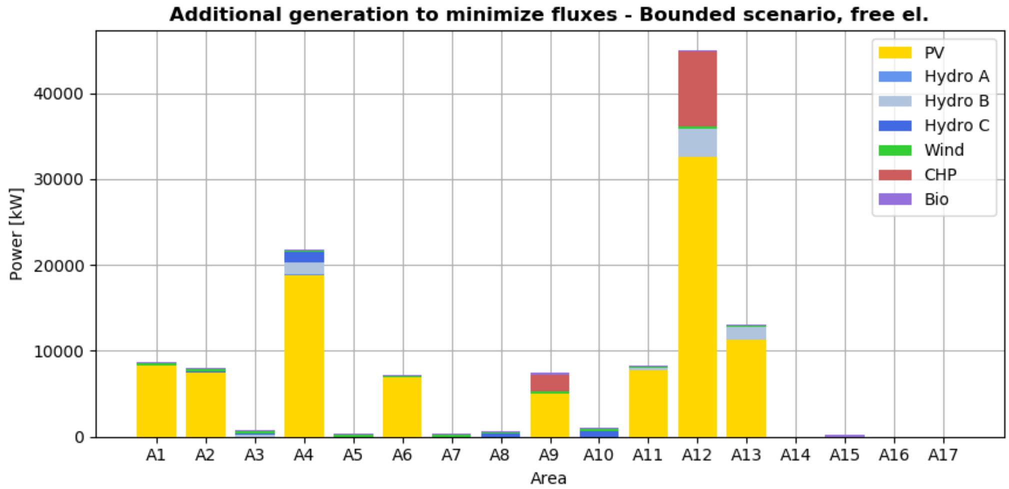


Figure 7.20 - Additional generation by area and by source to minimize fluxes in bounded potential and free electrification scenario

The minimum total fluxes that can be reached by singularly minimizing them for each area are reported in Figure 7.21 and Figure 7.22, for the "unbounded" and "bounded potential" scenarios, respectively. Notice that the areas that show the highest values, namely area A5 *Entreves*, A14 *Rhins*, A15 *Verres* and A16 *Villeneuve*, are the ones that already had very negative load profiles due to the high summer production by the hydroelectric plants.

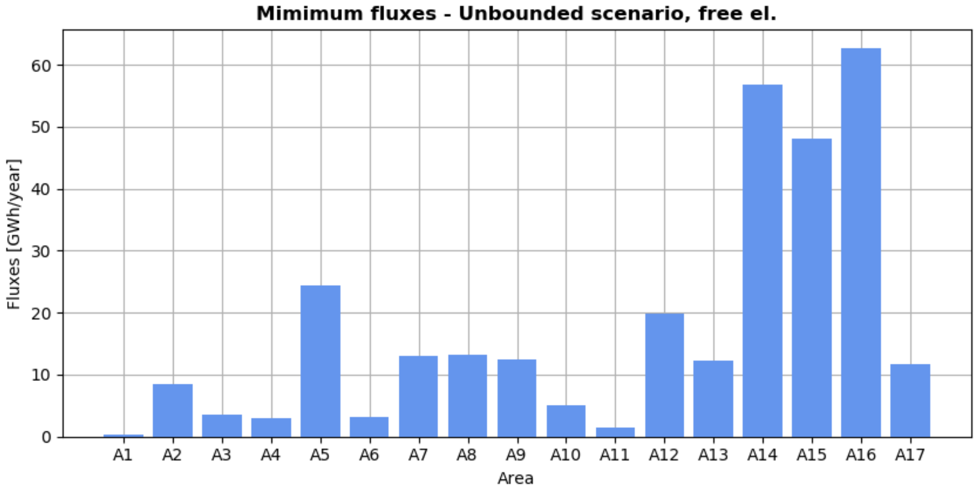


Figure 7.21 - Minimum fluxes by area with fluxes minimization in unbounded potential and free electrification scenario

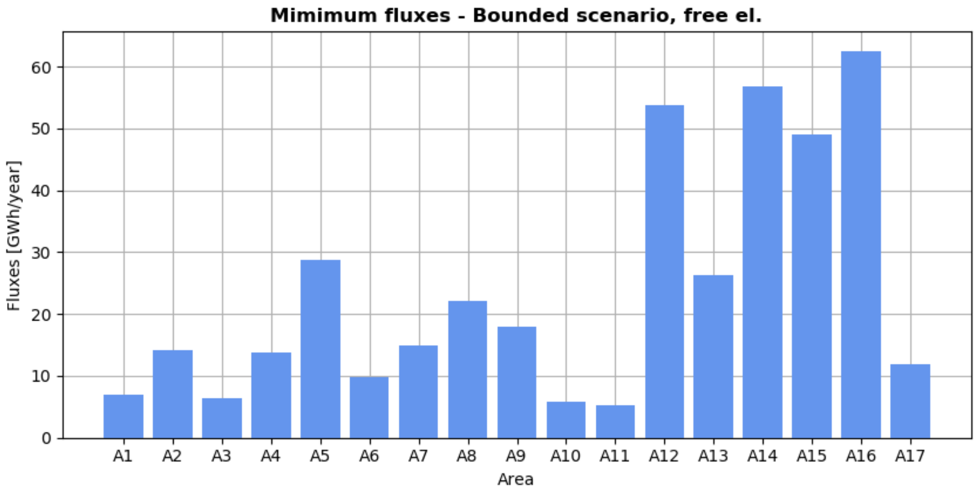


Figure 7.22 - Minimum fluxes by area with fluxes minimization in bounded potential and free electrification scenario

Incoming fluxes objective

An additional study regarding the minimization of the incoming fluxes for each area is performed. This analysis is useful to understand the minimum additional generation capacity that would be needed in each area to have an always negative load, i.e. a profile which is always exiting the area and entering the grid. Ideally, by installing that capacity the area should be able to, first, be autonomous and independent from the grid and resilient and self-sustaining in cases of national blackouts or power shortages and, second, help the grid to manage the same shortages by injecting power. In this analysis, therefore, the objective function is modified with respect to the fluxes objective such that the sum of only the positive residual profile, i.e. $Z^{+}(t)$, is taken into account by considering two scenarios: the first in which the lower bound of the ratio between $\sum_t Z^{+}(t)$ and $Fluxes_{Tot}$ is 0% and the second in which it is 5%. In both scenarios, the power limitation of the primary substation is taken into account and the storage capacity is set to be null. Moreover, no upper bound is considered for the additional generation capacity.

The results are shown in the following figures. For the 0% scenario (Figure 7.23), the installed capacity varies among the areas but the bio source seems to be more frequent in all of them, as it is the source that nullify the most the positive load. With 40% electrification, expectedly the generation capacity to install is higher and the bio source gains more importance since its characteristic profile better copes with the additional heating demand profile (Figure 7.26). In the 5% scenario the results show that the installed capacity decreases by almost half, demonstrating that the optimal additional generation is sensible to the magnitude by which the incoming profile is forced to decrease (Figure 7.27 and Figure 7.28).

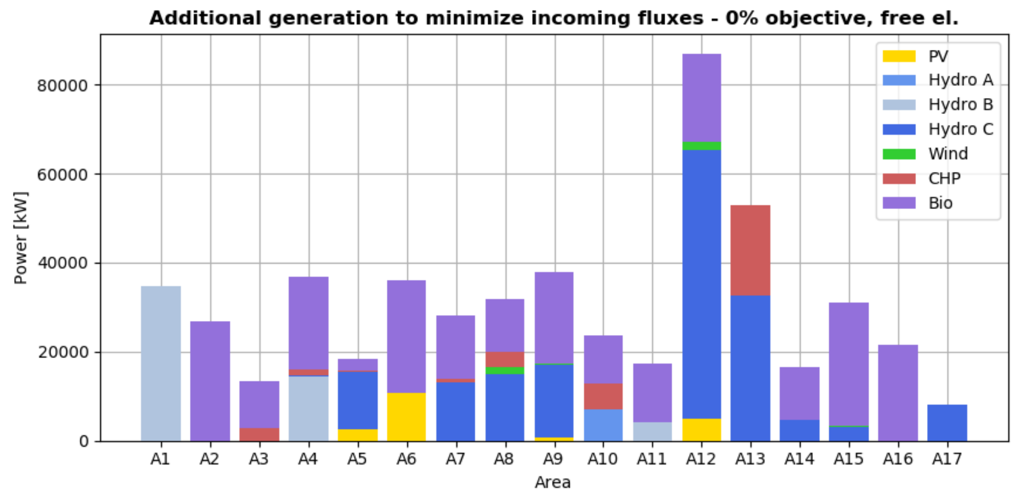


Figure 7.23 - Additional generation by area and by source to minimize incoming fluxes with 0% objective and free electrification

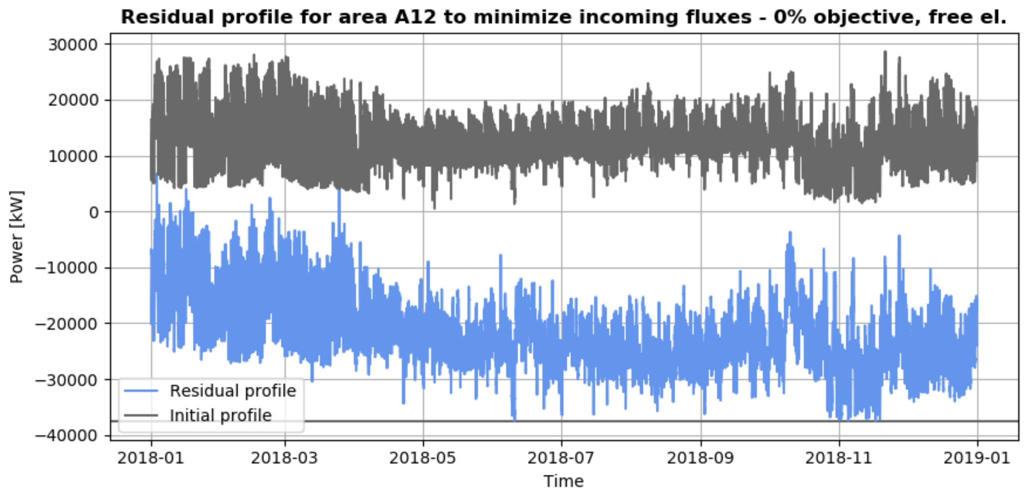


Figure 7.24 a) - Example of residual profile to minimize incoming fluxes with 0% objective and free electrification (15 minutes resolution) *

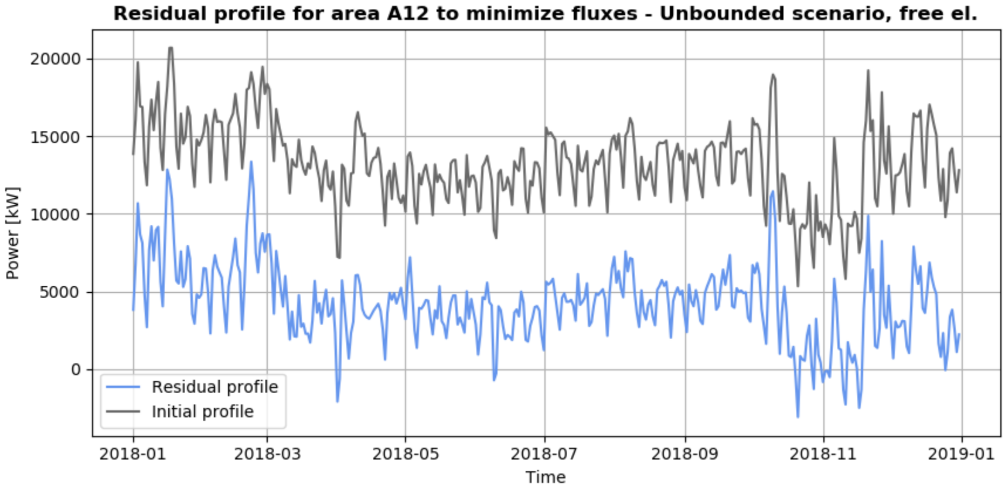


Figure 7.25 b) - Example of residual profile to minimize overall fluxes in unbounded potential and free electrification scenario (daily average) *

* Notice that the incoming fluxes minimization is performed without constraints to the additional capacity, whereas in the overall fluxes minimization the additional capacity is given an upper bound.

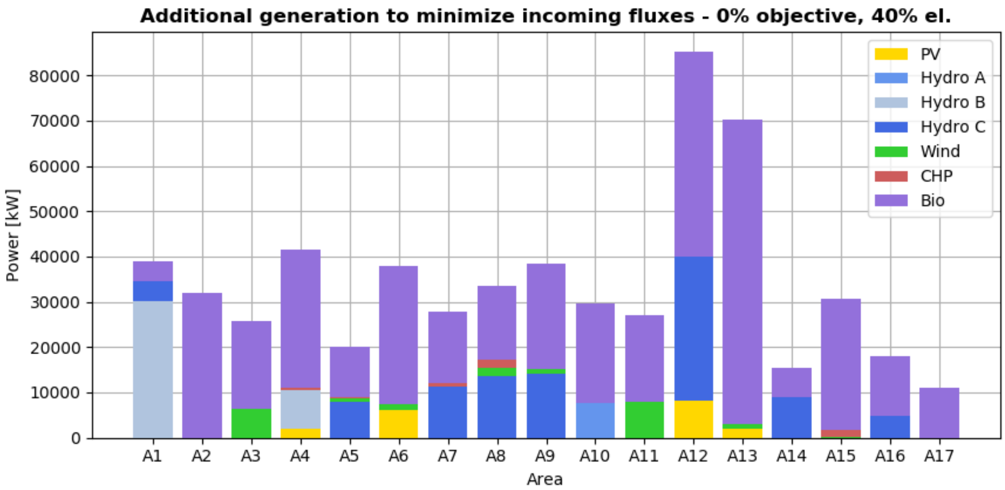


Figure 7.26 - Additional generation by area to minimize incoming fluxes with 0% objective and 40% electrification

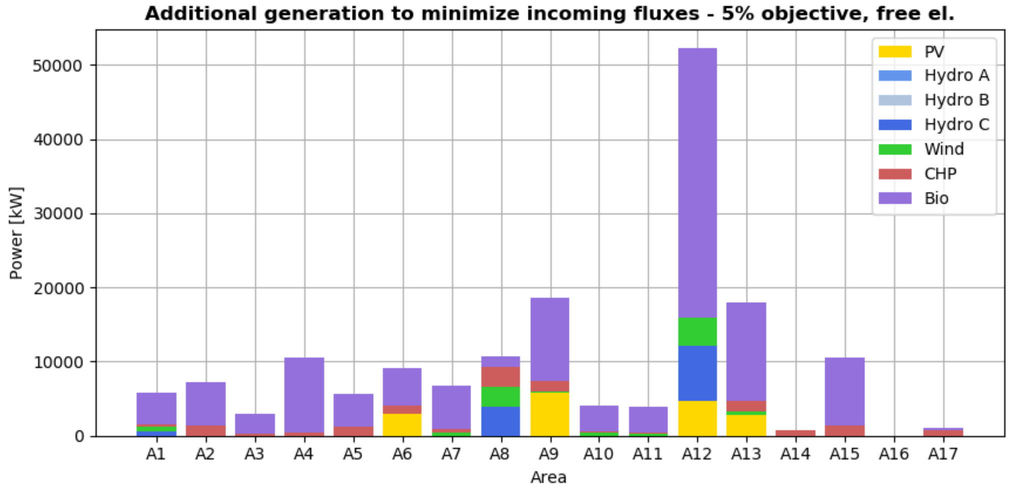


Figure 7.27 - Additional generation by source to minimize incoming fluxes with 5% objective and free electrification

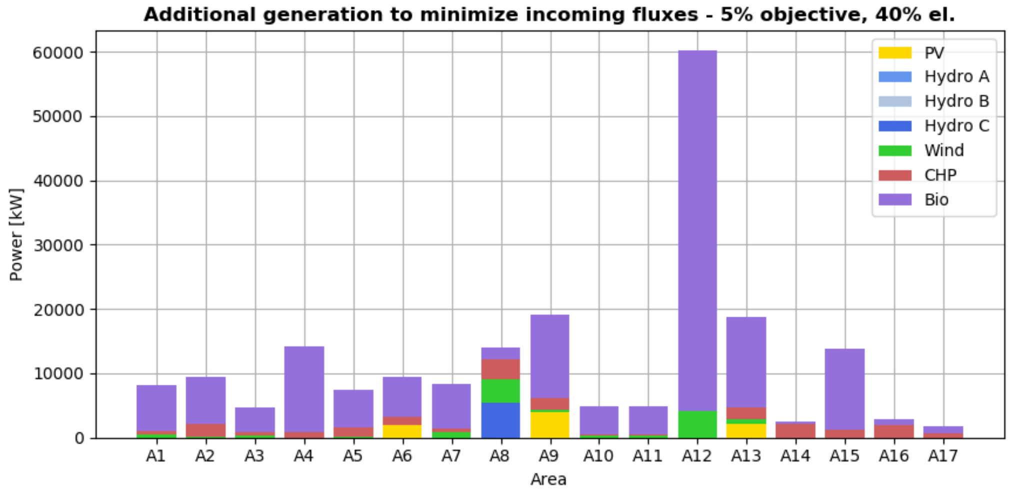


Figure 7.28 - Additional generation by source to minimize incoming fluxes with 5% objective and 40% electrification

7.3.2 Emissions objective

When the objective is the minimization of the emissions, hydro B and C play a key role together with wind and PV, as shown in Figure 7.29. Hydro C, in particular, reaches its upper bound of 30 MW in the "unbounded potential" scenario in most areas. This is an interesting result as, being that an emission factor is assigned to the electricity coming from the grid, the optimization will prefer to install the sources that not only present the lowest specific emission, but that are also more able to minimize the positive part of the load, i.e. the one associated to the emissions from the grid electricity. For all areas, obviously, increasing the electrification helps decreasing the emissions and, consequently, the maximum electrification will be reached in all of them. However, for area A12 *Aosta ponte pietra* a maximum electrification cannot be reached due to the constraints to the load: increasing its value up to 100% would not respect the transformers nominal powers and a value of almost 60% is reached instead. The results related to the storage capacity, on the other hand, show an always maximum value for all areas. Notice that the results are different with respect to the impact of electrification analysis as the limitation related to the maximum fluxes are now taken into account.

By considering a "bounded potential" availability in Figure 7.30, the optimization sees more installed PV in all areas together with hydro of all types. The areas with the lowest bounded potential install the maximum capacity, while the others, such as area A12 *Aosta ponte pietra*, reach a little more than half of the maximum PV availability. For what concerns the heat pumps mix, area A12 sees an even lower electrification equal to about 50%, due to the fact that the "bounded potential" scenario availability is not able to satisfy the primary substation limitations without decreasing the overall electrification by more than 10%.

The results for 0%, 20% and 40% electrification are very similar to the free electrification scenario, with only a little decrease in the overall installed capacity (Figure 7.31).

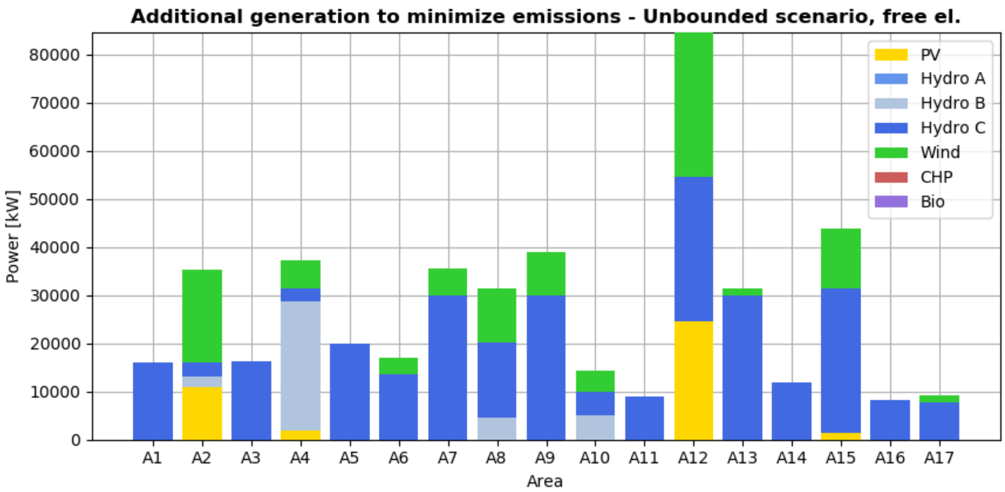


Figure 7.29 - Additional generation by area and by source to minimize emissions in unbounded potential and free electrification scenario

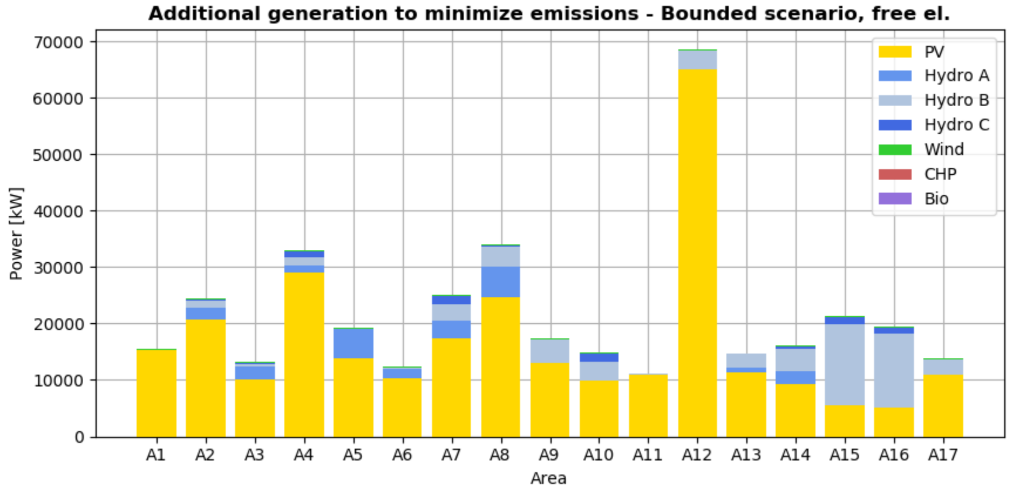


Figure 7.30 - Additional generation by area and by source to minimize emissions in bounded potential and free electrification scenario

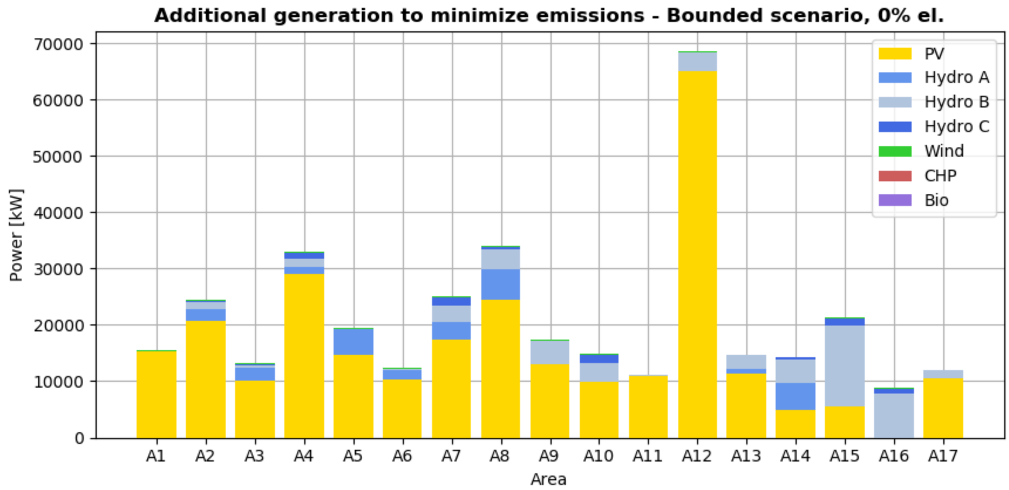


Figure 7.31 - Additional generation by area and by source to minimize emissions in bounded potential and 0% electrification scenario

Lastly, the minimum emissions from the consumption of energy are shown in the following figures, where area A12 *Aosta ponte pietra* is observed to present the highest minimum emissions (Figure 7.32). The minimum emissions in the "bounded" scenario with free (Figure 7.33) and 0% (Figure 7.34) electrifications are about ten times higher than the unbounded scenario for all areas.

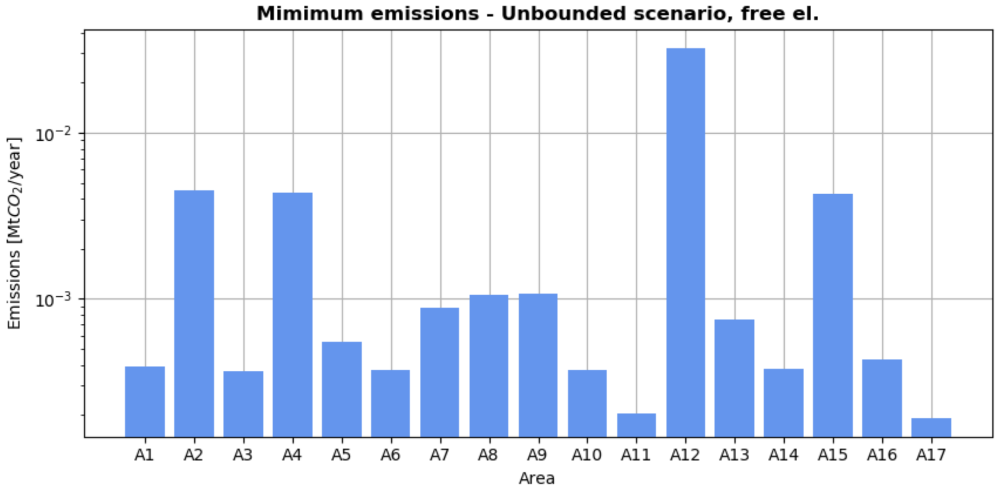


Figure 7.32 - Minimum emissions by area with emissions minimization in unbounded potential and free electrification scenario

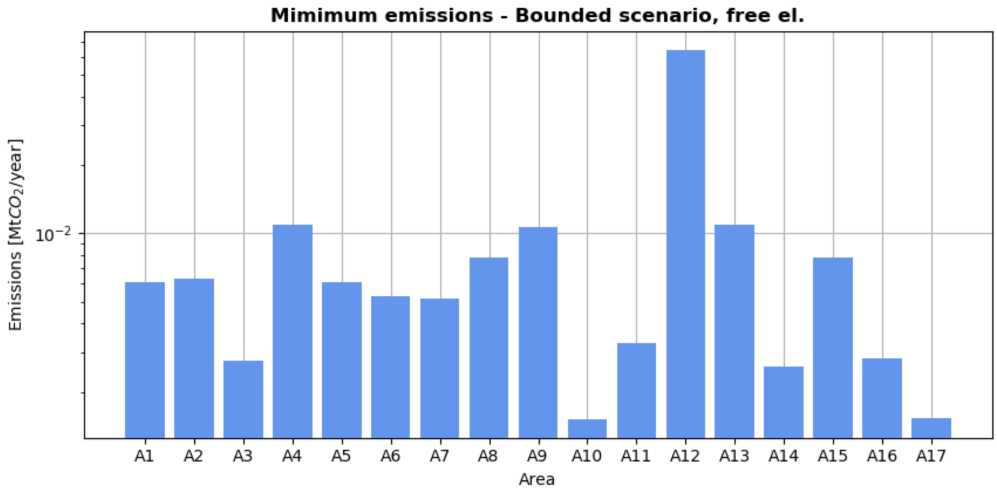


Figure 7.33 - Minimum emissions by area with emissions minimization in bounded potential and free electrification scenario

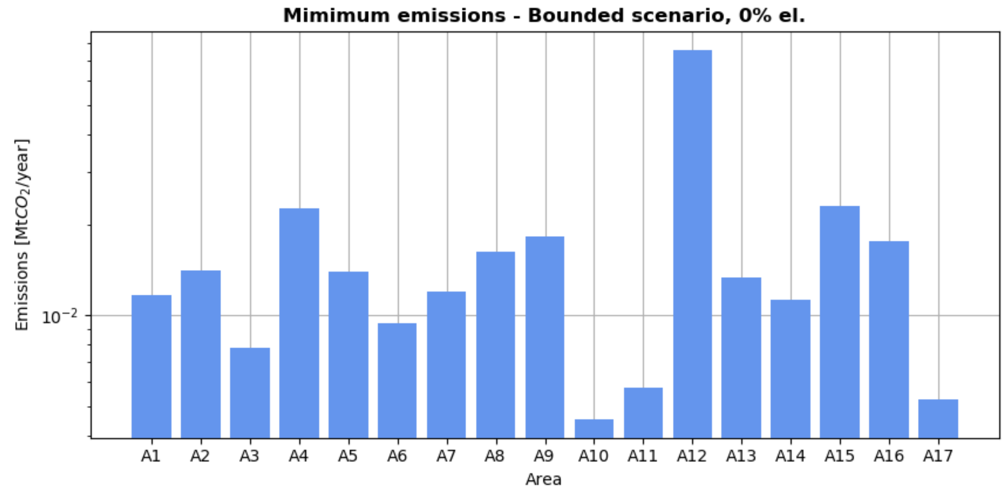


Figure 7.34 - Minimum emissions by area with emissions minimization in bounded potential and 0% electrification scenario

7.3.3 Costs objective

The costs minimization sees an additional generation capacity made of hydro A, B and C in all areas with a few bio, wind and CHP (Figure 7.35). The overall additional generation is lower than the emissions minimization scenario, as here also the operation and investment costs are considered. In no area the full sources availability is reached except for area A12 *Aosta ponte pietra*. The results shown refer to the scenario with constant electricity cost. The variable cost scenario was also analysed but was observed to be very similar to the first, with the only significant difference represented by the absence of bio in area A4 *Cretaz*.

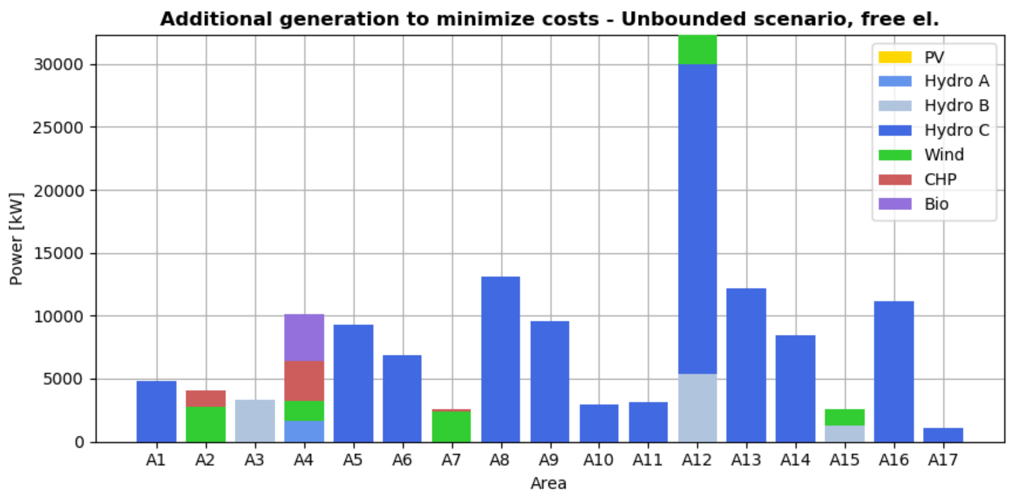


Figure 7.35 - Additional generation by area and by source to minimize costs in unbounded potential and free electrification scenario

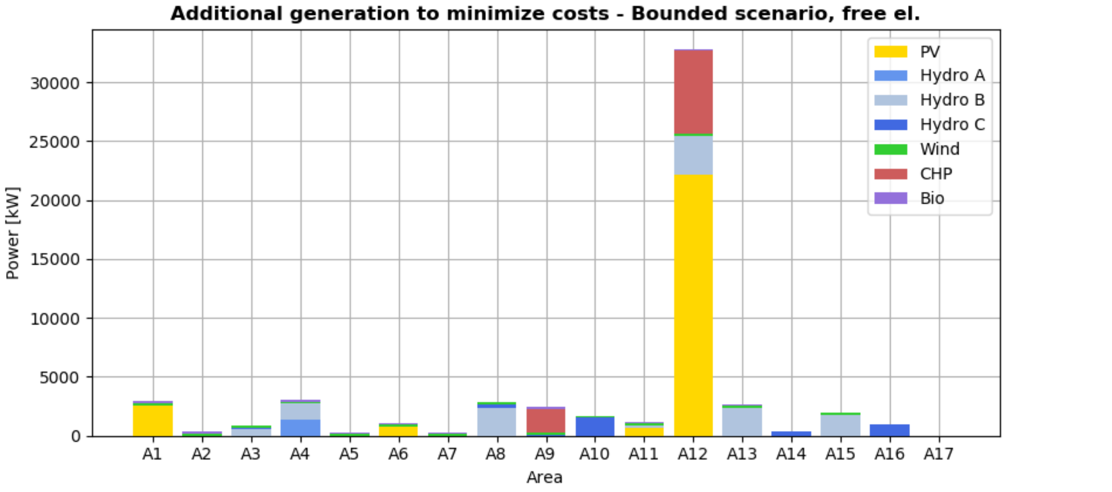


Figure 7.36 - Additional generation by area and by source to minimize costs in bounded potential and free electrification scenario

The heat pumps mix sees the presence of air-to-water heat pumps in all areas, corresponding to the fraction of households built after 2012, being that the lower O&M of this technology makes it preferable to decrease the costs (Figure 7.37). Moreover, it presents an interesting output where the areas have either null or maximum electrification. This outcome is the result of a trade-off between the investment and O&M costs of the heat pumps, the remuneration by the surplus electricity and the power limitations at the primary substation. For some areas, consequently, electrify is not economically convenient and only those areas with high generation surplus have nonnull electrification.

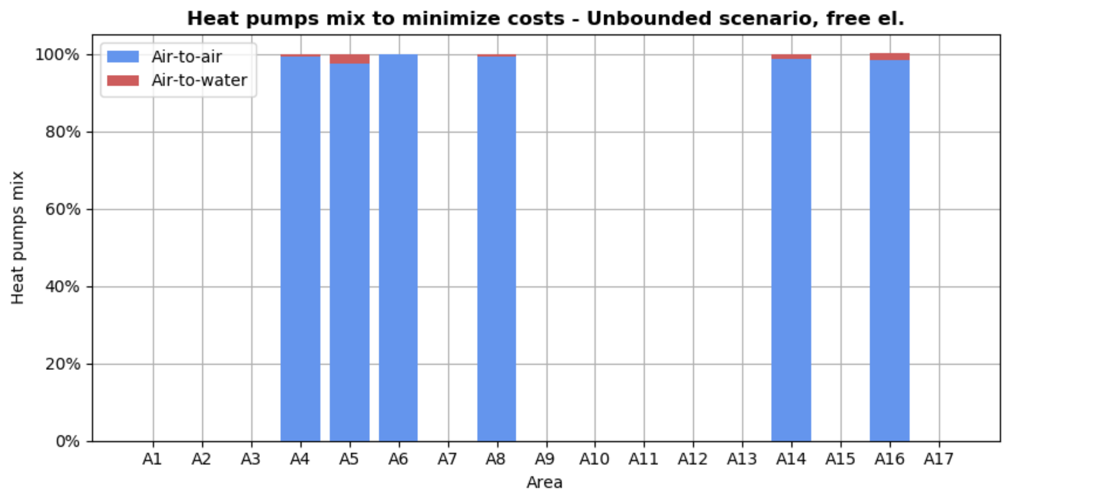


Figure 7.37 - Heat pumps mix by area to minimize costs in unbounded potential and free electrification scenario

This is furtherly demonstrated in the "bounded potential" scenario, where only areas A5 *Entreves* and A16 *Villeneuve* have nonnull electrification and, in fact, are the areas with the most negative initial power transit profile thanks to the high summer production by the hydro source (Figure 7.38). Consequently, it seems that only in the areas with high electricity generation surplus the electrification of heating is economically justified and convenient, as this surplus can be used to cover part of the heating demand instead of satisfying it with the expensive grid electricity.

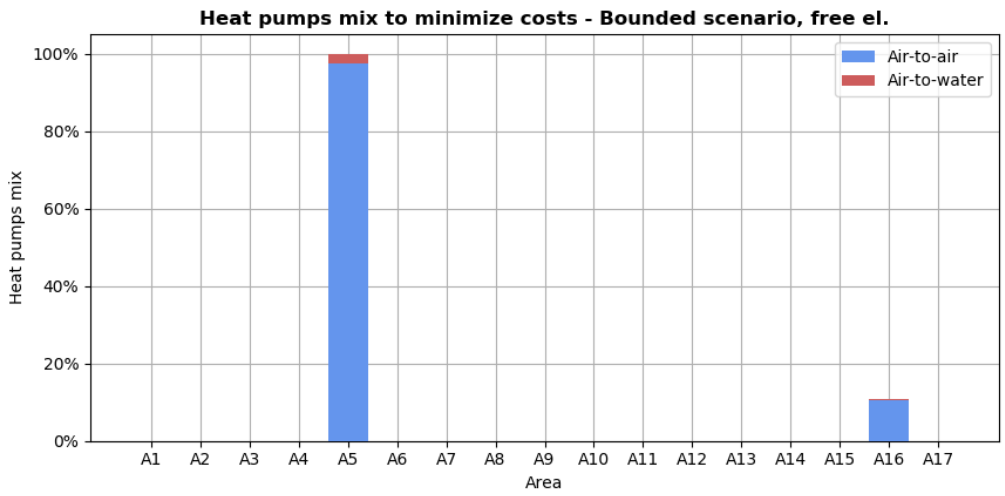


Figure 7.38 - Heat pumps mix by area to minimize costs in bounded potential and free electrification scenario

The minimum NPC in all scenarios are also presented. The “unbounded potential” scenario (Figure 7.39) shows generally lower values with respect to the “bounded potential” one (Figure 7.40).

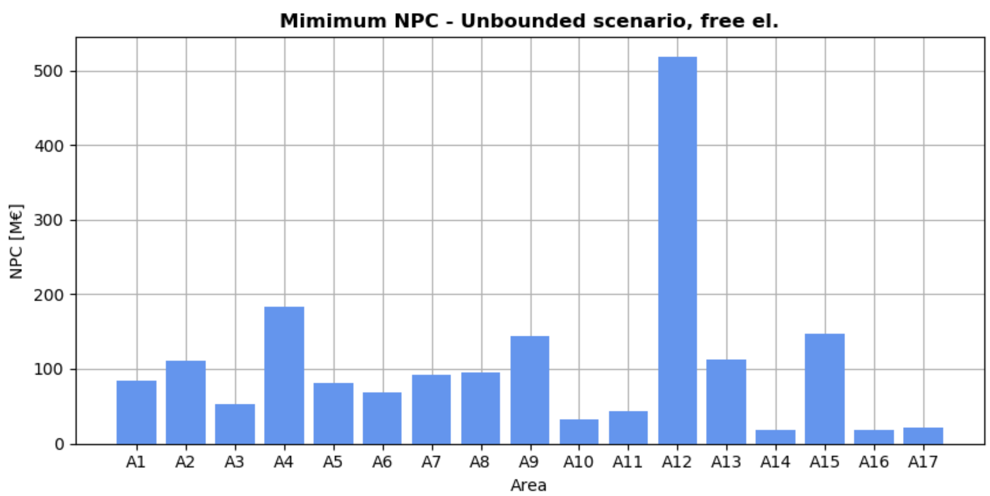


Figure 7.39 - Minimum costs by area with costs minimization in unbounded potential and free electrification scenario

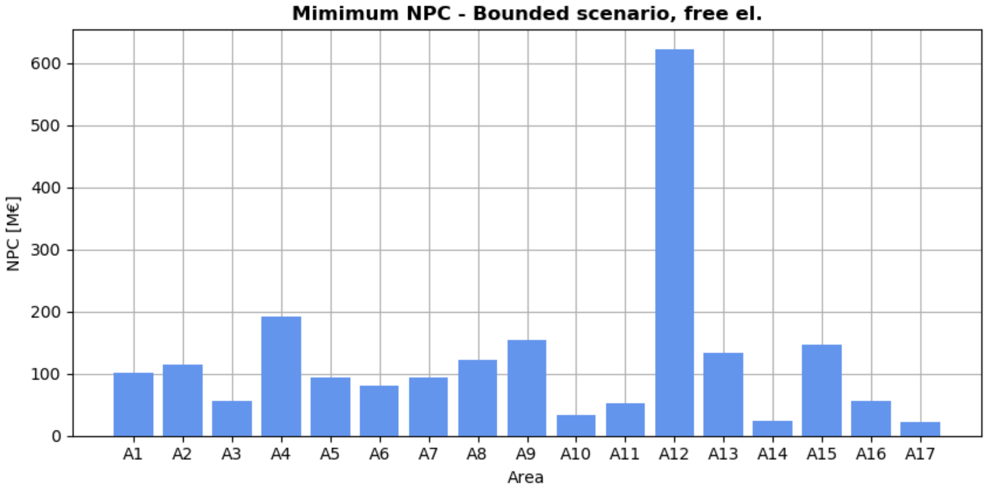


Figure 7.40 - Minimum costs by area with costs minimization in bounded potential and free electrification scenario

7.4 Global criterion

The outcomes of the model for the global criterion optimization are visualized. In general, the resulting optimal additional generation is a combination of the single objectives results, with a great importance given to hydro C, wind, CHP, PV and bio in this order in the "unbounded potential" scenario (Figure 7.41). The "bounded potential" one, on the other hand, sees more PV and hydro in all areas according to their availability, but in none of them the installed capacities reach their full potential (Figure 7.42).

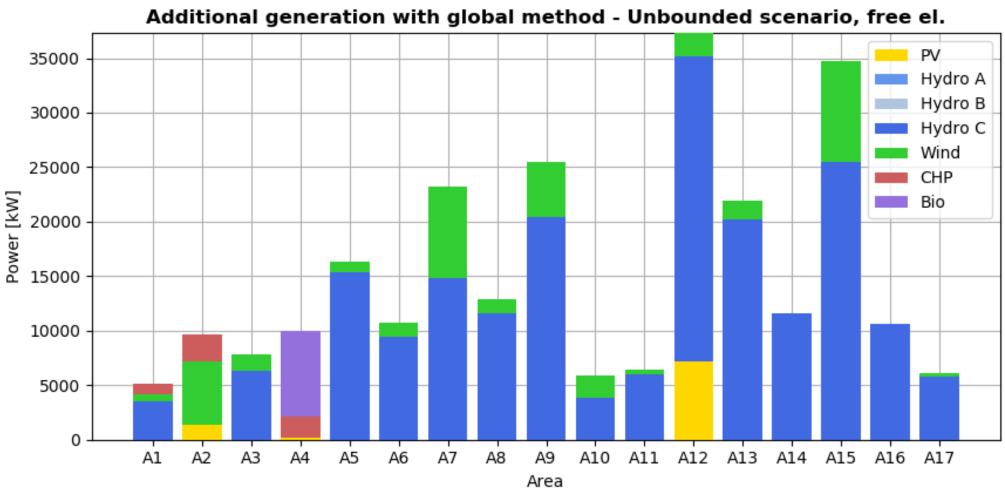


Figure 7.41 - Additional generation by area and by source with global criterion otpimization in unbounded potential and free electrification scenario

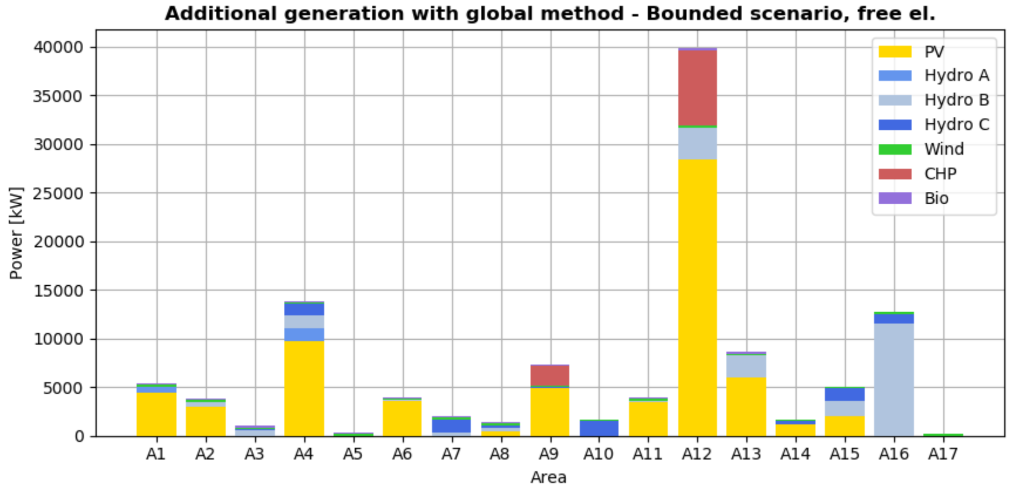


Figure 7.42 - Additional generation by area and by source with global criterion otpimization in bounded potential and free electrification scenario

The heat pumps mix is a combination of the single objective results too and, in the "unbounded potential" scenario, show an always full electrification in all areas. The only exceptions are for areas A1 *Aosta ovest* and A12 *Aosta ponte pietra* that present null electrification and area A4 *Cretaz* that reaches only 60%. In the "bounded potential" scenario also areas A11 *Pont Saint Martin 2* and A13 *Pré Saint Didier* have null electrification and area A4 Cretaz reaches only 35% (Figure 7.43). These areas correspond to those that have the most averagely positive power transit profile, reflecting again that only in the areas with a significant generation surplus electrify heating is convenient.

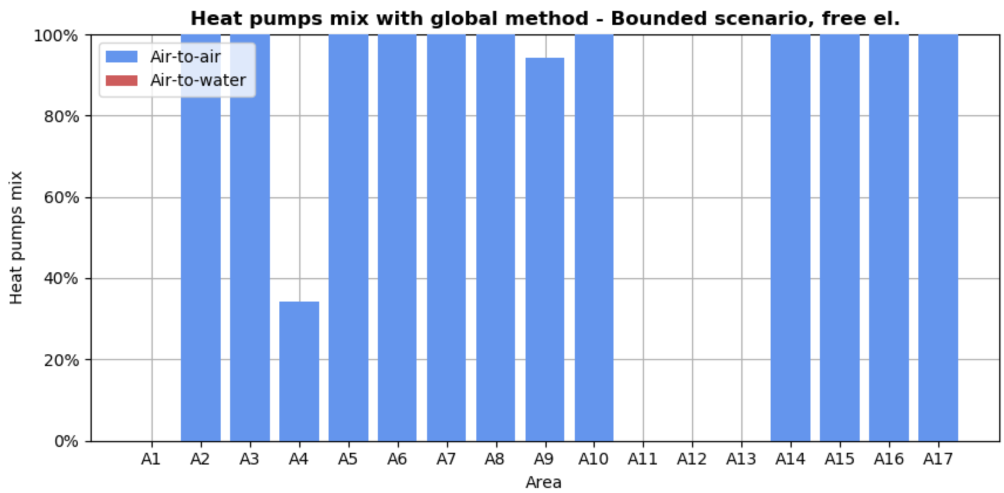


Figure 7.43 - Heat pumps mix by area with global criterion otpimization in bounded potential and free electrification scenario

The storage capacity is the output that vary the most with respect to the single objectives results. In general, in fact, for the single objectives the storage was either null or maximum, while with the global criterion it varies at a much higher extent for both the "unbounded" (Figure 7.44) and "bounded" (Figure 7.45) scenarios.

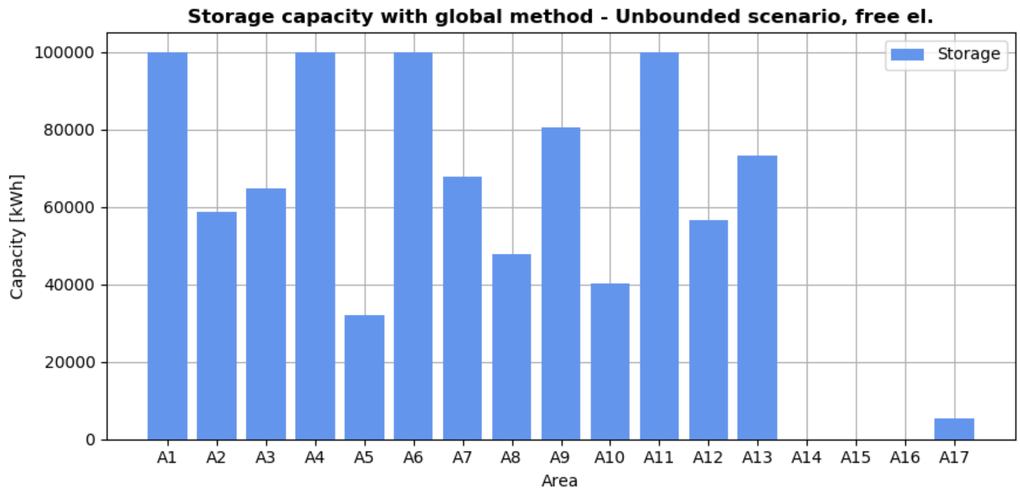


Figure 7.44 - Storage capacity by area with global criterion otpimization in unbounded potential and free electrification scenario

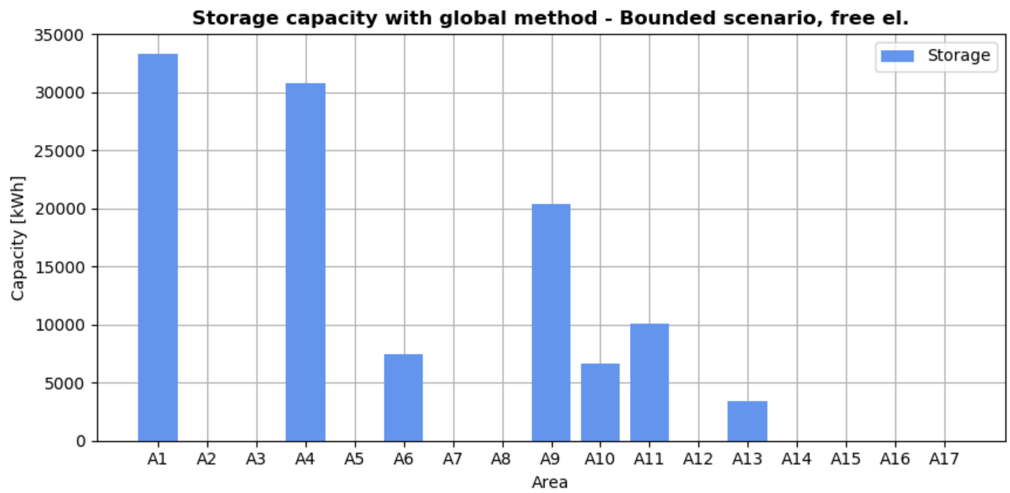


Figure 7.45 - Storage capacity by area with global criterion otpimization in bounded potential and free electrification scenario

The objectives vary differently for all areas too. In the "unbounded potential" scenario, the fluxes can increase by twice or up to 6 times for area A11 *Pont Saint Martin 2* (Figure 7.46) and the total costs can increase by up to 2.5 times as for the same area (Figure 7.47). Lastly, the emissions can increase by up to 27 times with respect to their minimum values for area A1 *Aosta ovest* (Figure 7.48).

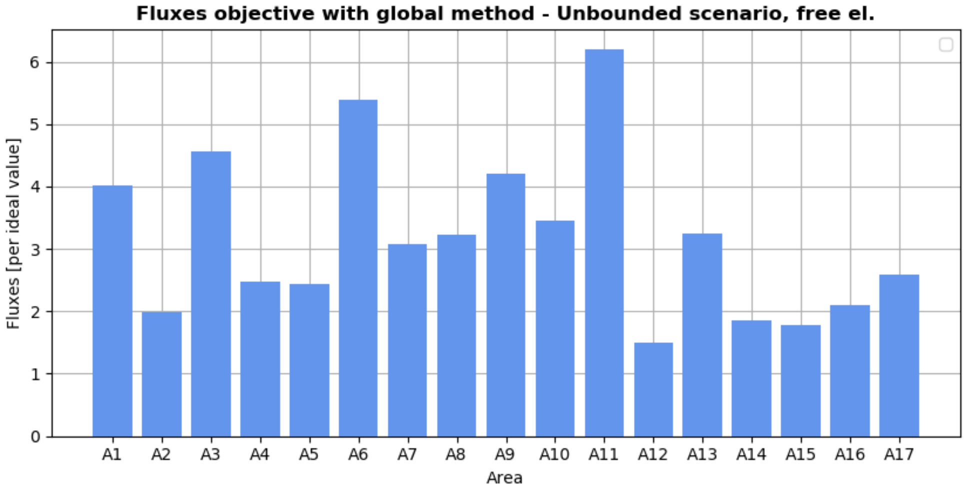


Figure 7.46 - Fluxes by area with respect to minimum values with global criterion optimization in unbounded potential and free electrification scenario

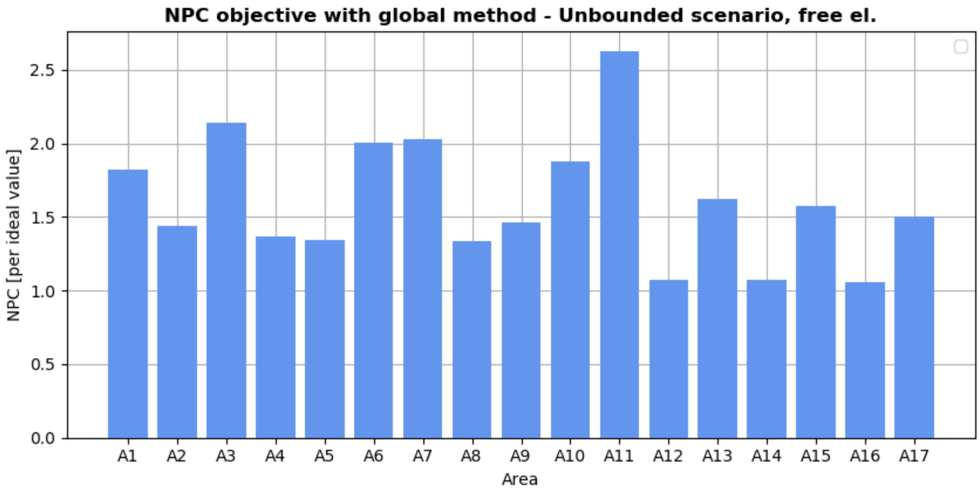


Figure 7.47 - Costs by area with respect to minimum values with global criterion optimization in unbounded potential and free electrification scenario

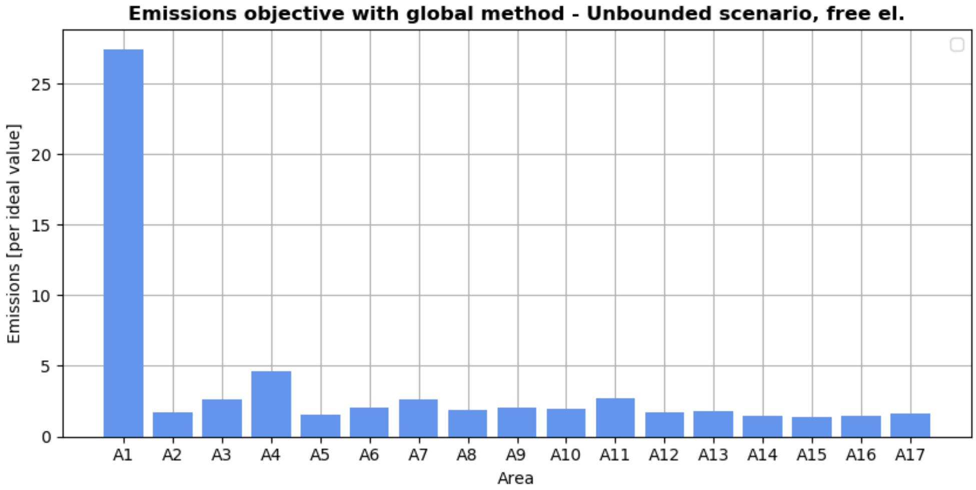


Figure 7.48 - Emissions by area with respect to minimum values with global criterion optimization in unbounded potential and free electrification scenario

The results for the “bounded potential” scenario are also visualized. The objectives vary at a much lower extent with respect to the “unbounded” case, with a maximum variation of a factor 2 for the total fluxes (Figure 7.49) and emissions (Figure 7.50) and 1.6 for the costs objective (Figure 7.51).

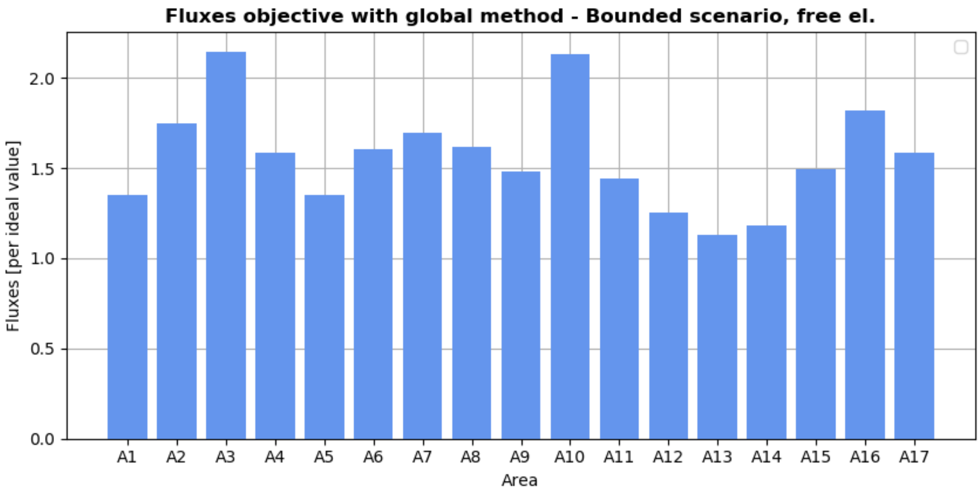


Figure 7.49 - Fluxes by area with respect to minimum values with global criterion optimization in bounded potential and free electrification scenario

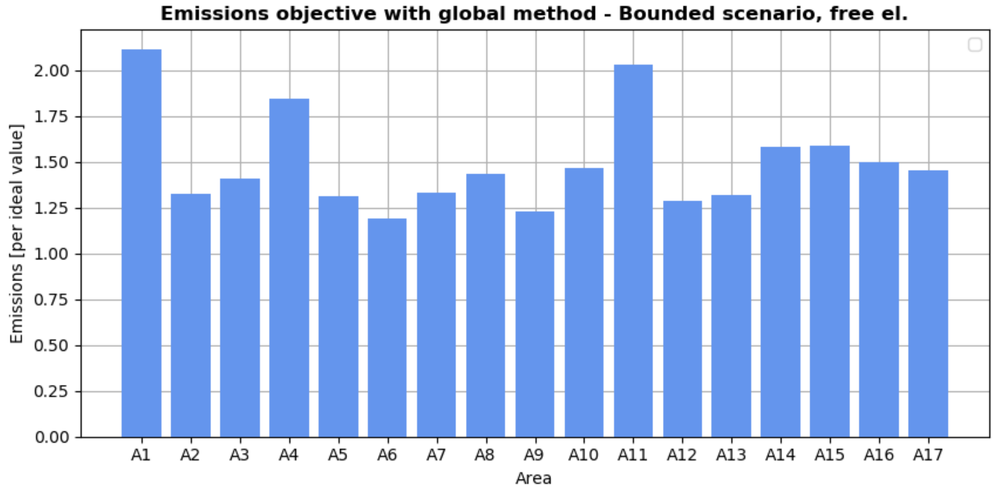


Figure 7.50 - Emissions by area with respect to minimum values with global criterion optimization in bounded potential and free electrification scenario

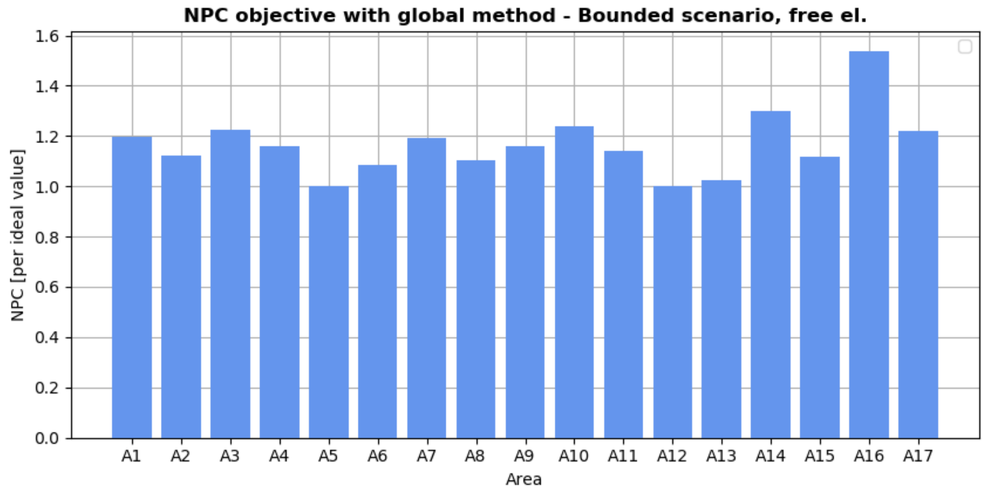


Figure 7.51 - Costs by area with respect to minimum values with global criterion optimization in bounded potential and free electrification scenario

The residual profiles for area A12 *Aosta ponte pietra* are shown in Figure 7.52, both of the global criterion and of the single objectives optimizations. Once again, the global criterion is a combination of the profiles of the latter. The residual profiles for the "bounded potential" scenario in Figure 7.53 are much closer to each other with respect to the "unbounded potential". In general, for all areas the residual profiles following the minimization of the fluxes is, obviously, the most concentrated possible around the zero. The residual profile related to the emissions minimization is the most negative as the objective is to minimize the positive profile. Lastly, the residual profile by the costs minimization is a trade-off between the minimization of the positive transit and the investment and operation costs of the new generation capacity.

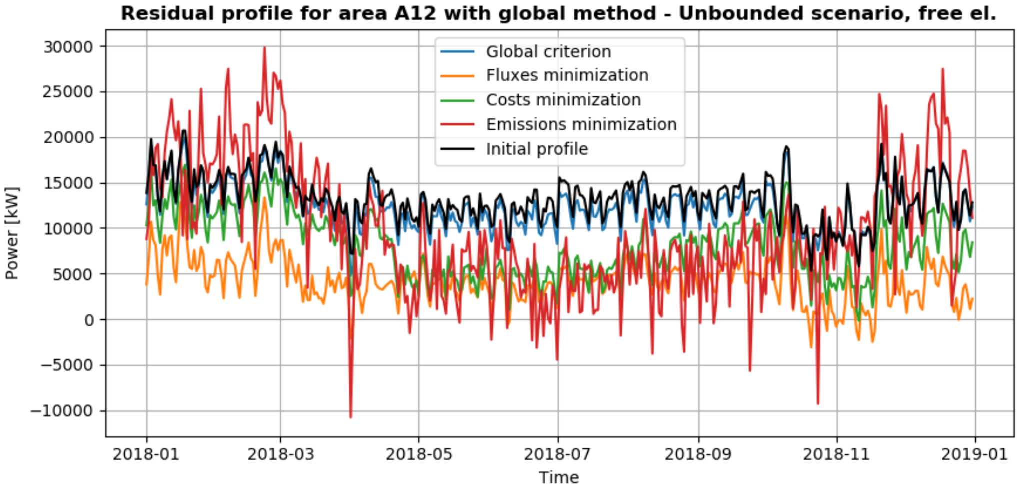


Figure 7.52 - Comparison between residual profile with global criterion and single objective optimization in unbounded potential and free electrification scenario

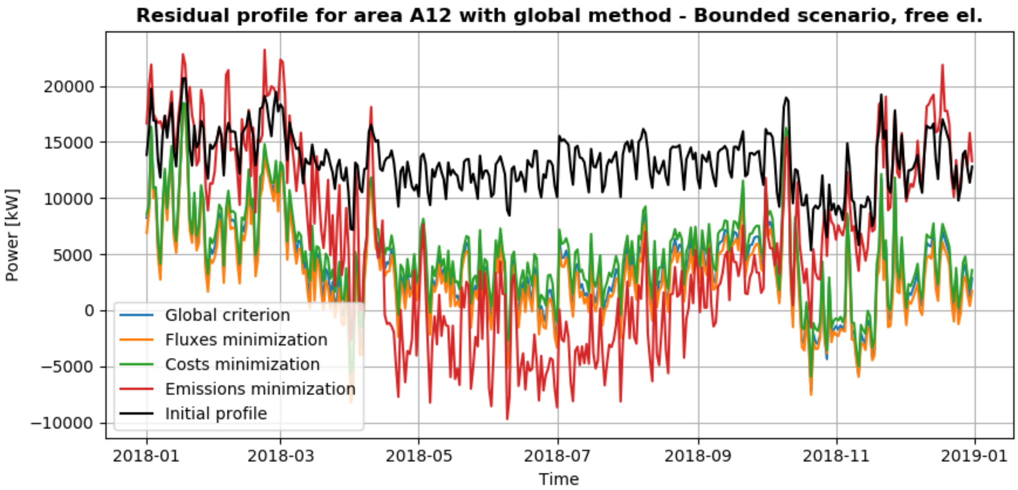


Figure 7.53 - Comparison between residual profile with global criterion and single objective optimization in bounded potential and free electrification scenario

7.5 Weighted sum method

In the weighted sum methodology, the points related to 100% weight of a certain objective – either fluxes, emissions or costs – correspond to the solutions of the single objective results obtained in the previous calculations. The additional generation shows a linear trend where the capacities by each source have no drastic change in the “unbounded potential” scenario, as shown in Figure 7.54. The results for the “bounded” scenario are also visualized in Figure 7.55. In almost all weights for area A12 *Aosta ponte pietra*, the maximum CHP and hydro B potential are installed, while the PV capacity increases with decreasing fluxes objective weight. With free electrification, the model shows a step trend with no heat pumps until 20-40% emissions objective weight, followed by a sudden increase up to 50% electrification for area A12 or even 100% for other areas (Figure 7.56 and Figure 7.57). The trend for the storage presents an even less linear trend, with often either null or full storage installed and frequent drastic changes as soon as the weights vary (Figure 7.58 and Figure 7.59).

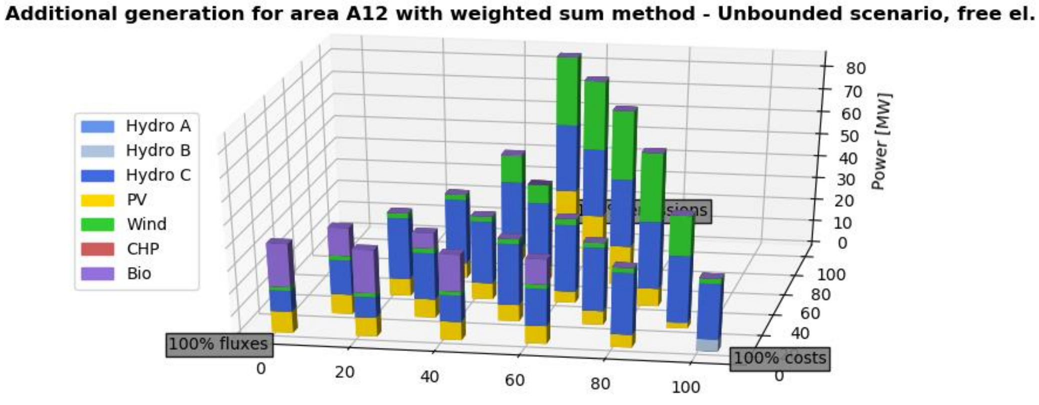


Figure 7.54 - Example of additional generation trend with weighted sum optimization in unbounded potential and free electrification scenario

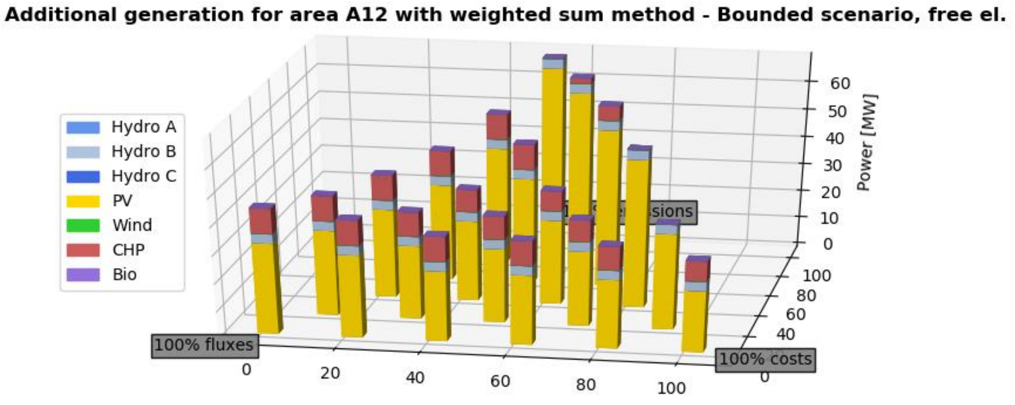


Figure 7.55 - Example of additional generation trend with weighted sum optimization in bounded potential and free electrification scenario

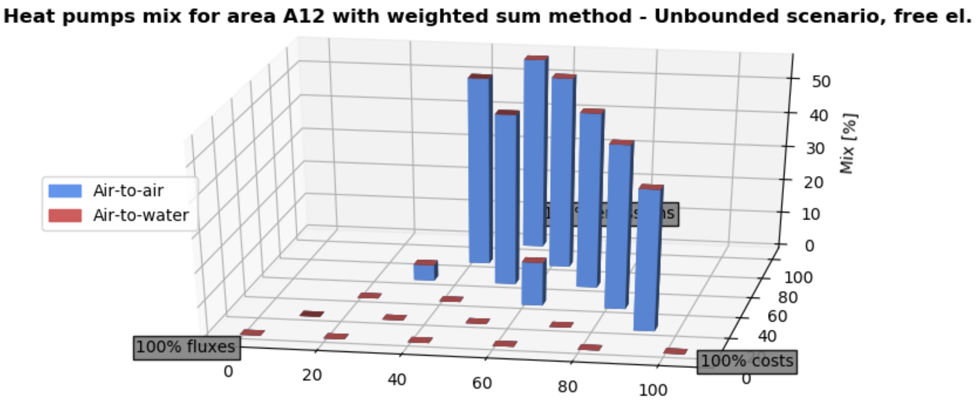


Figure 7.56 - Example of heat pumps mix trend with weighted sum optimization in unbounded potential and free electrification scenario

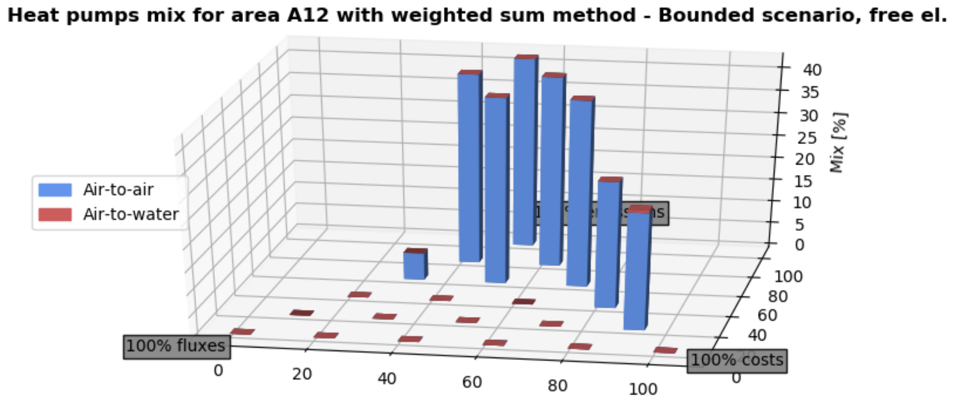


Figure 7.57 - Example of heat pumps mix trend with weighted sum optimization in bounded potential and free electrification scenario

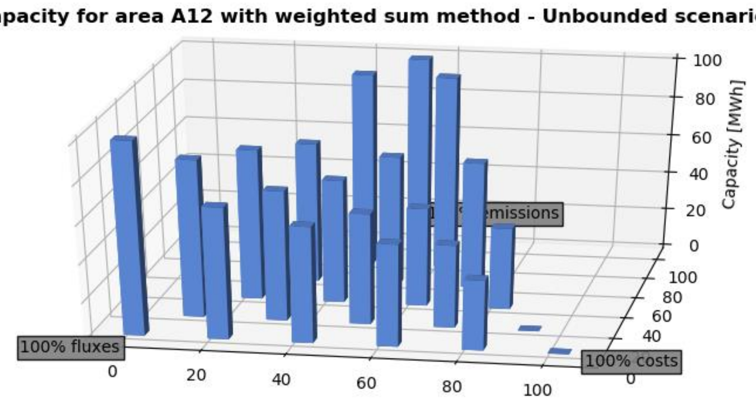


Figure 7.58 - Example of storage capacity trend with weighted sum optimization in unbounded potential and free electrification scenario

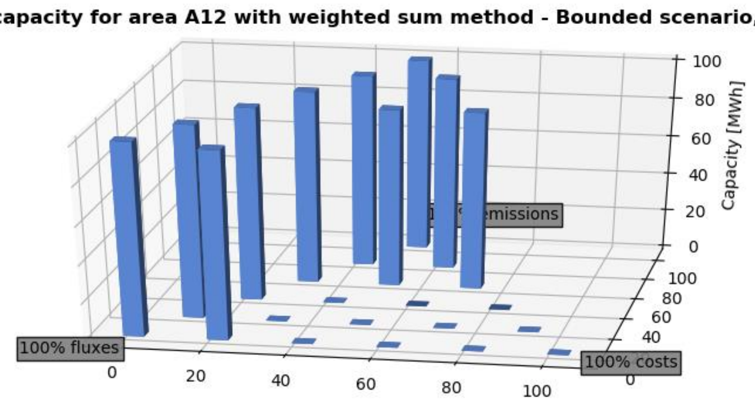


Figure 7.59 - Example of storage capacity trend with weighted sum optimization in bounded potential and free electrification scenario

Each objective is visualized as it varies with respect to the ideal value – i.e. the one resulting from the single objective optimization. For all areas, the total fluxes are slightly more influenced by the emissions than the costs weight and can be as high as 3 to 4 times the ideal value at 0% fluxes weight for area A12 *Aosta ponte pietra* (Figure 7.60) or up to 200 times for A1 *Aosta ovest*. Similarly, the emissions are more influenced by the fluxes weight and show a maximum increase of 2 for area A12 (Figure 7.61) or up 40 times for area A16 *Villeneuve*. Lastly, the costs objective is the one that varies the least as the weights change but that shows the most drastic variation as soon as the costs weight is no longer 100% (Figure 7.62).

In the “bounded potential” scenario, all objectives vary at a much lower extent with respect to the “unbounded” case. This time, the fluxes objective in area A12 *Aosta ponte pietra* is equally influenced by both other two objectives, with a singularity in proximity of 100%

costs weight (Figure 7.63). The same singularity is present in the emissions (Figure 7.64) and costs trend (Figure 7.65).

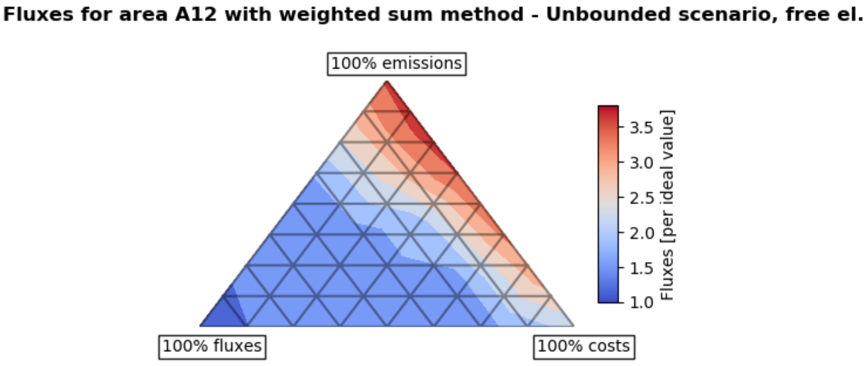


Figure 7.60 - Example of fluxes trend with respect to the minimum value with weighted sum optimization in unbounded potential and free electrification scenario

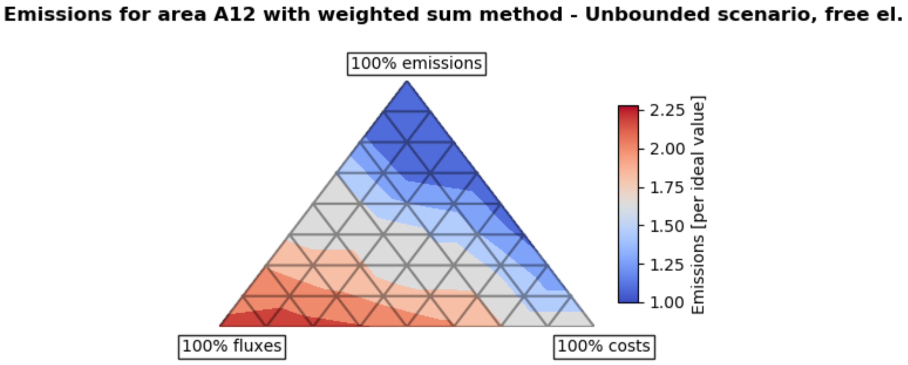


Figure 7.61 - Example of emissions trend with respect to the minimum value with weighted sum optimization in unbounded potential and free electrification scenario

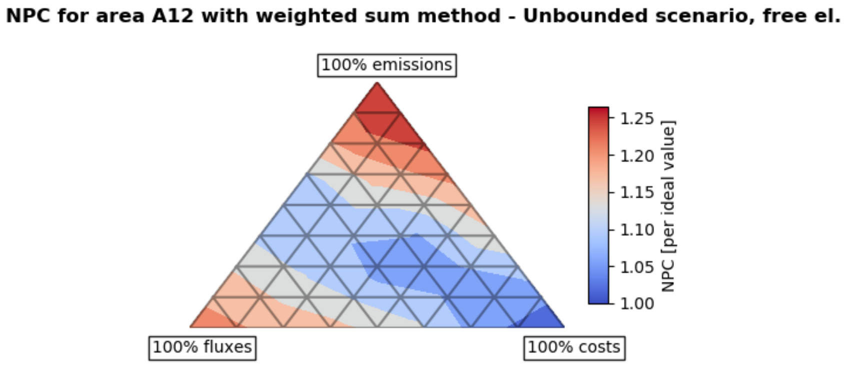


Figure 7.62 - Example of costs trend with respect to the minimum value with weighted sum optimization in unbounded potential and free electrification scenario

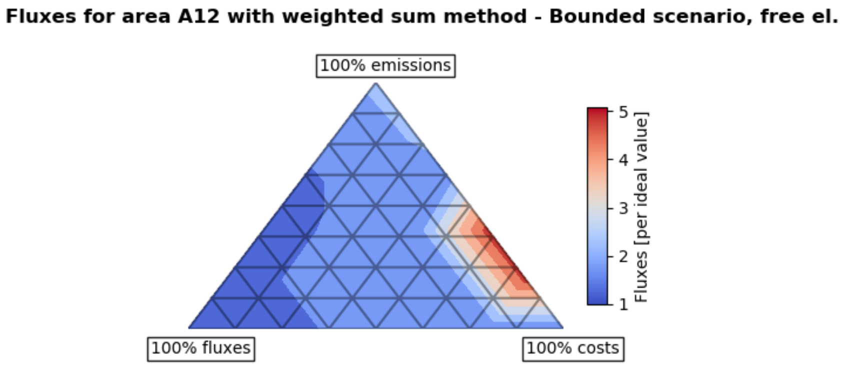


Figure 7.63 - Example of fluxes trend with respect to the minimum value with weighted sum optimization in bounded potential and free electrification scenario

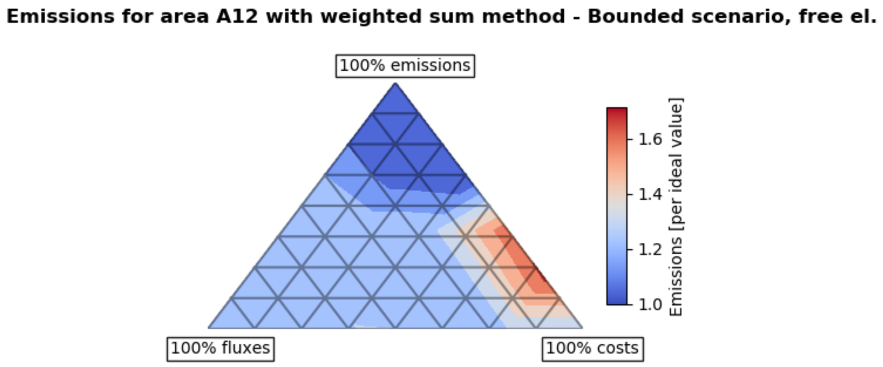


Figure 7.64 - Example of emissions trend with respect to the minimum value with weighted sum optimization in bounded potential and free electrification scenario

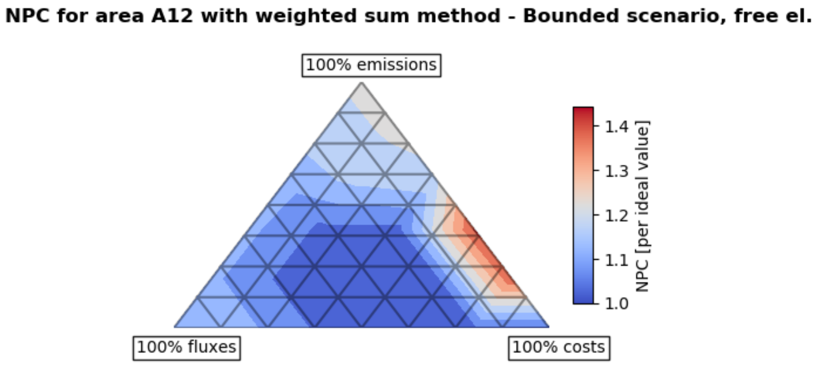


Figure 7.65 - Example of costs trend with respect to the minimum value with weighted sum optimization in bounded potential and free electrification scenario

Chapter 8
Conclusions

The model presented in this thesis has been proved to be able to perform the optimization of an energy planning by considering a multiplicity of goals merged in a multi-objective problem. The objectives that have been considered are the minimization of the fluxes through the electric distribution grid, the minimization of the emissions by the energy consumption for power and heating and, lastly, the minimization of the costs for the consumers. These objectives can either be pursued by the policy maker, by the citizens in an energy community or by both of them, depending on the preferences and needs of each actor. Furthermore, the model considers not only the current electricity demand but the incremental load given by the electrification of heating, following the direction set by the most recent Italian and European energy strategies, and optimizes the heat pumps adoption according to the objective functions listed above.

After presenting all the elements of the model regarding the generation, the power transit through the electric distribution grid and the heating demand, the problem is first defined in a global criterion approach able to optimize all the objectives at the same time, such that the sum of the normalized differences between the punctual and the lowest values possible is minimized:

$$Objective_{Global} = min\left[\left(\frac{Fluxes_{Tot} - Fluxes_0}{Fluxes_0}\right) + \left(\frac{Emissions_{Tot} - Emissions_0}{Emissions_0}\right) + \left(\frac{NPC_{Tot} - NPC_0}{NPC_0}\right)\right]$$

where $Fluxes_0$, $Emissions_0$ and NPC_0 are the minimum values of each objective, obtained by singularly minimizing each function. Secondly, the problem is solved by means of a weighted sum methodology, which obtains a different set of optimal solutions by assigning a different weight to each objective in a number of diverse scenarios:

$$Objective_{Weigth} = min\left[\alpha \cdot \frac{Fluxes_{Tot}}{Fluxes_0} + \beta \cdot \frac{Emissions_{Tot}}{Emissions_0} + \gamma \cdot \frac{NPC_{Tot}}{NPC_0}\right]$$

where α, β and γ are the weights assigned to each objective in the weighted sum problem. The results have the shape of a ternary diagram, since the sum of α, β and γ is unitary. Intuitively, the higher the weight of an objective, the closer the results to its ideal value and, when a weight becomes 100%, the results correspond to the single objective ones.

Applying the model to region Valle d'Aosta, in particular to each area defined as the set of municipalities afferent to a single transformation primary substation, the minimization of the fluxes sees a high presence of the bio source, CHP and hydro classified as "type C" – i.e. the ones with most constant profile along the year, – null electrification and maximum storage for all areas. The minimization of the emissions, instead, sees the installation of more hydro, wind and PV – i.e. the sources with the lowest emission factors, – a full electrification of heating up to the maximum allowed by the power limit of the primary substation and full storage. Lastly, minimizing the costs for the consumers implies a high presence of all types of hydro, an electrification varying across the areas depending on their load profiles and null storage. According to the results obtained in the multi-objective optimization, four main outcomes can be observed:

1) Hydro C – i.e. the type that after the clustering process was observed to have the most constant normalized production along the year – is the most suitable source to minimize the fluxes, emissions and costs at the same time.
2) Even in absence of high availability of hydro C, installing PV capacity is convenient to minimize the fluxes, emissions and costs, with an extent that depends on the area and on the weights given to each objective function, reflecting the great importance given to the solar PV to reach the renewable targets by 2030 in the PNIEC (see Chapter 2.1).
3) Electrify heating is a good option when minimizing the emissions but is economically convenient only with a high electricity generation surplus and is never selected when minimizing the total fluxes, consequently the incentives to the installation of heat pumps can greatly influence their adoption.
4) Install storage capacity is convenient to decrease both emissions and fluxes but is not useful when minimizing the costs, therefore an incentive to the instant self-consumption can help overcome this economical barrier and unlock the storage potential.

The model introduced in this thesis, however, is based on some important assumptions necessary to avoid the need to account for the energy and monetary exchanges among different energy communities in a single area and to simplify the model itself, which are that 1) all citizens living in an area join the energy community, and 2) only one energy community is introduced in each area. These assumptions may be not enough verisimilar for certain areas and, together with other simplifications, the resulting output cannot be fully representing of the options and solutions concerning the optimal evolution of the related energy system. Among the main further developments, therefore, some features could be introduced:

- Model not only the direct costs but the externalities too, since the primary purpose of an energy community is not of economical but rather of social nature and, consequently, some positive externalities such as local development or added value should be considered as well;

- Simulate an electrification of not only the heating sector, but also transport and industry;
- Introduce the actual electricity demand rather than the electrical load through the transformation primary substation, so that considerations on incentives to the self-consumption could be performed;
- Couple the electrical with the thermal model, such that the available solutions to decarbonise heat with nonelectrical technologies – district heating, biogas, biomass, etc – can be optimised too according to their availability;
- Consider demand-response schemes.

Moreover, relatively to the case study:

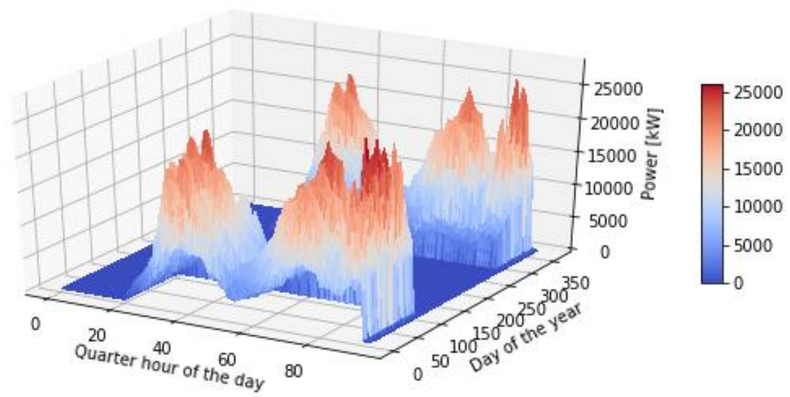
- Cluster all sources, especially the hydro, in a more detailed way, by knowing the actual features of each plant;
- Better estimate the real potential of each source in each area;
- Estimate the potential of technologies other than batteries, such as pumped hydro, to better represent the storage potential of each area;
- Perform a sensitivity analysis in each optimization, where the input data are disturbed and different results are eventually obtained, therefore starting an iterative process that ends as soon as the results obtained happen to be within a certain predefined range and obtaining a more solid set of solutions;
- Consider the technical constraints related to the hosting capacity of the LV distribution grid to verify the actual feasibility of installing additional generation capacity.

In any case, the model constitutes a first step in the construction of a tool for the policy maker to simulate the outcomes of sharing part of the decision-making power in favour of the citizens and explore how the energy system would develop by considering different objectives. These objectives represent the preferences, either belonging to the policy maker or to the energy community, that have the power to shape the evolution of the energy system in a certain area. In this way the policy maker can evaluate how the optimal development for the energy community can be functional to the achievement of his or her own objectives. With this information in mind, the policy maker could have the possibility to set a number of rules, incentives and constraints to influence the local energy system development towards the objectives that he or she has the necessary information to know that bring the major benefits to the society.

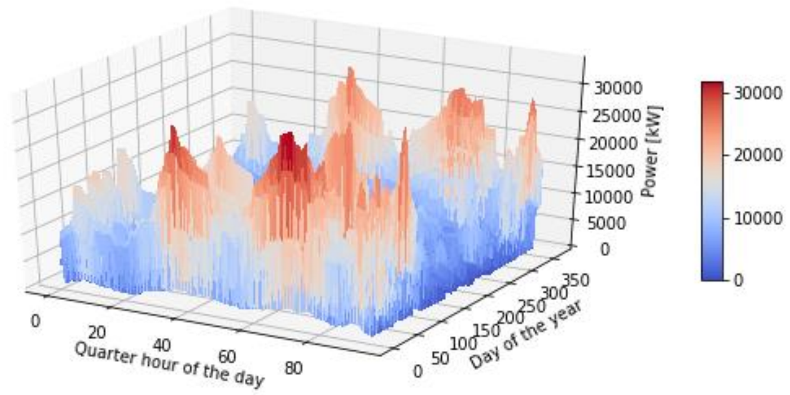
Appendix A – Heating profiles

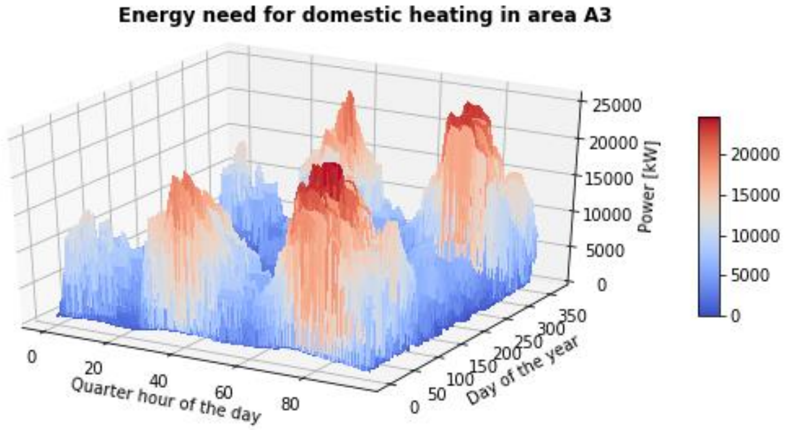
In this appendix the results regarding the profiles of the heating demand for all areas are shown. The main differences that can be noticed are related to the climatic zone to which the municipalities belong: the municipalities in those areas where the heating demand is null at night time and during summer are all in the climatic zone “E”, whereas most of the municipalities in the areas that have always nonnull heating demand belong to the climatic zone “F”, that allows the heating plant to be switched on without any time constraints. Notice that the profiles exclusively refer to the heating demand by non-electric sources, therefore both electric heaters and heat pumps are not considered: in fact, this is the heating demand that will be electrified with heat pumps for the purposes of the model.

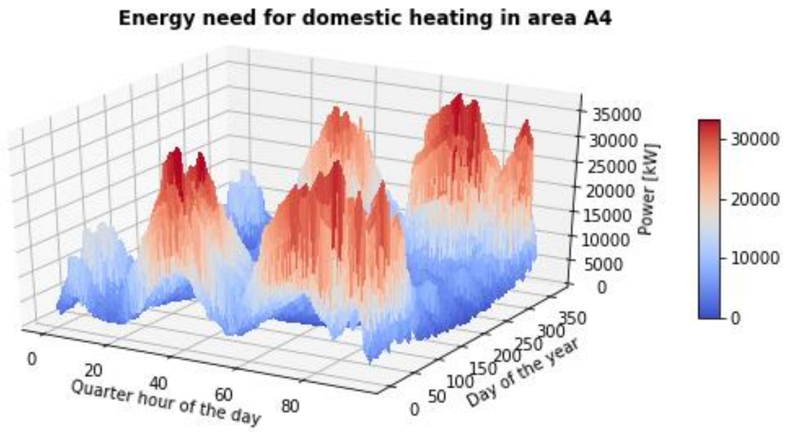
Energy need for domestic heating in area A1

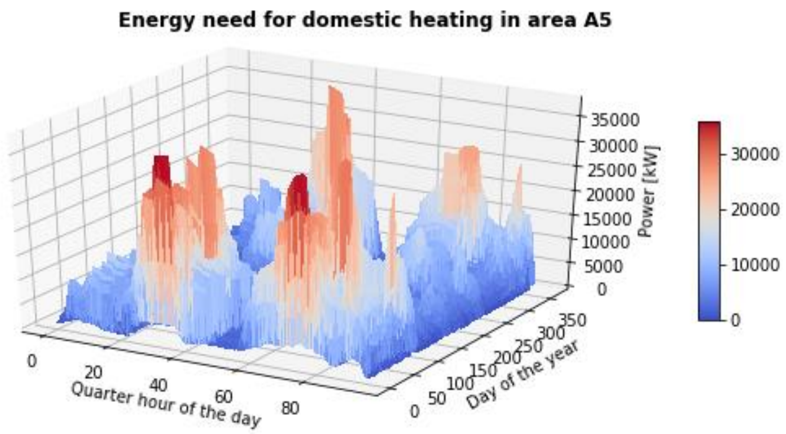


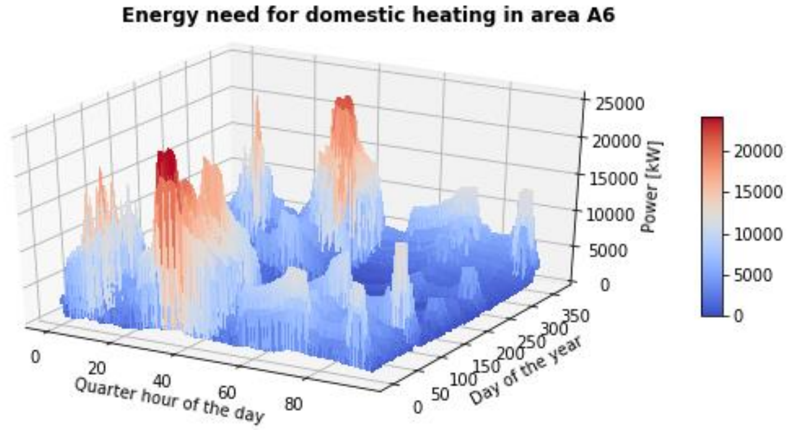
Energy need for domestic heating in area A2

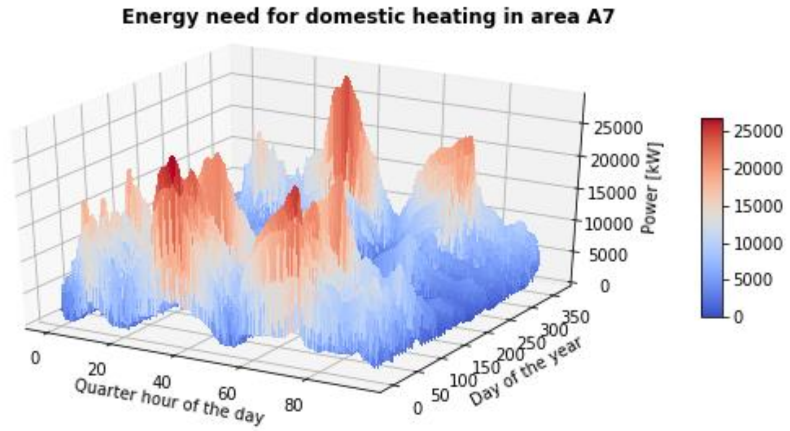


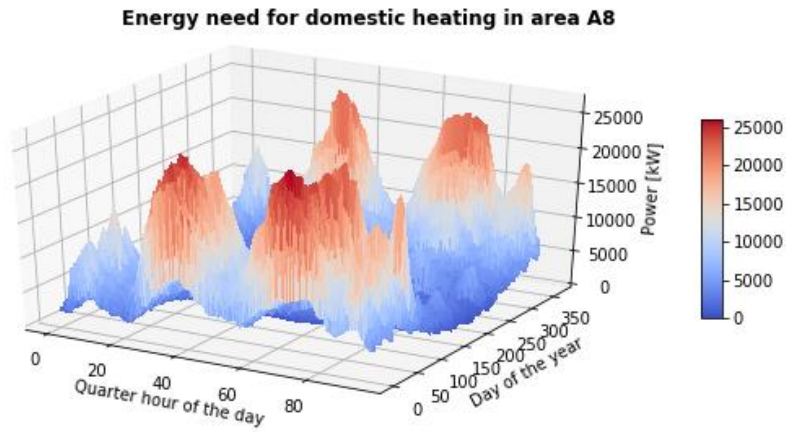

Energy need for domestic heating in area A3
Power [kW]
Quarter hour of the day
Day of the year

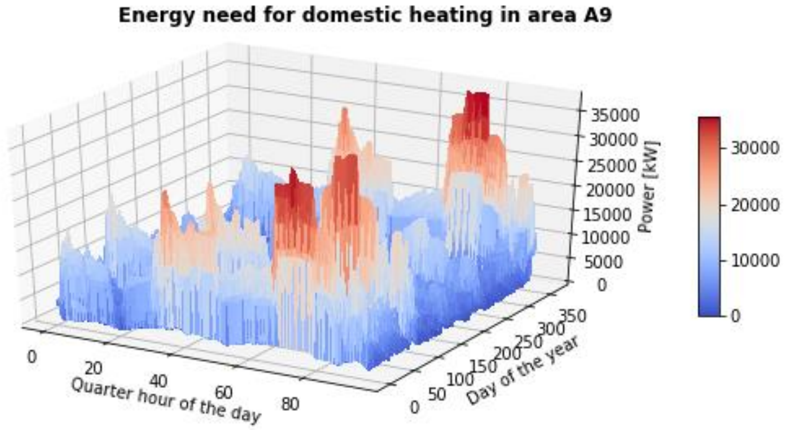

Energy need for domestic heating in area A4
Power [kW]
Quarter hour of the day
Day of the year

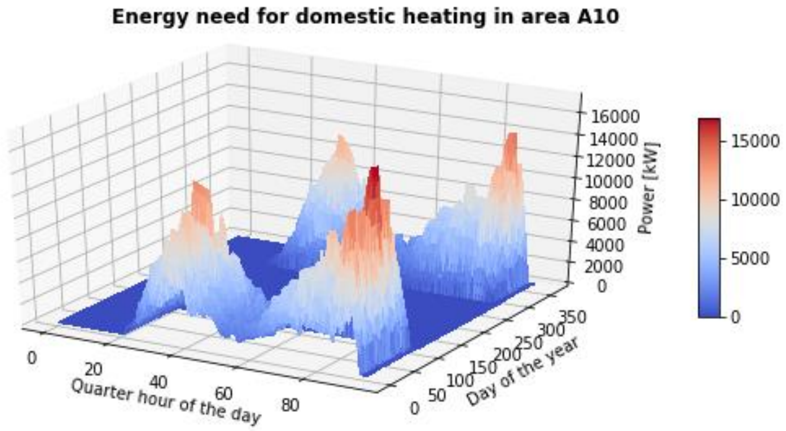

Energy need for domestic heating in area A5
Power [kW]
Quarter hour of the day
Day of the year

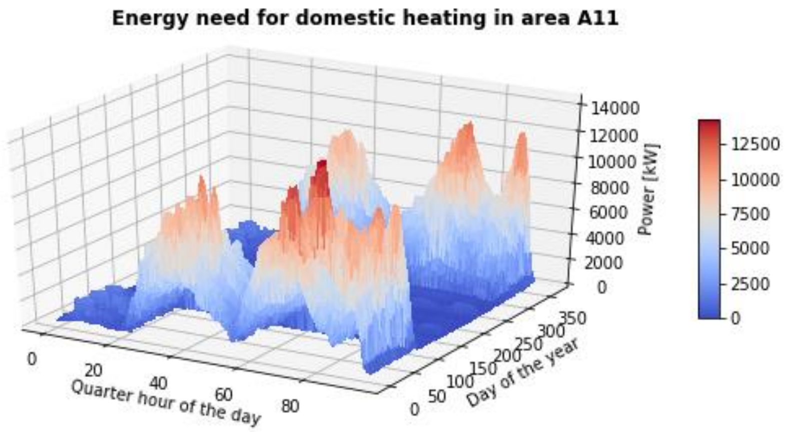

Energy need for domestic heating in area A6
Quarter hour of the day
Day of the year
Power [kW]
0
20
40
60
80
0
50
100
150
200
250
300
350
0
5000
10000
15000
20000
25000

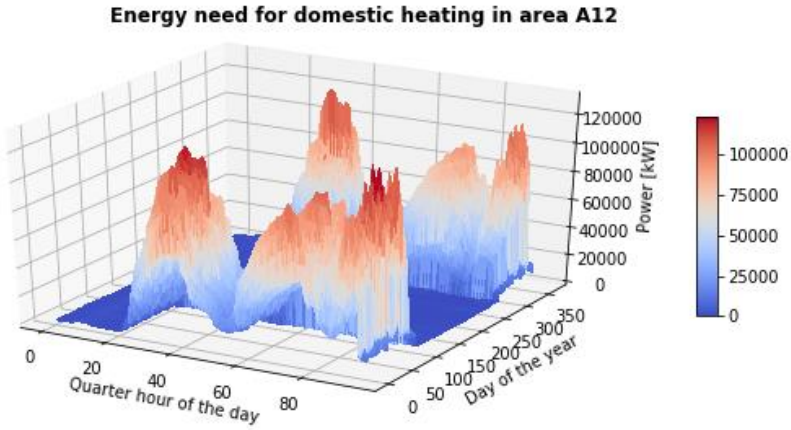

Energy need for domestic heating in area A7
Quarter hour of the day
Day of the year
Power [kW]
0
20
40
60
80
0
50
100
150
200
250
300
350
0
5000
10000
15000
20000
25000

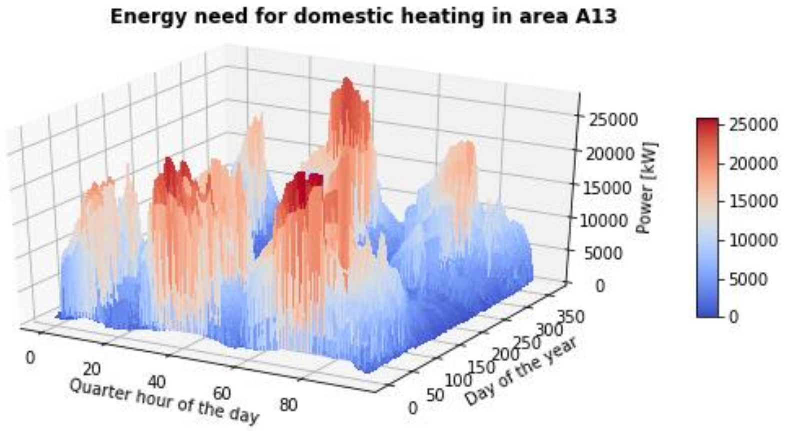

Energy need for domestic heating in area A8
Quarter hour of the day
Day of the year
Power [kW]
0
20
40
60
80
0
50
100
150
200
250
300
350
0
5000
10000
15000
20000
25000

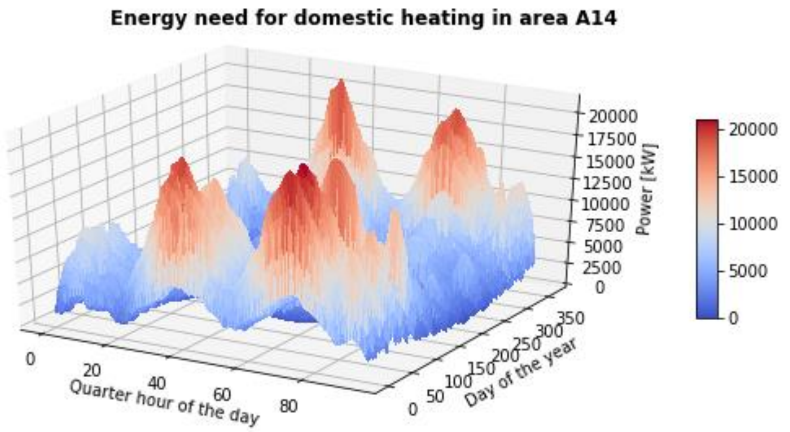

Energy need for domestic heating in area A9
Quarter hour of the day
Day of the year
Power [kW]

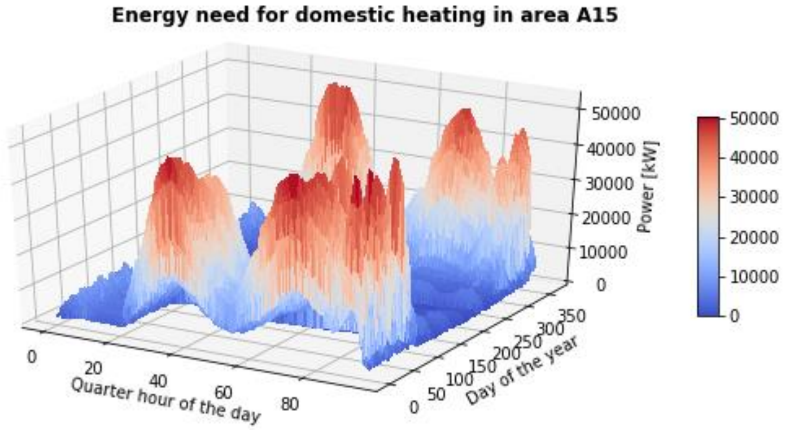

Energy need for domestic heating in area A10
Quarter hour of the day
Day of the year
Power [kW]

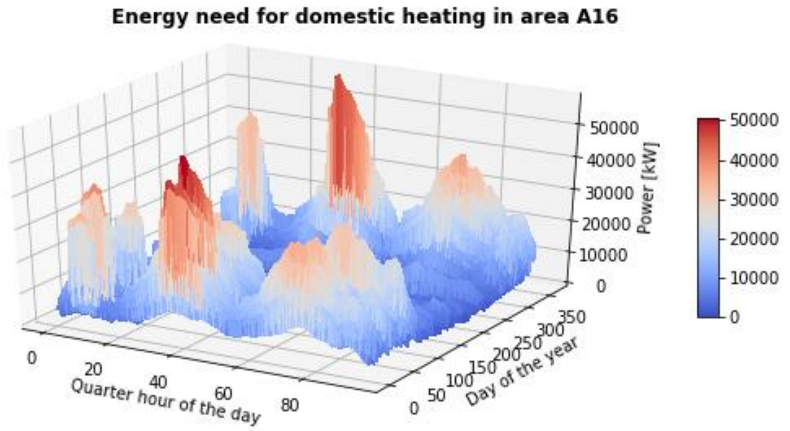

Energy need for domestic heating in area A11
Quarter hour of the day
Day of the year
Power [kW]

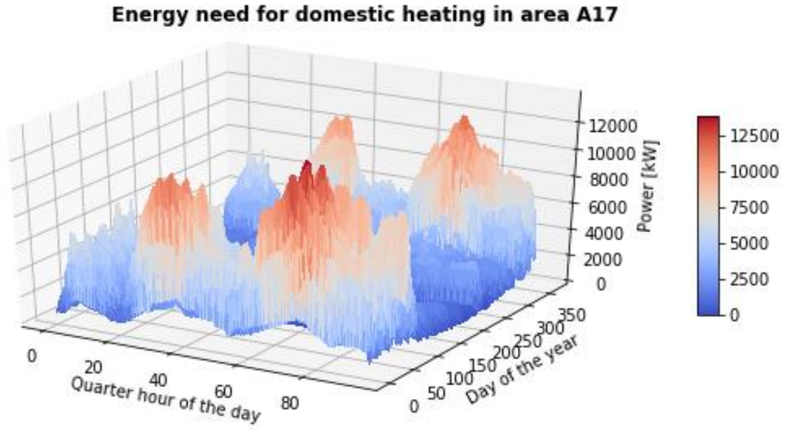

Energy need for domestic heating in area A12
Power [kW]
Quarter hour of the day
Day of the year
0
20
40
60
80
0
50
100
150
200
250
300
350
0
20000
40000
60000
80000
100000
120000
0
25000
50000
75000
100000


Energy need for domestic heating in area A13
Power [kW]
Quarter hour of the day
Day of the year
0
20
40
60
80
0
50
100
150
200
250
300
350
0
5000
10000
15000
20000
25000
0
5000
10000
15000
20000
25000


Energy need for domestic heating in area A14
Power [kW]
Quarter hour of the day
Day of the year
0
20
40
60
80
0
50
100
150
200
250
300
350
0
2500
5000
7500
10000
12500
15000
17500
20000
0
5000
10000
15000
20000


Energy need for domestic heating in area A15
Power [kW]
Quarter hour of the day
Day of the year
0
20
40
60
80
0
50
100
150
200
250
300
350
0
10000
20000
30000
40000
50000

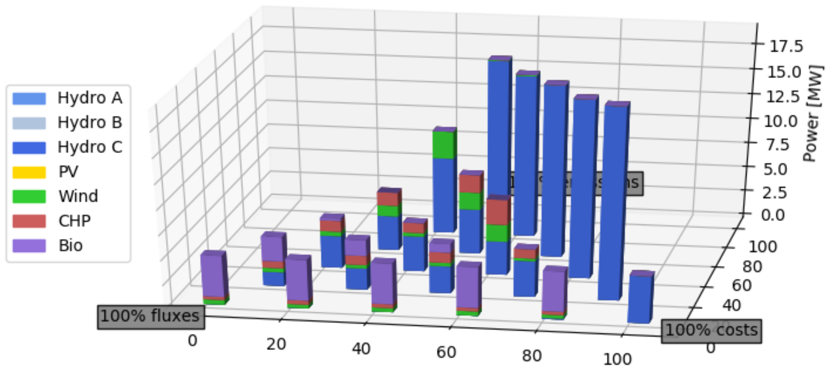

Energy need for domestic heating in area A16
Power [kW]
Quarter hour of the day
Day of the year
0
20
40
60
80
0
50
100
150
200
250
300
350
0
10000
20000
30000
40000
50000


Energy need for domestic heating in area A17
Power [kW]
Quarter hour of the day
Day of the year
0
20
40
60
80
0
50
100
150
200
250
300
350
0
2000
4000
6000
8000
10000
12000
2500
5000
7500
10000
12500

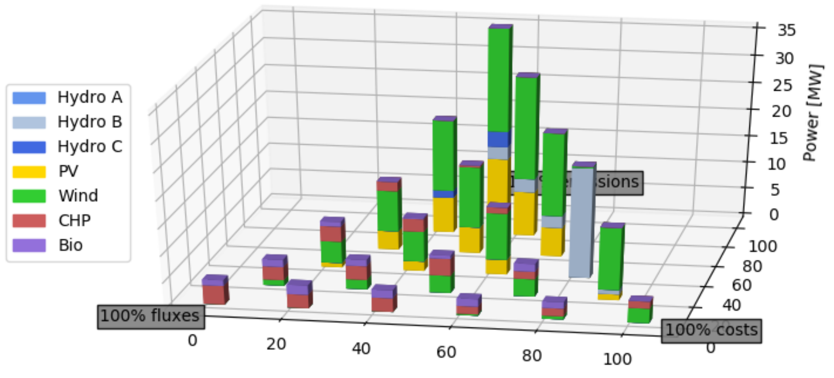
Appendix B – Unbounded potential generation

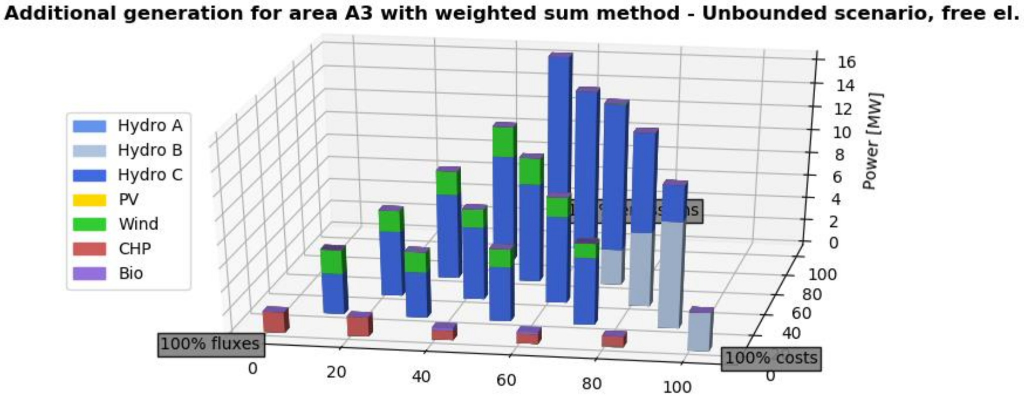
This appendix reports the results of the optimization with weighted sum methodology regarding the “unbounded potential” additional generation.

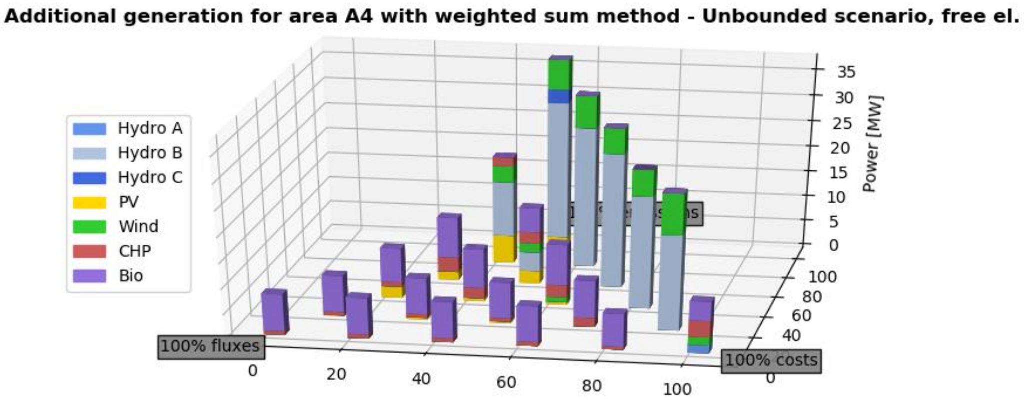
Additional generation for area A1 with weighted sum method - Unbounded scenario, free el.

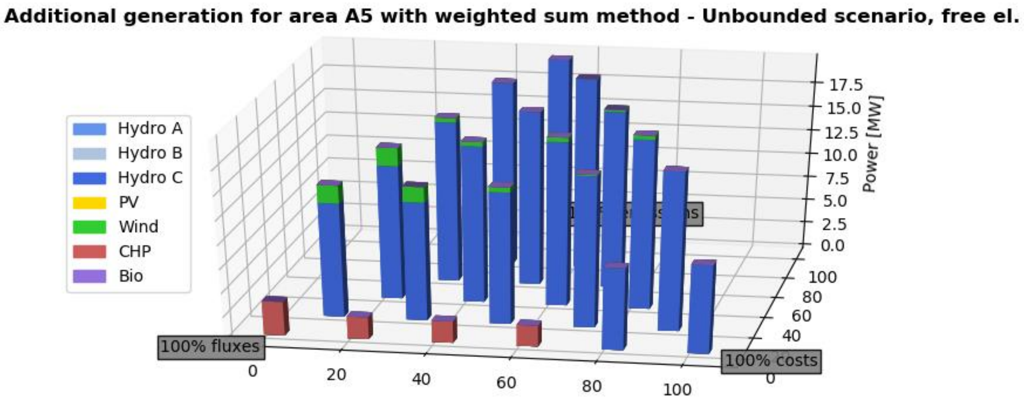


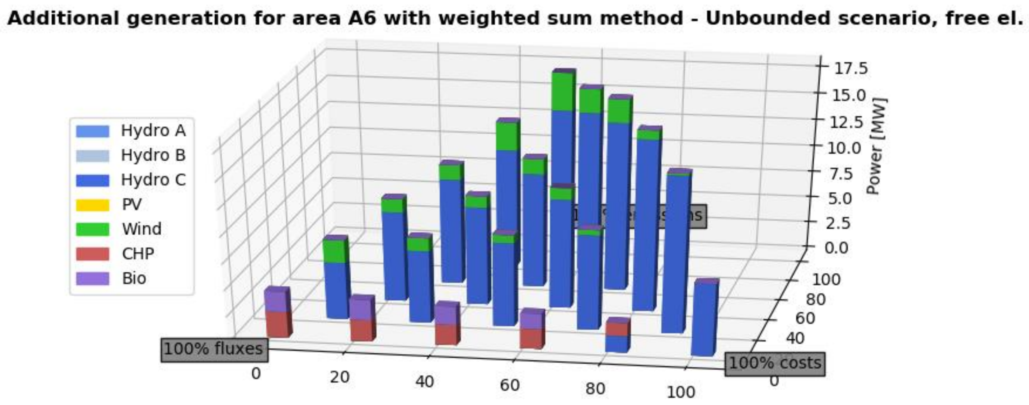
Additional generation for area A2 with weighted sum method - Unbounded scenario, free el.

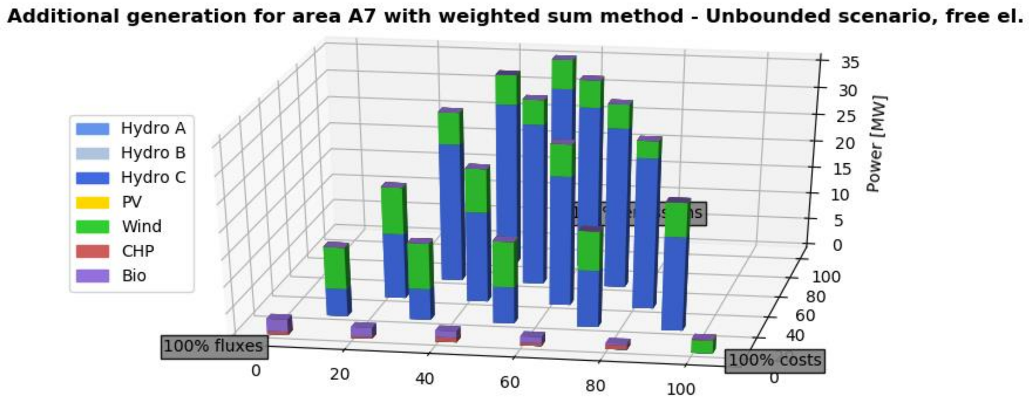


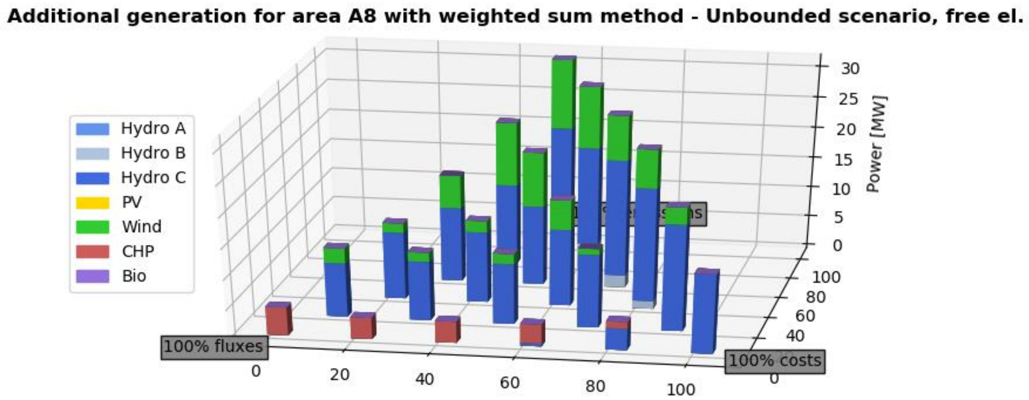

Additional generation for area A3 with weighted sum method - Unbounded scenario, free el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100
0
2
4
6
8
10
12
14
16

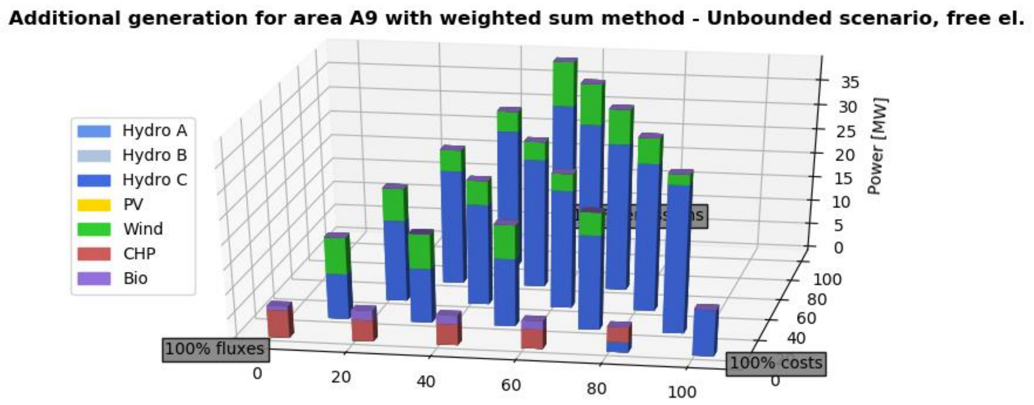

Additional generation for area A4 with weighted sum method - Unbounded scenario, free el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100
0
5
10
15
20
25
30
35

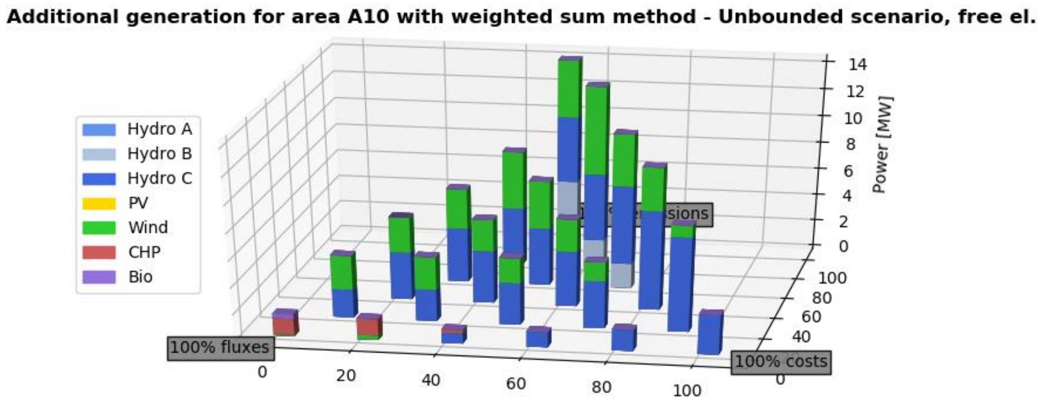

Additional generation for area A5 with weighted sum method - Unbounded scenario, free el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100
0.0
2.5
5.0
7.5
10.0
12.5
15.0
17.5

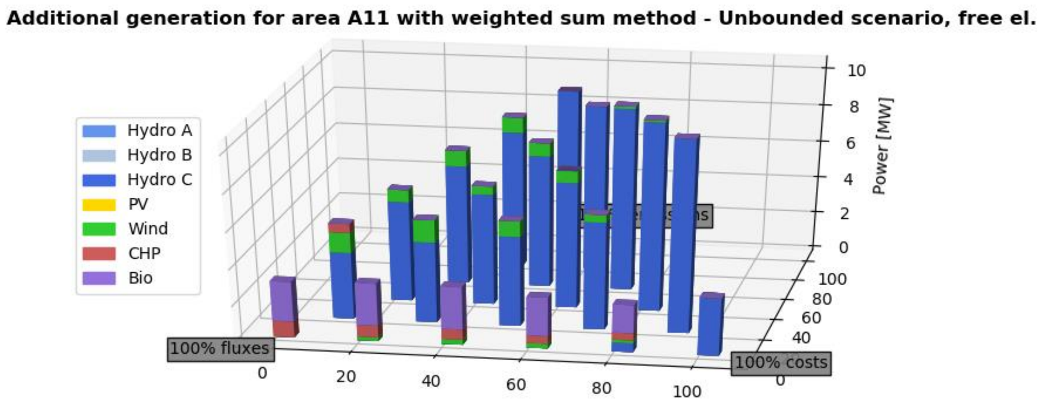

Additional generation for area A6 with weighted sum method - Unbounded scenario, free el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
17.5
15.0
12.5
10.0
7.5
5.0
2.5
0.0
100
80
60
40
0
100% fluxes
100% costs
0
20
40
60
80
100


Additional generation for area A7 with weighted sum method - Unbounded scenario, free el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
35
30
25
20
15
10
5
0
100
80
60
40
0
100% fluxes
100% costs
0
20
40
60
80
100

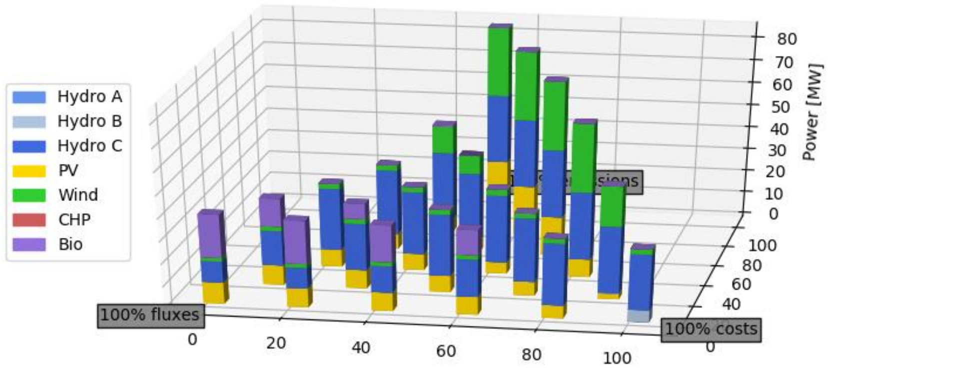

Additional generation for area A8 with weighted sum method - Unbounded scenario, free el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
30
25
20
15
10
5
0
100
80
60
40
0
100% fluxes
100% costs
0
20
40
60
80
100


Additional generation for area A9 with weighted sum method - Unbounded scenario, free el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100
0
5
10
15
20
25
30
35

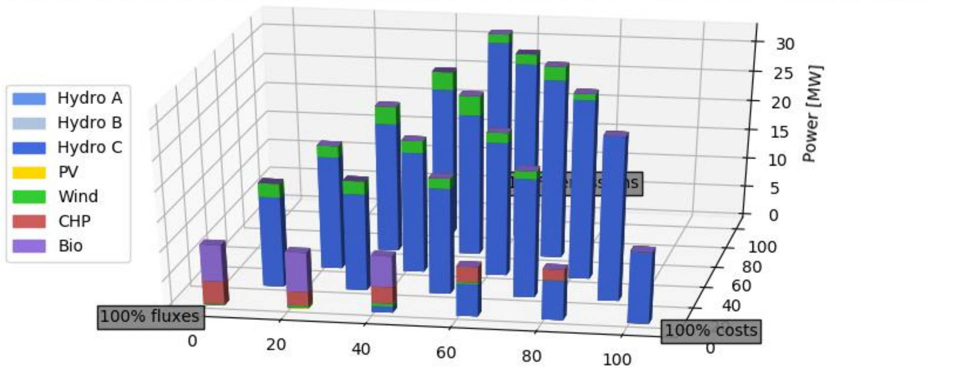

Additional generation for area A10 with weighted sum method - Unbounded scenario, free el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100
0
2
4
6
8
10
12
14


Additional generation for area A11 with weighted sum method - Unbounded scenario, free el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100
0
2
4
6
8
10

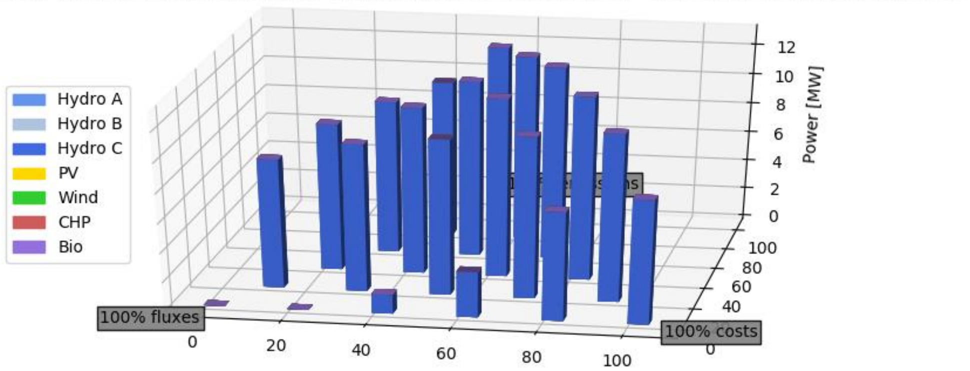
Additional generation for area A12 with weighted sum method - Unbounded scenario, free el.



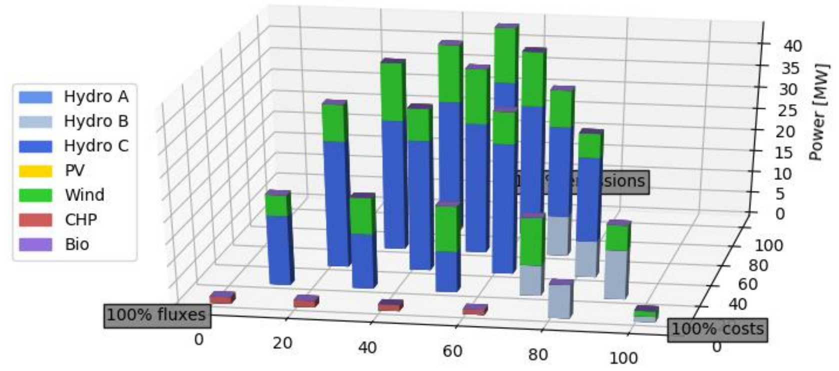
Additional generation for area A13 with weighted sum method - Unbounded scenario, free el.



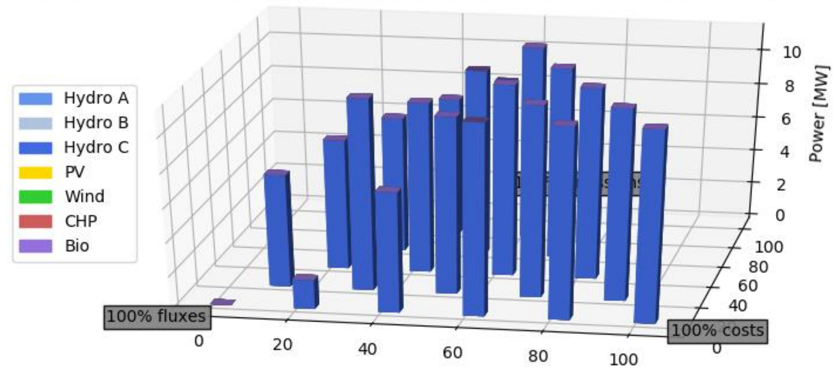
Additional generation for area A14 with weighted sum method - Unbounded scenario, free el.



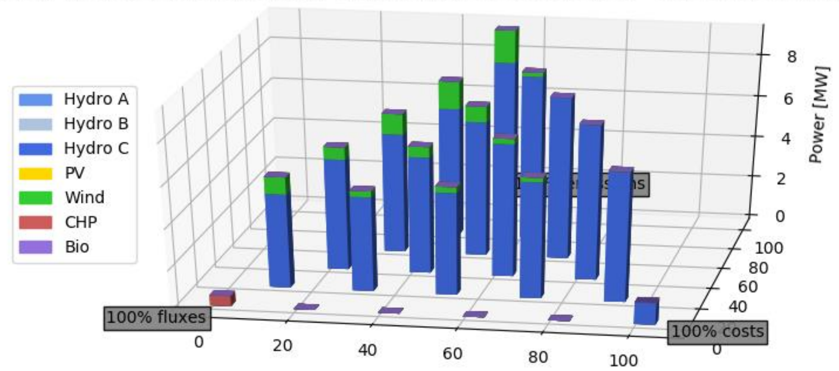
Additional generation for area A15 with weighted sum method - Unbounded scenario, free el.



Additional generation for area A16 with weighted sum method - Unbounded scenario, free el.

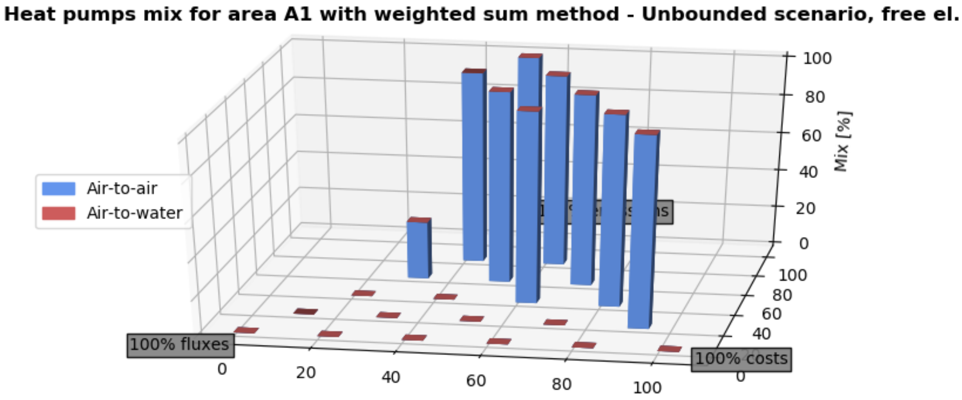


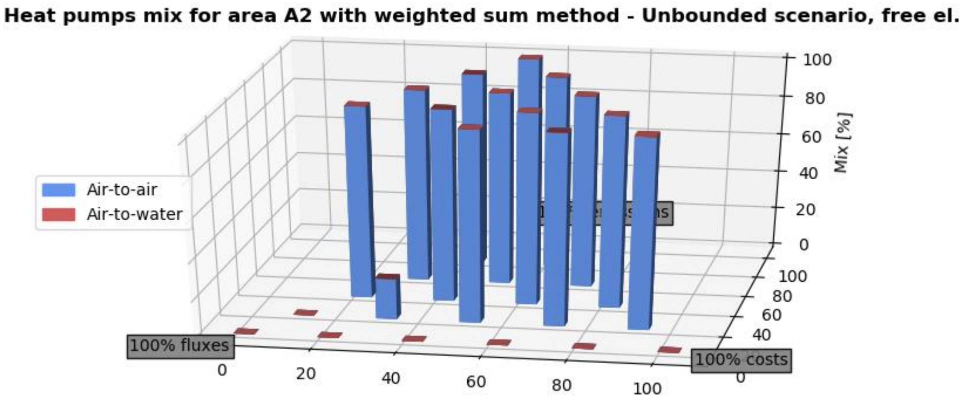
Additional generation for area A17 with weighted sum method - Unbounded scenario, free el.

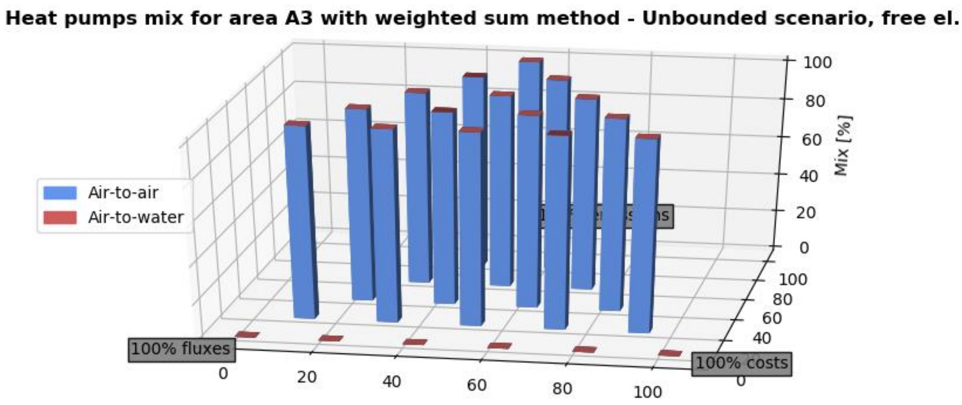


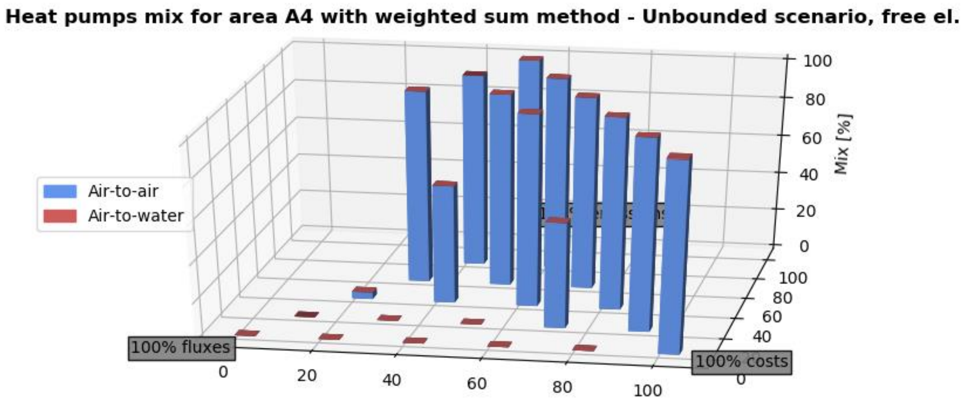
Appendix C – Electrification in unbounded potential scenario

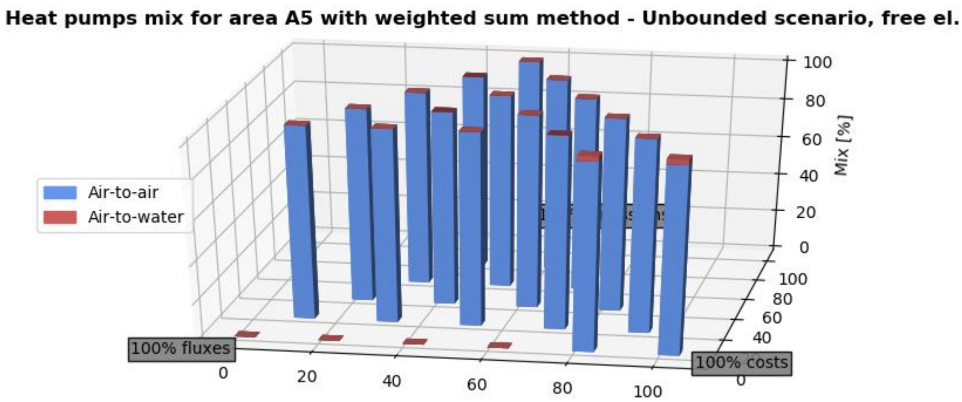
This appendix reports the results of the optimization with weighted sum methodology regarding the optimal electrification in the "unbounded potential" scenario.



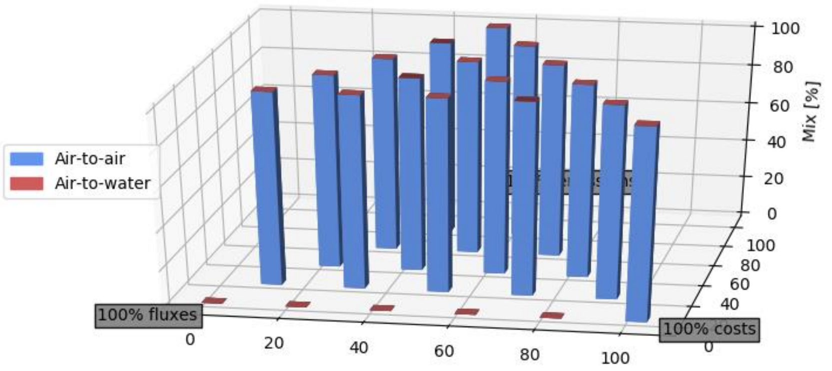



Heat pumps mix for area A3 with weighted sum method - Unbounded scenario, free el.
Air-to-air
Air-to-water
100% fluxes
100% costs
Mix [%]
0
20
40
60
80
100

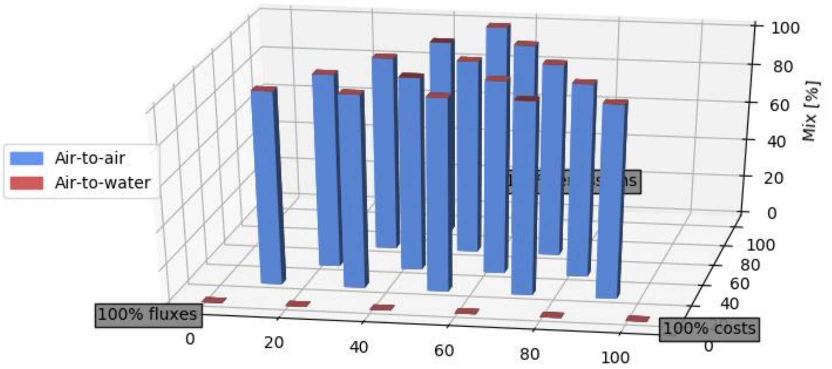

Heat pumps mix for area A4 with weighted sum method - Unbounded scenario, free el.
Air-to-air
Air-to-water
100% fluxes
100% costs
Mix [%]
0
20
40
60
80
100


Heat pumps mix for area A5 with weighted sum method - Unbounded scenario, free el.
Air-to-air
Air-to-water
100% fluxes
100% costs
Mix [%]
0
20
40
60
80
100

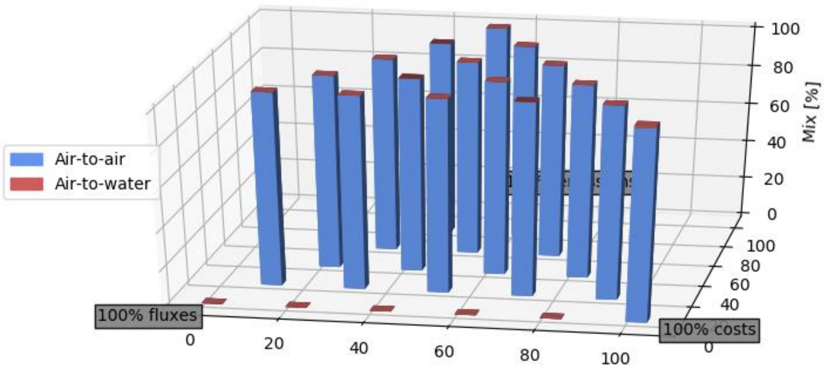
Heat pumps mix for area A6 with weighted sum method - Unbounded scenario, free el.



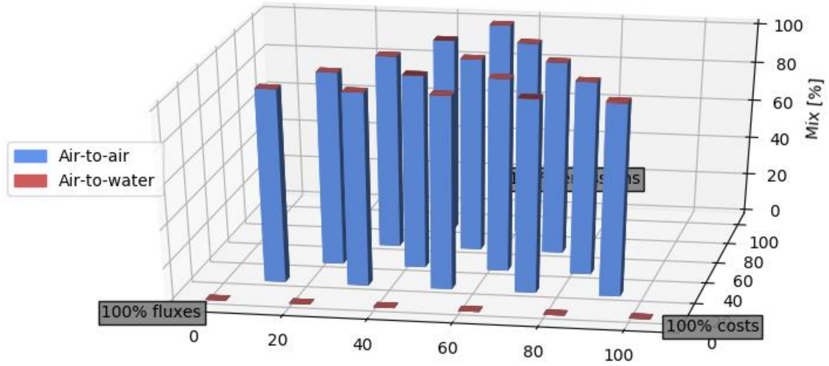
Heat pumps mix for area A7 with weighted sum method - Unbounded scenario, free el.



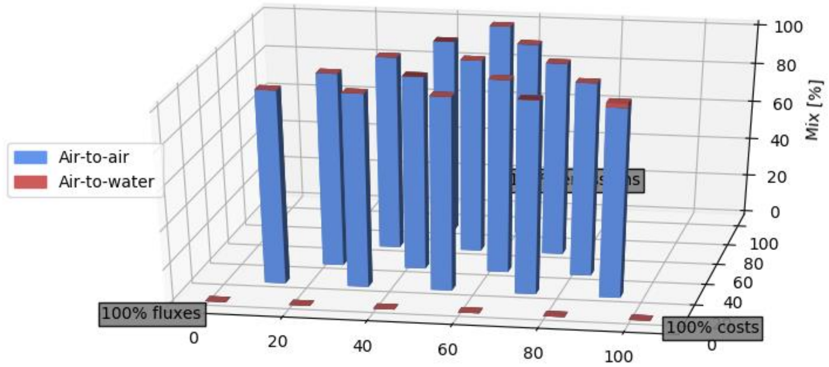
Heat pumps mix for area A8 with weighted sum method - Unbounded scenario, free el.



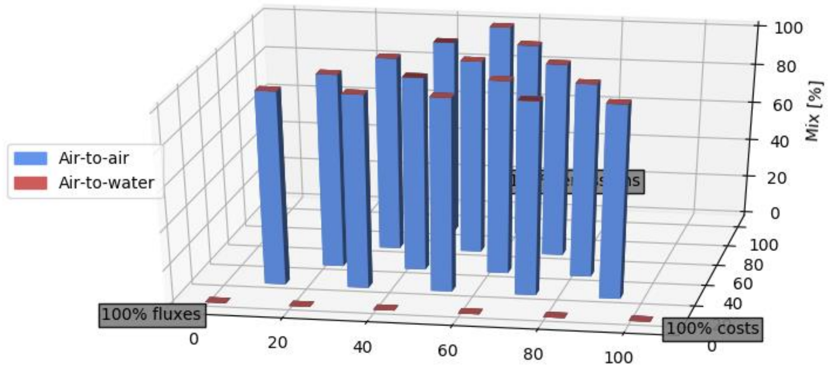
Heat pumps mix for area A9 with weighted sum method - Unbounded scenario, free el.



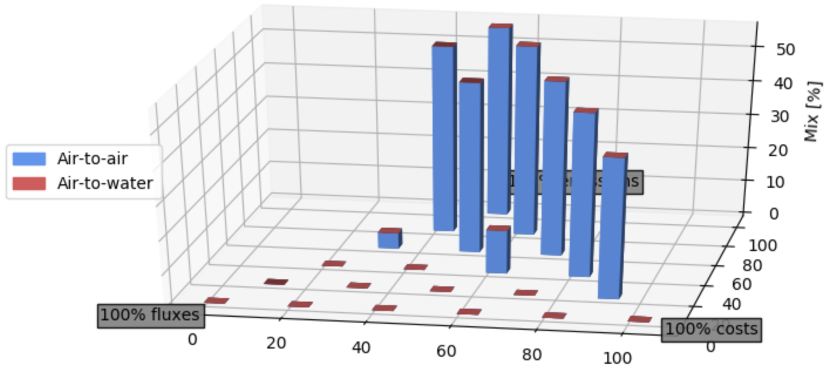
Heat pumps mix for area A10 with weighted sum method - Unbounded scenario, free el.



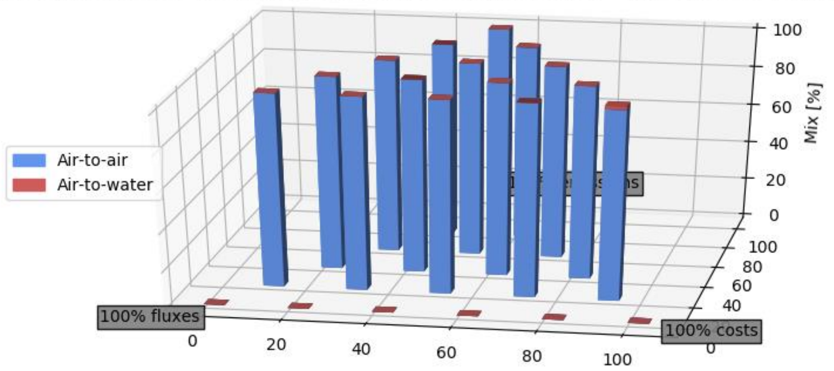
Heat pumps mix for area A11 with weighted sum method - Unbounded scenario, free el.



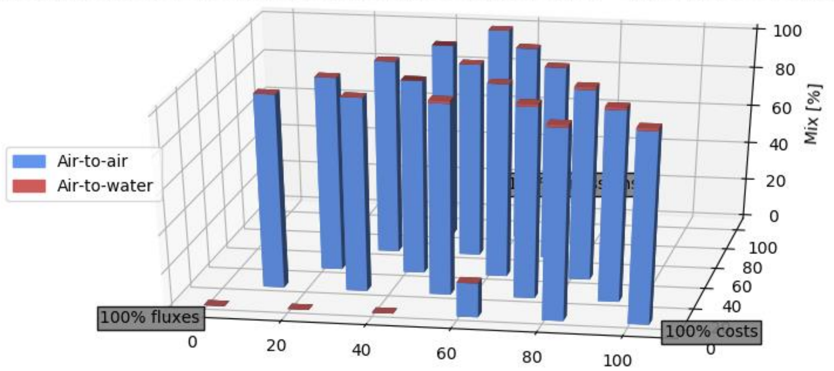
Heat pumps mix for area A12 with weighted sum method - Unbounded scenario, free el.

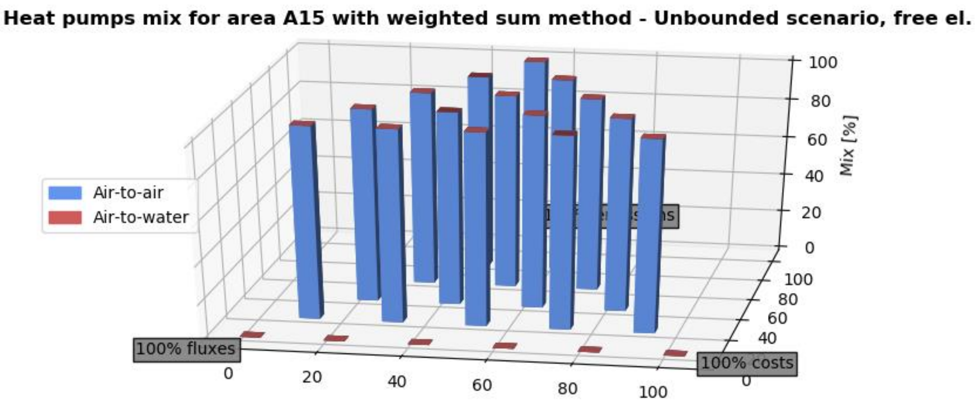


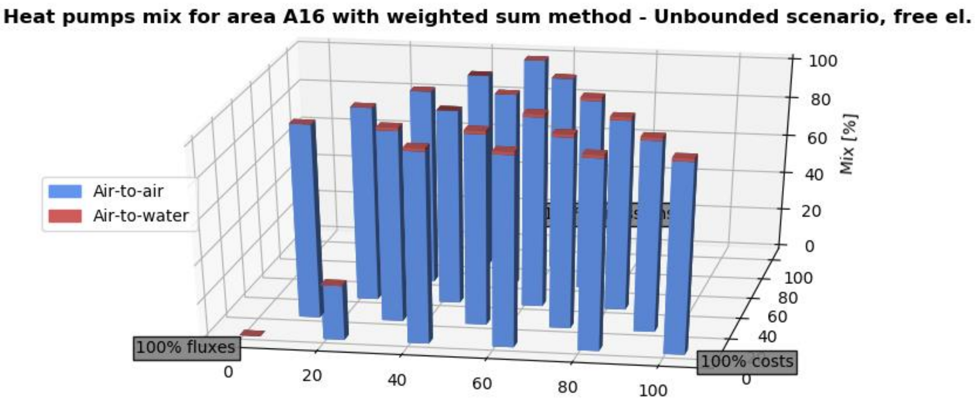
Heat pumps mix for area A13 with weighted sum method - Unbounded scenario, free el.

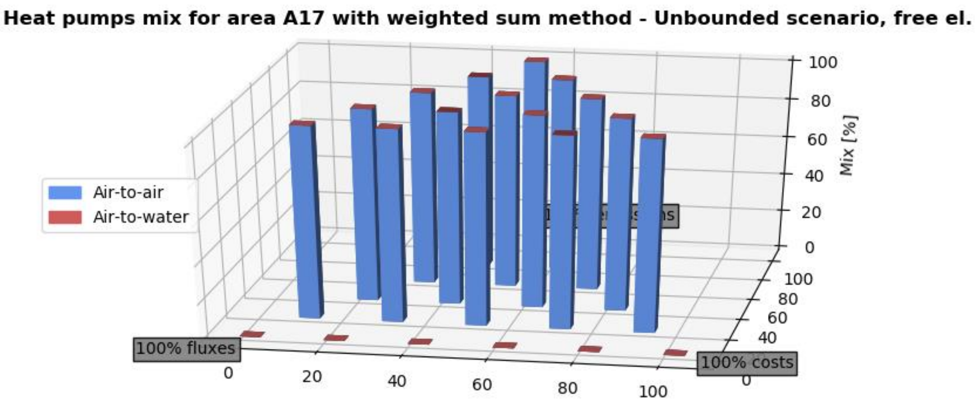


Heat pumps mix for area A14 with weighted sum method - Unbounded scenario, free el.



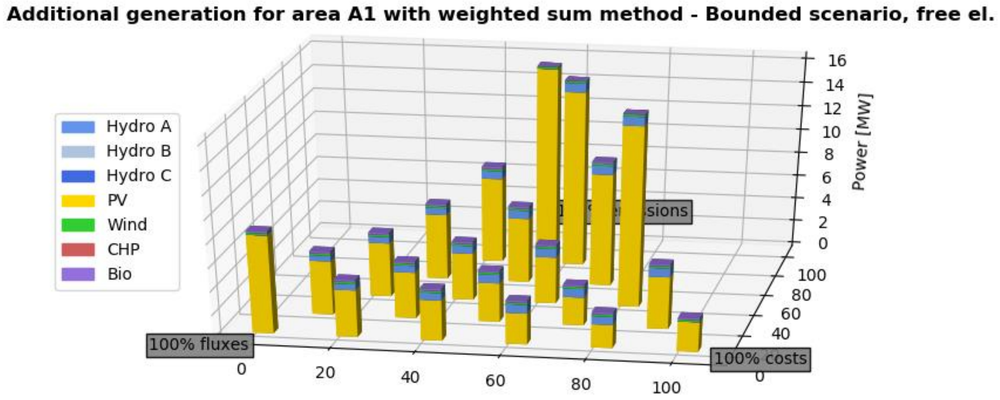

Heat pumps mix for area A15 with weighted sum method - Unbounded scenario, free el.
Air-to-air
Air-to-water
Mix [%]
100% fluxes
100% costs
0
20
40
60
80
100

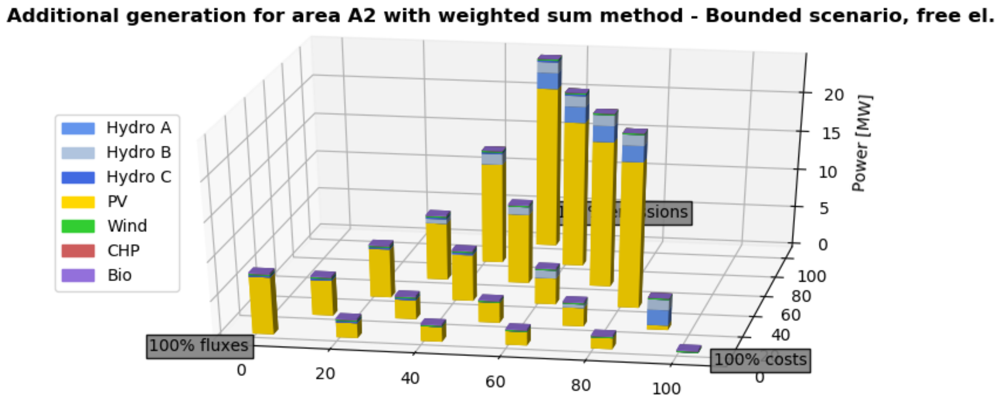

Heat pumps mix for area A16 with weighted sum method - Unbounded scenario, free el.
Air-to-air
Air-to-water
Mix [%]
100% fluxes
100% costs
0
20
40
60
80
100


Heat pumps mix for area A17 with weighted sum method - Unbounded scenario, free el.
Air-to-air
Air-to-water
Mix [%]
100% fluxes
100% costs
0
20
40
60
80
100

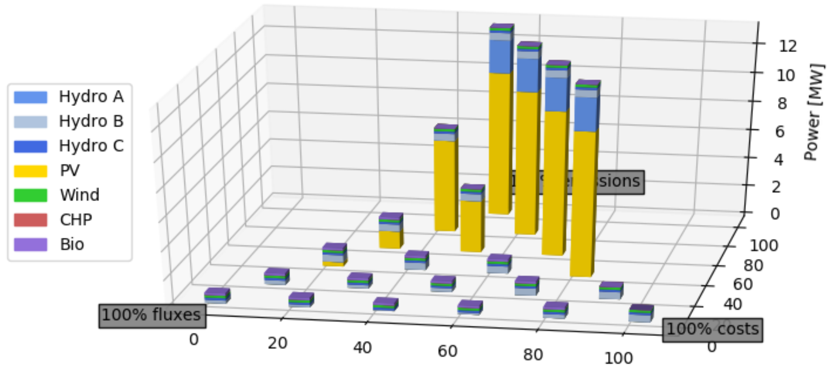
Appendix D – Bounded potential generation with free electrification

This appendix reports the results of the optimization with weighted sum methodology regarding the "bounded potential" additional generation in the free electrification scenario.

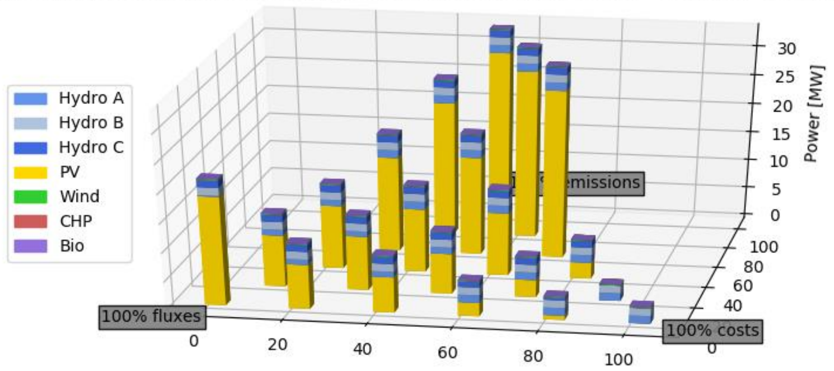




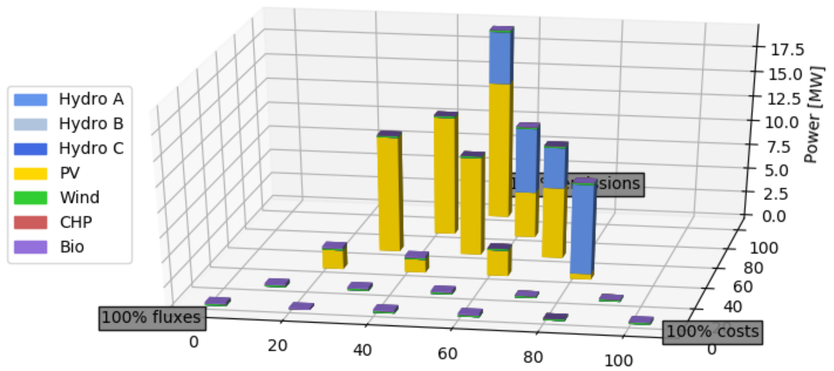
Additional generation for area A3 with weighted sum method - Bounded scenario, free el.



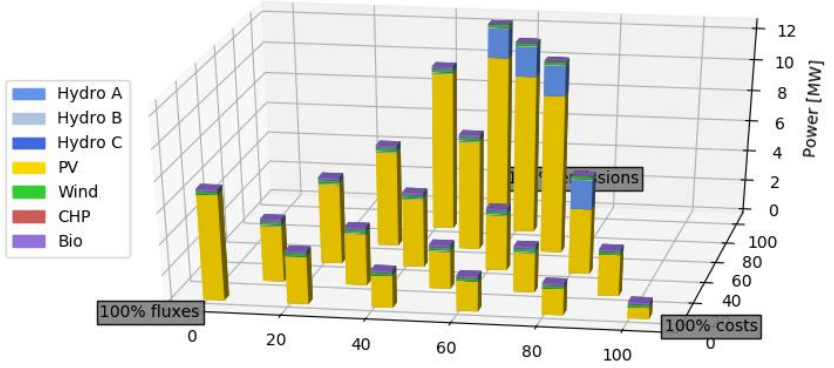
Additional generation for area A4 with weighted sum method - Bounded scenario, free el.



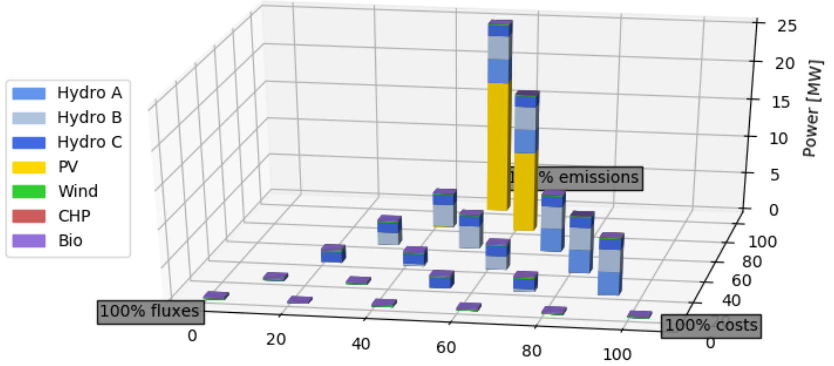
Additional generation for area A5 with weighted sum method - Bounded scenario, free el.



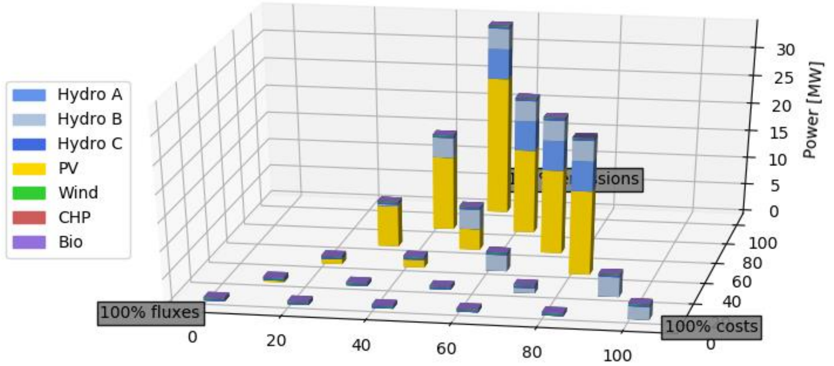
Additional generation for area A6 with weighted sum method - Bounded scenario, free el.



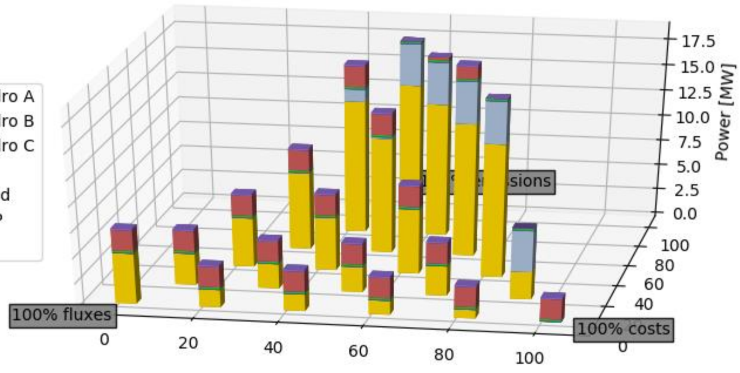
Additional generation for area A7 with weighted sum method - Bounded scenario, free el.



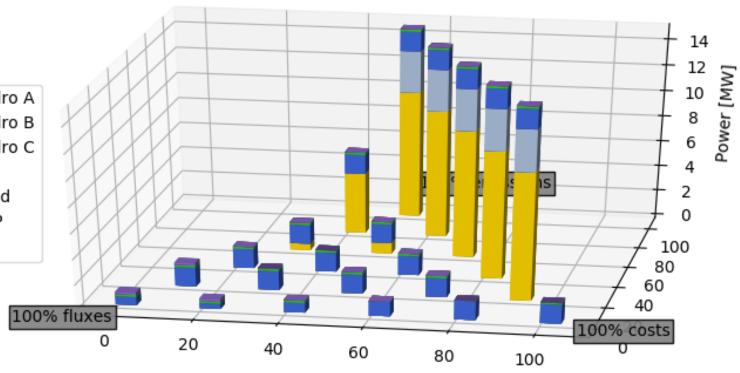
Additional generation for area A8 with weighted sum method - Bounded scenario, free el.



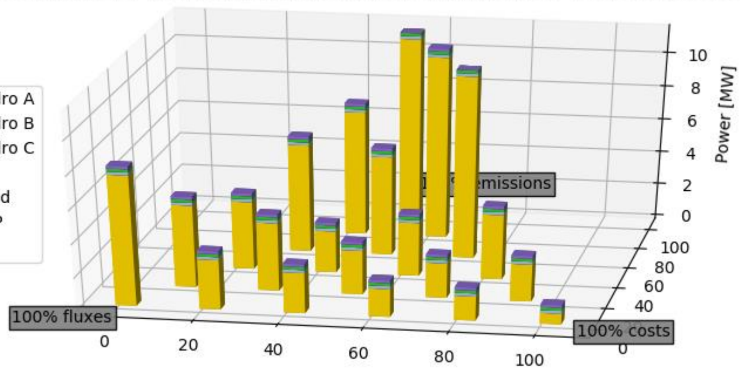
Additional generation for area A9 with weighted sum method - Bounded scenario, free el.



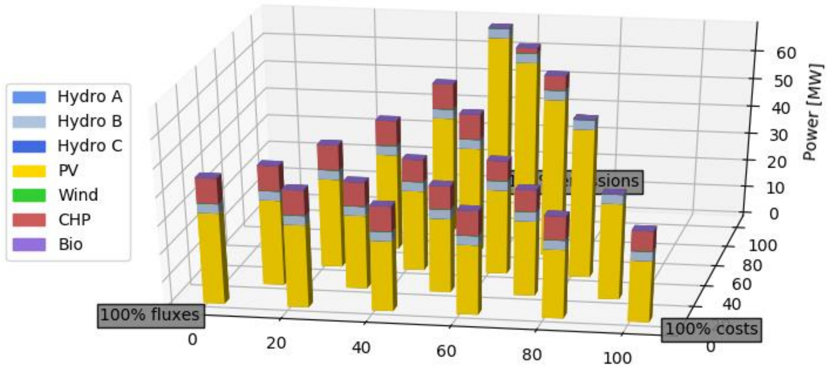
Additional generation for area A10 with weighted sum method - Bounded scenario, free el.



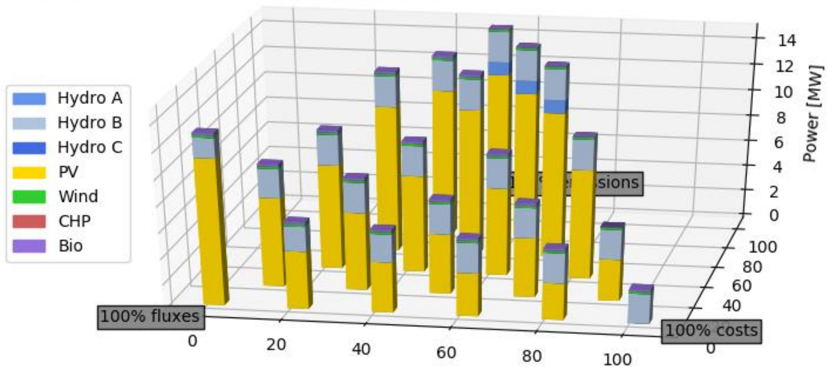
Additional generation for area A11 with weighted sum method - Bounded scenario, free el.



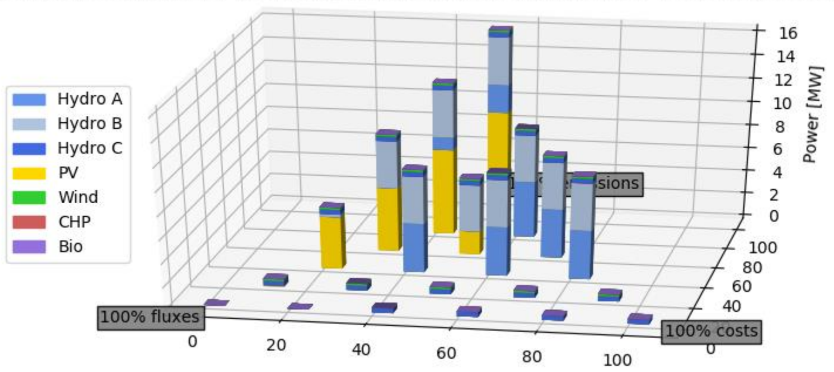
Additional generation for area A12 with weighted sum method - Bounded scenario, free el.



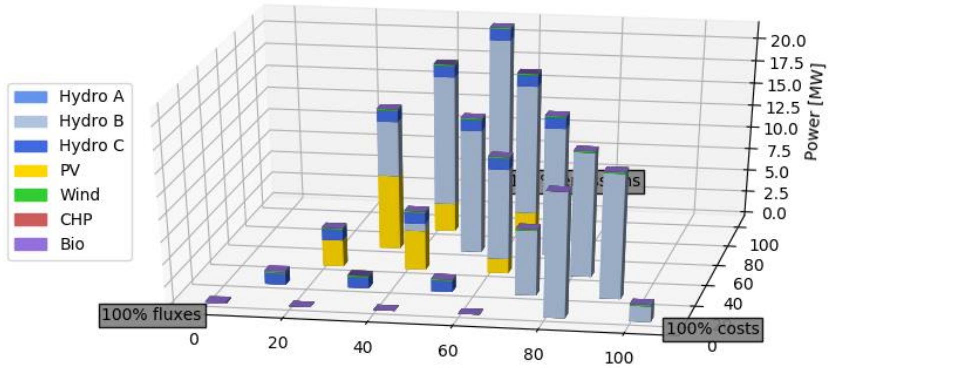
Additional generation for area A13 with weighted sum method - Bounded scenario, free el.



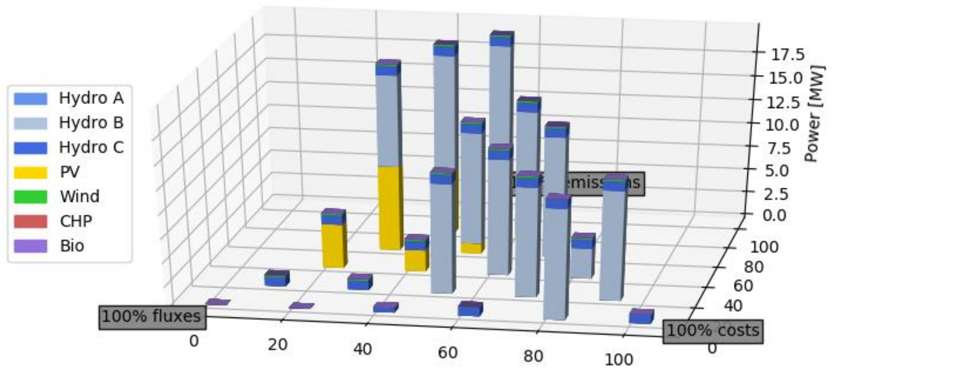
Additional generation for area A14 with weighted sum method - Bounded scenario, free el.



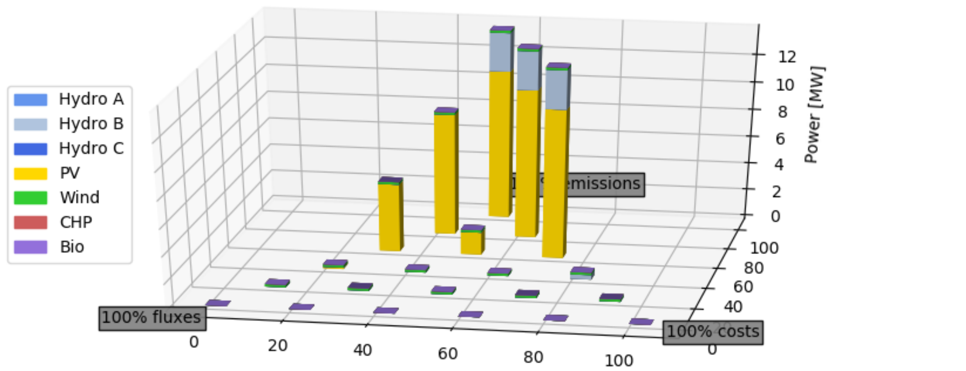
Additional generation for area A15 with weighted sum method - Bounded scenario, free el.



Additional generation for area A16 with weighted sum method - Bounded scenario, free el.

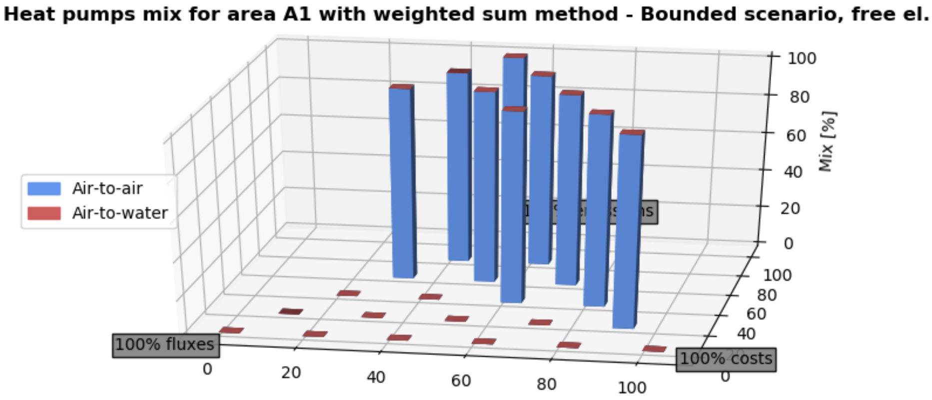


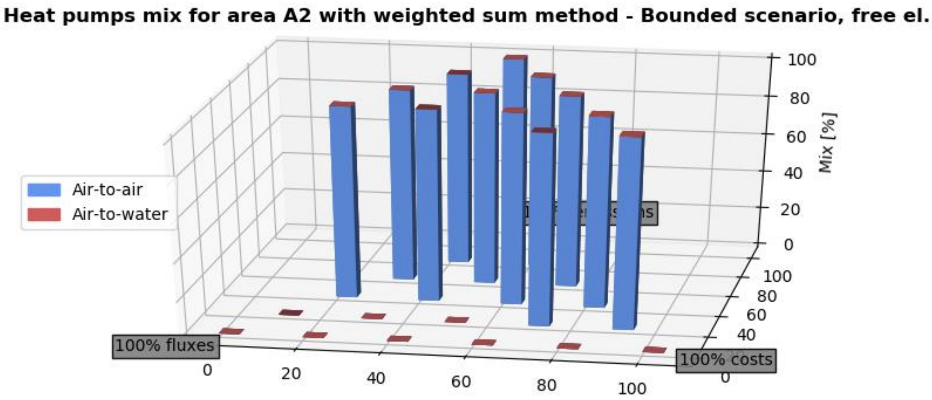
Additional generation for area A17 with weighted sum method - Bounded scenario, free el.

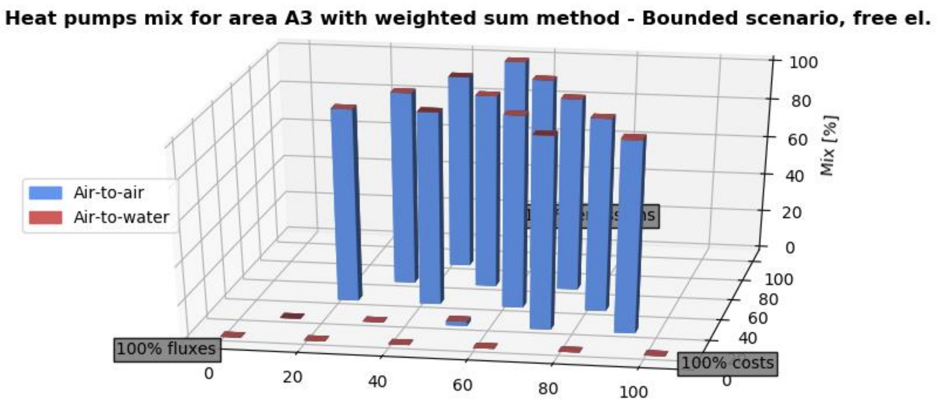


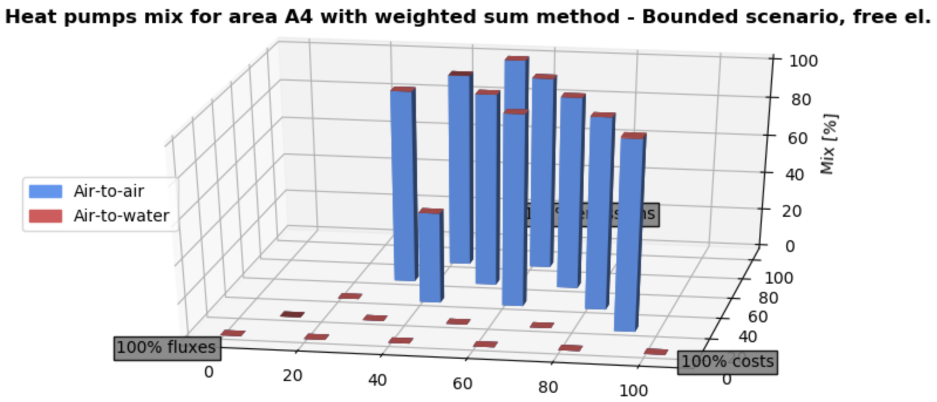
Appendix E – Electrification in bounded potential scenario with free electrification

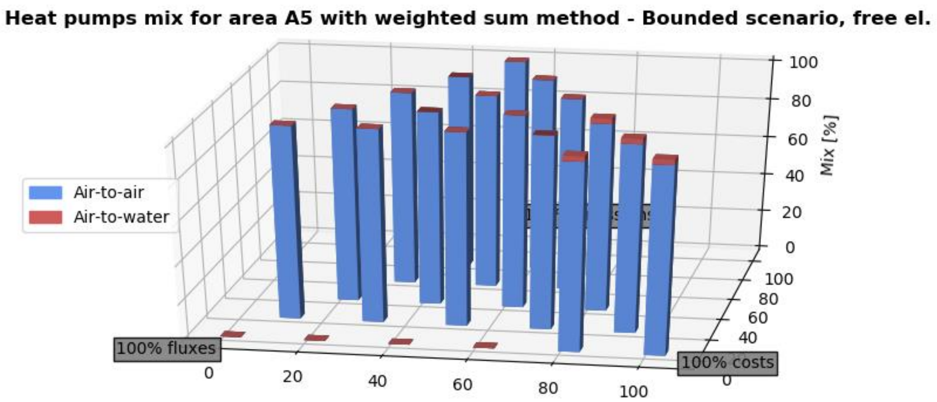
This appendix reports the results of the optimization with weighted sum methodology regarding the optimal electrification in the "bounded potential" scenario.



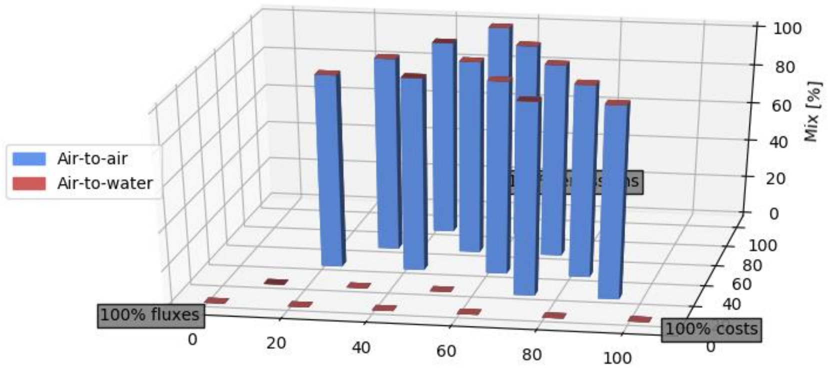



Heat pumps mix for area A3 with weighted sum method - Bounded scenario, free el.
Air-to-air
Air-to-water
100% fluxes
100% costs
Mix [%]
0
20
40
60
80
100

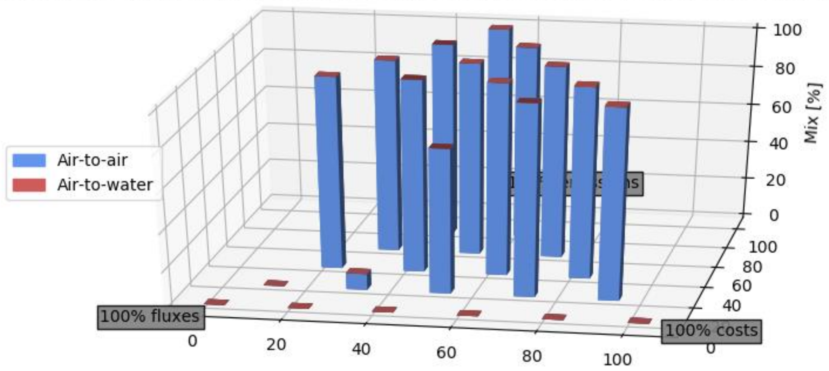

Heat pumps mix for area A4 with weighted sum method - Bounded scenario, free el.
Air-to-air
Air-to-water
100% fluxes
100% costs
Mix [%]
0
20
40
60
80
100


Heat pumps mix for area A5 with weighted sum method - Bounded scenario, free el.
Air-to-air
Air-to-water
100% fluxes
100% costs
Mix [%]
0
20
40
60
80
100

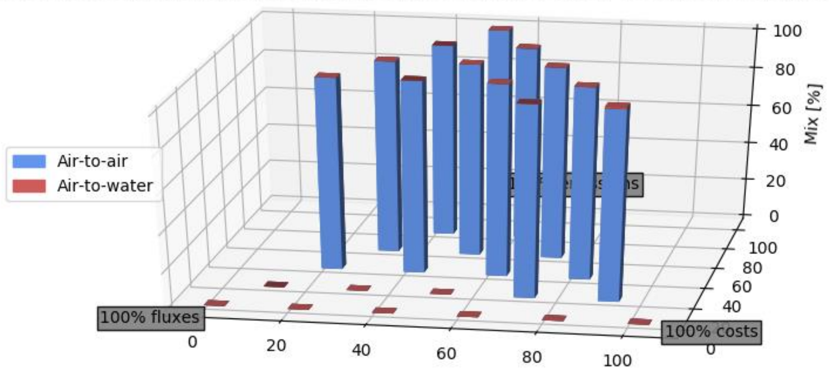
Heat pumps mix for area A6 with weighted sum method - Bounded scenario, free el.



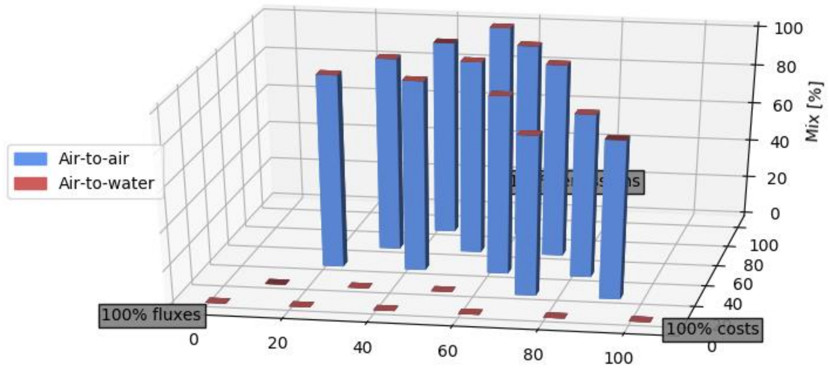
Heat pumps mix for area A7 with weighted sum method - Bounded scenario, free el.



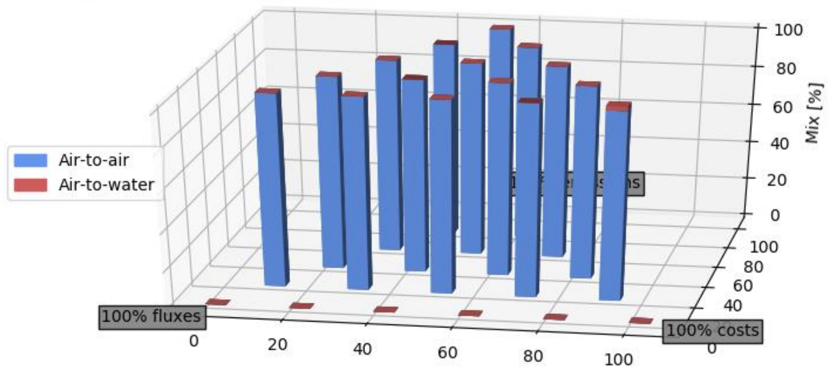
Heat pumps mix for area A8 with weighted sum method - Bounded scenario, free el.



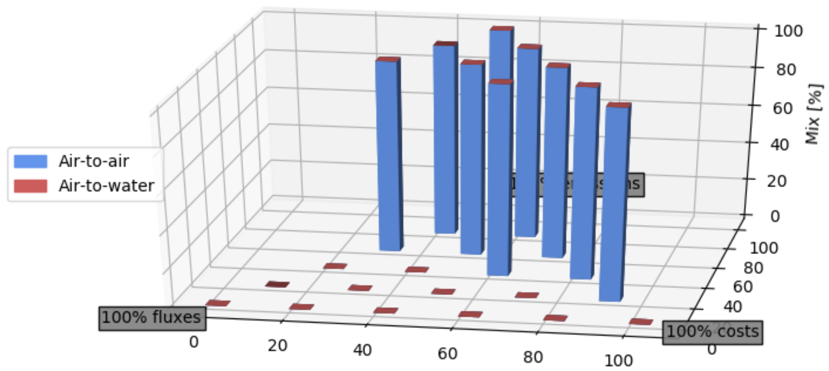
Heat pumps mix for area A9 with weighted sum method - Bounded scenario, free el.

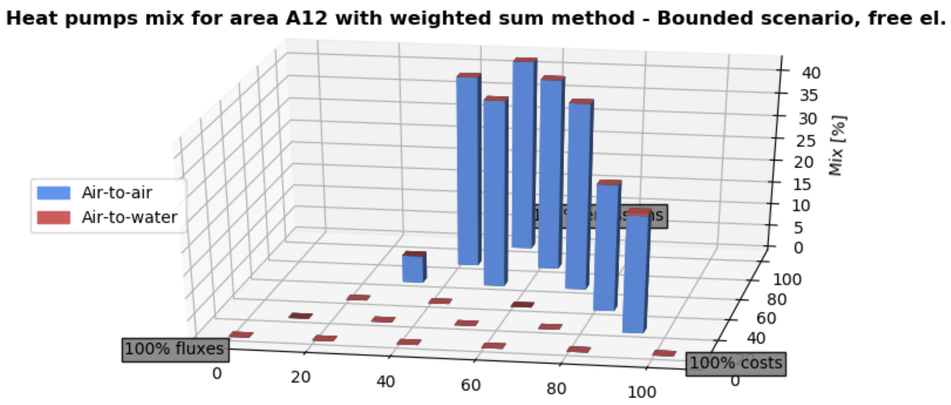


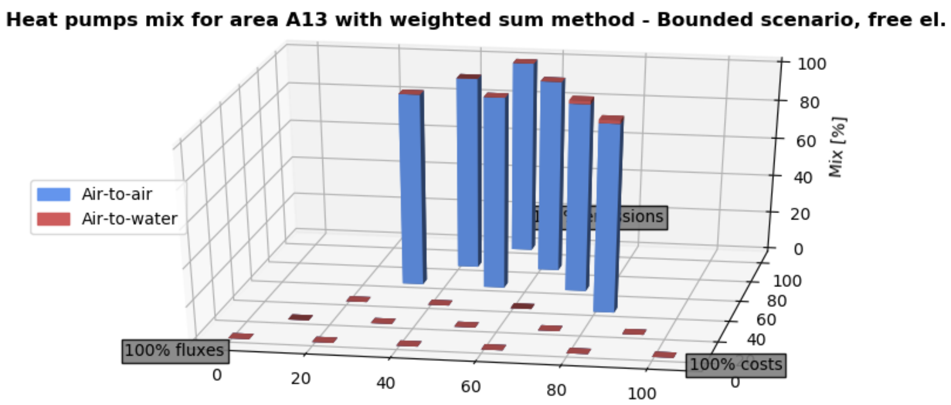
Heat pumps mix for area A10 with weighted sum method - Bounded scenario, free el.

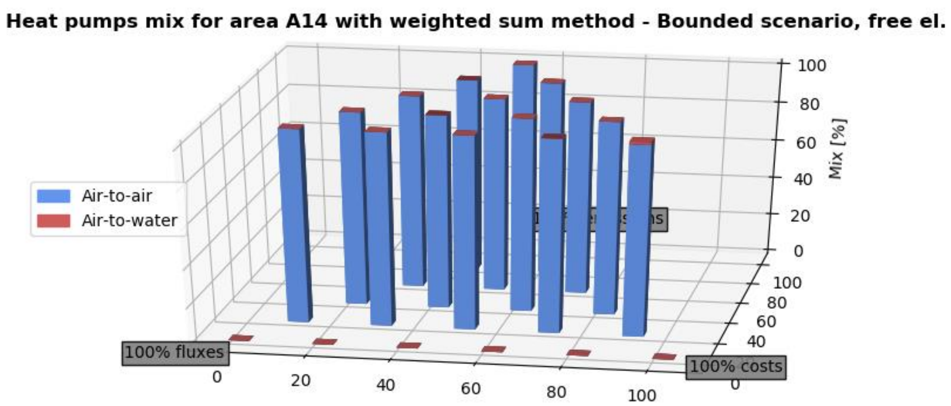


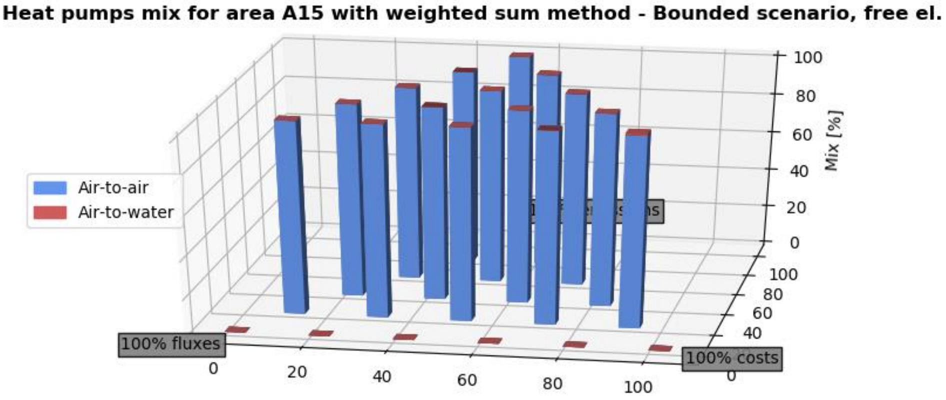
Heat pumps mix for area A11 with weighted sum method - Bounded scenario, free el.

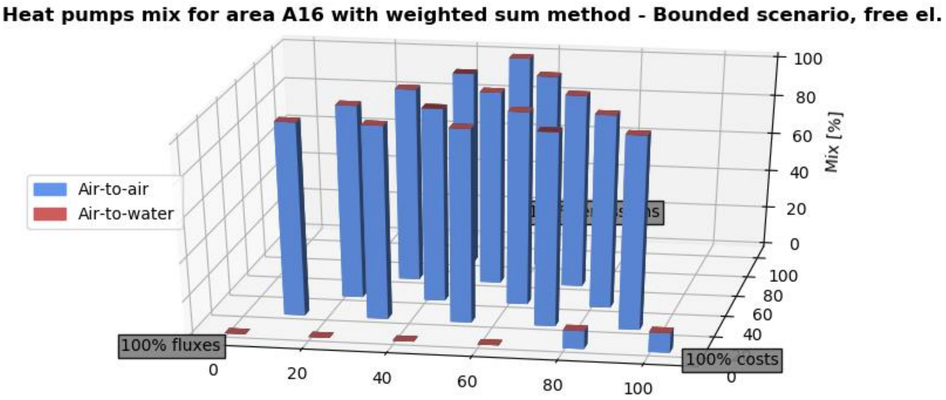


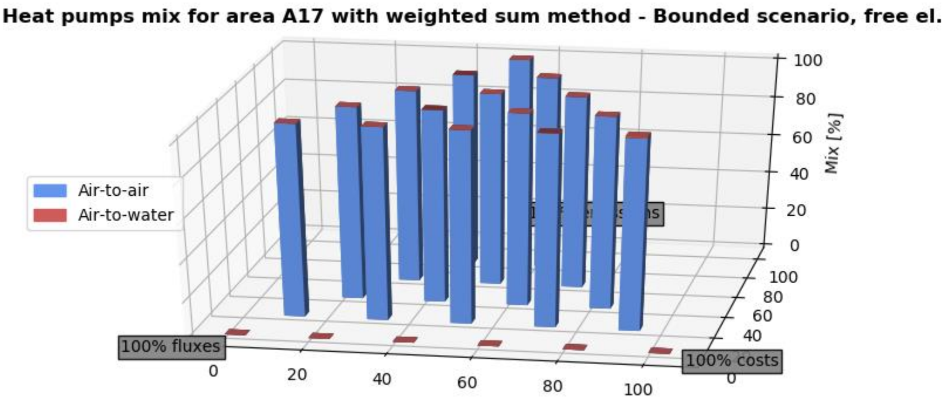

Heat pumps mix for area A12 with weighted sum method - Bounded scenario, free el.
Air-to-air
Air-to-water
Mix [%]
100% fluxes
100% costs


Heat pumps mix for area A13 with weighted sum method - Bounded scenario, free el.
Air-to-air
Air-to-water
Mix [%]
100% fluxes
100% costs


Heat pumps mix for area A14 with weighted sum method - Bounded scenario, free el.
Air-to-air
Air-to-water
Mix [%]
100% fluxes
100% costs

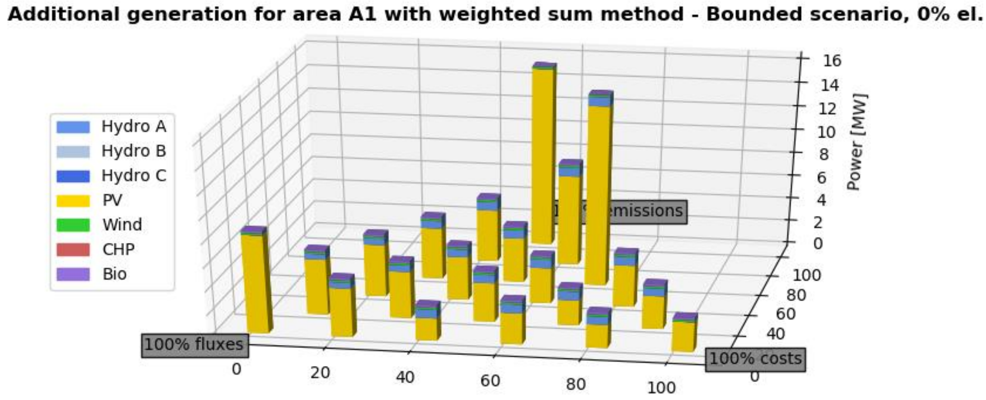

Heat pumps mix for area A15 with weighted sum method - Bounded scenario, free el.
Air-to-air
Air-to-water
Mix [%]
100% fluxes
100% costs
0
20
40
60
80
100

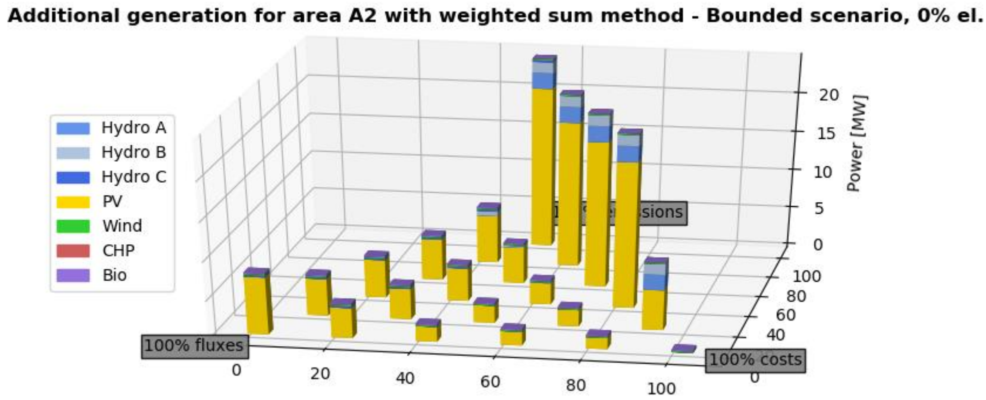

Heat pumps mix for area A16 with weighted sum method - Bounded scenario, free el.
Air-to-air
Air-to-water
Mix [%]
100% fluxes
100% costs
0
20
40
60
80
100


Heat pumps mix for area A17 with weighted sum method - Bounded scenario, free el.
Air-to-air
Air-to-water
Mix [%]
100% fluxes
100% costs
0
20
40
60
80
100

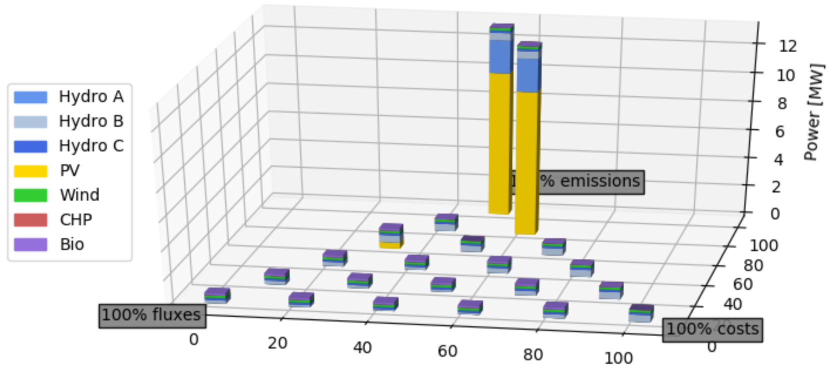
Appendix F – Bounded potential generation with 0% electrification

This appendix reports the results of the optimization with weighted sum methodology regarding the "bounded potential" additional generation in the 0% electrification scenario.

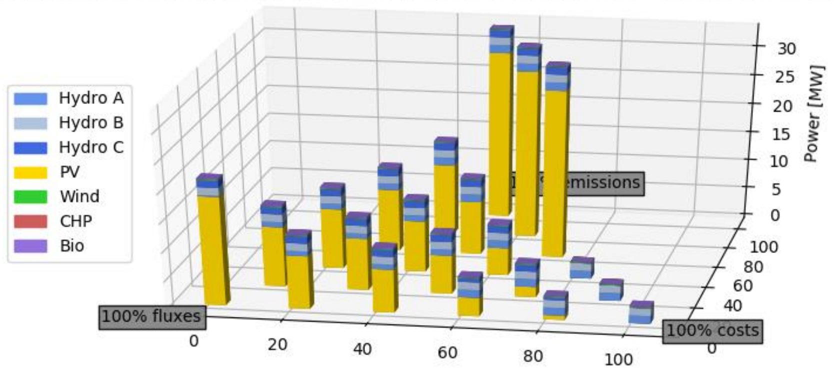




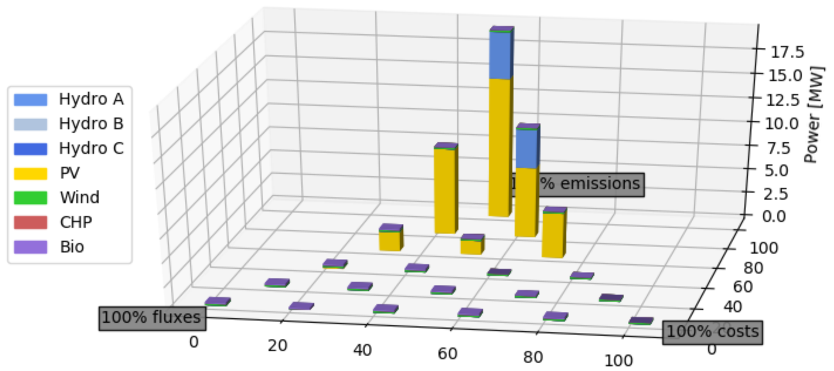
Additional generation for area A3 with weighted sum method - Bounded scenario, 0% el.



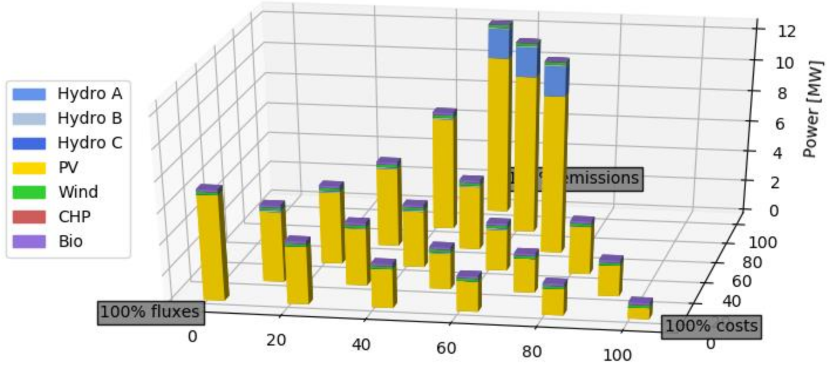
Additional generation for area A4 with weighted sum method - Bounded scenario, 0% el.



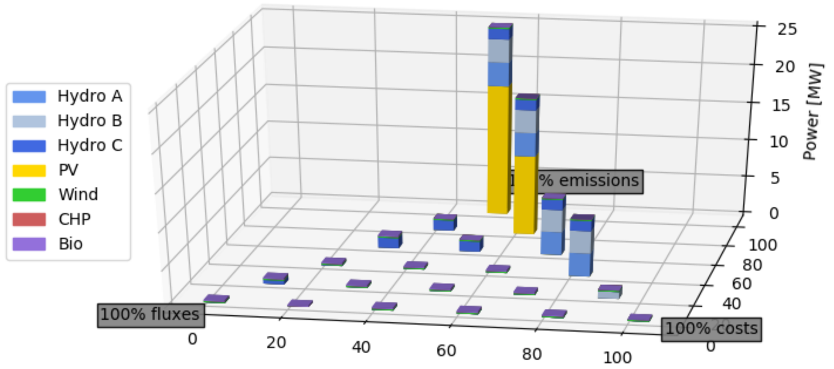
Additional generation for area A5 with weighted sum method - Bounded scenario, 0% el.



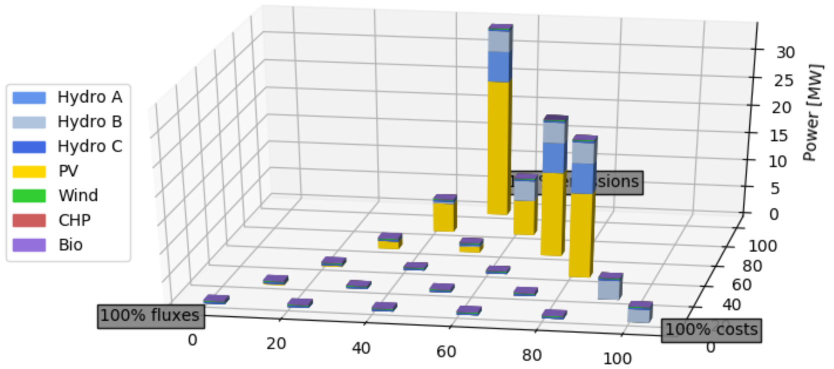
Additional generation for area A6 with weighted sum method - Bounded scenario, 0% el.



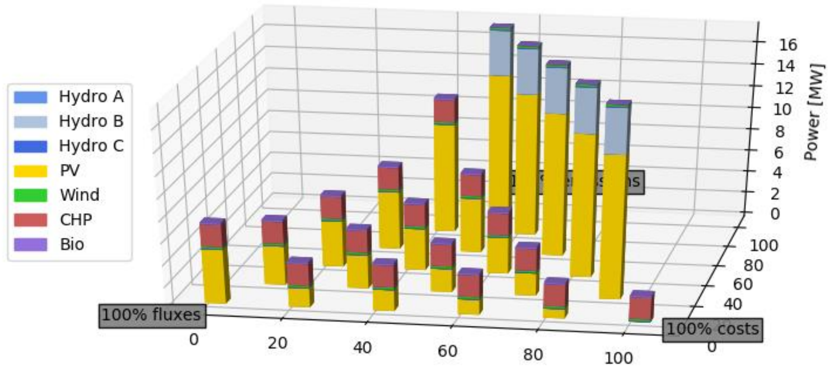
Additional generation for area A7 with weighted sum method - Bounded scenario, 0% el.



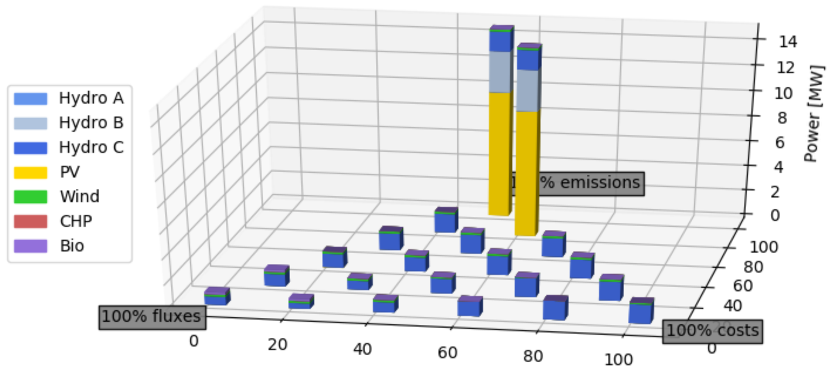
Additional generation for area A8 with weighted sum method - Bounded scenario, 0% el.



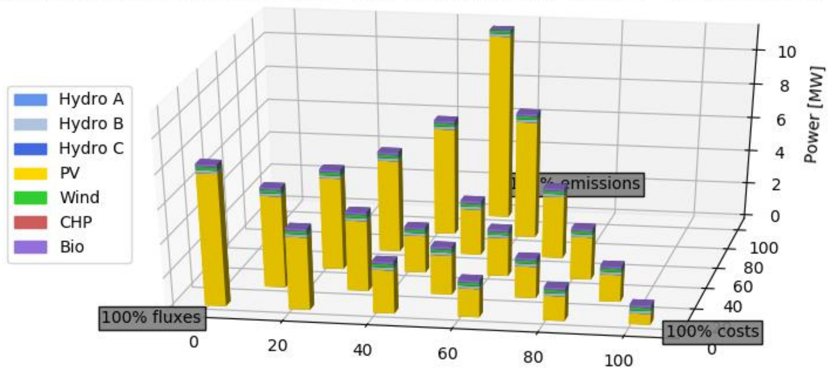
Additional generation for area A9 with weighted sum method - Bounded scenario, 0% el.



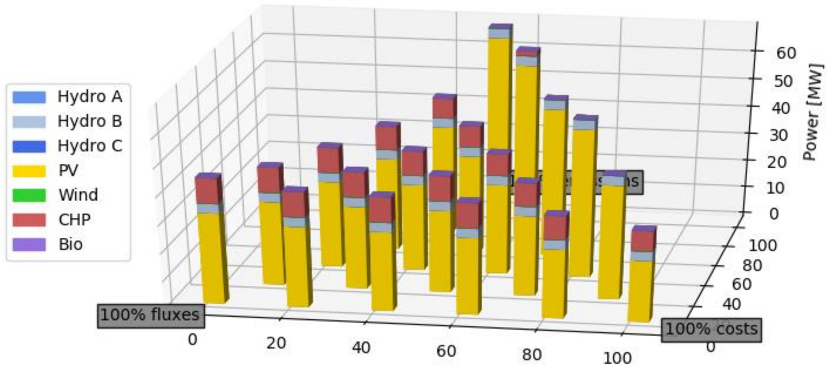
Additional generation for area A10 with weighted sum method - Bounded scenario, 0% el.



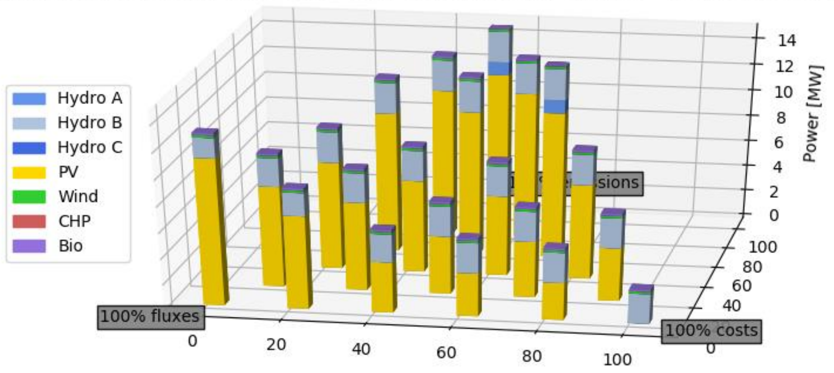
Additional generation for area A11 with weighted sum method - Bounded scenario, 0% el.



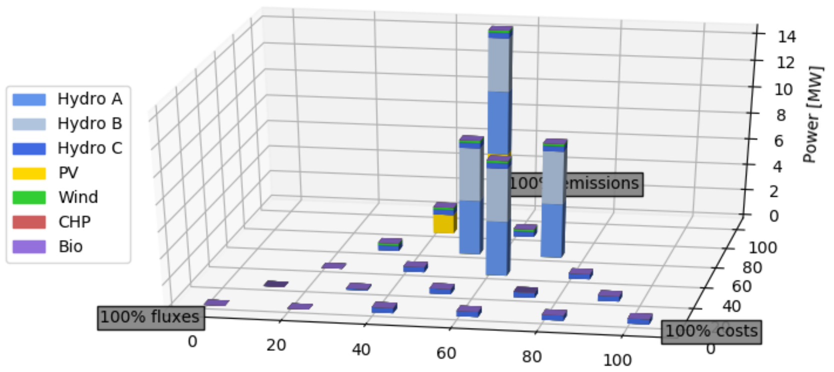
Additional generation for area A12 with weighted sum method - Bounded scenario, 0% el.

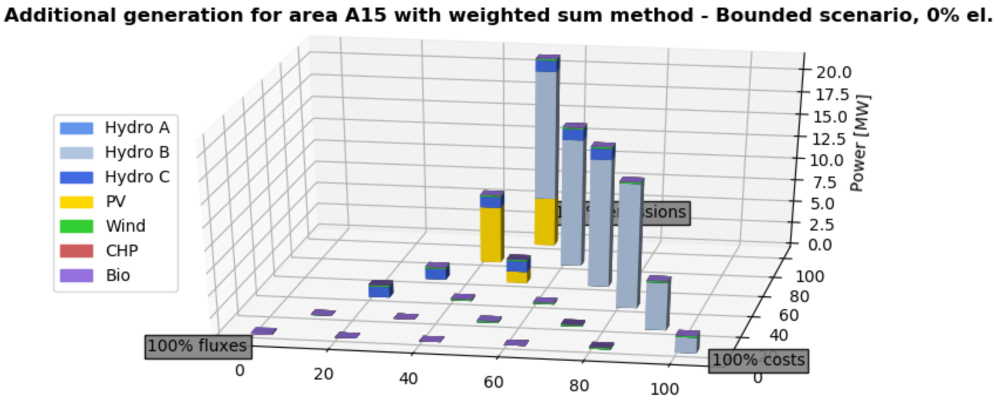


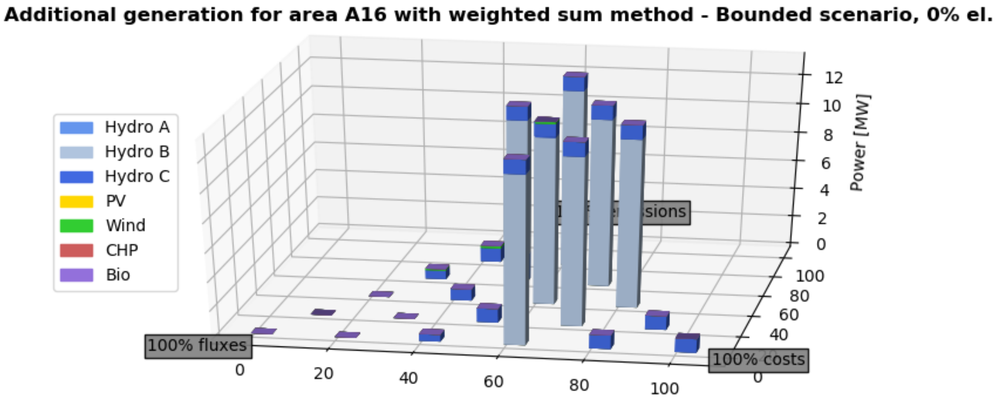
Additional generation for area A13 with weighted sum method - Bounded scenario, 0% el.

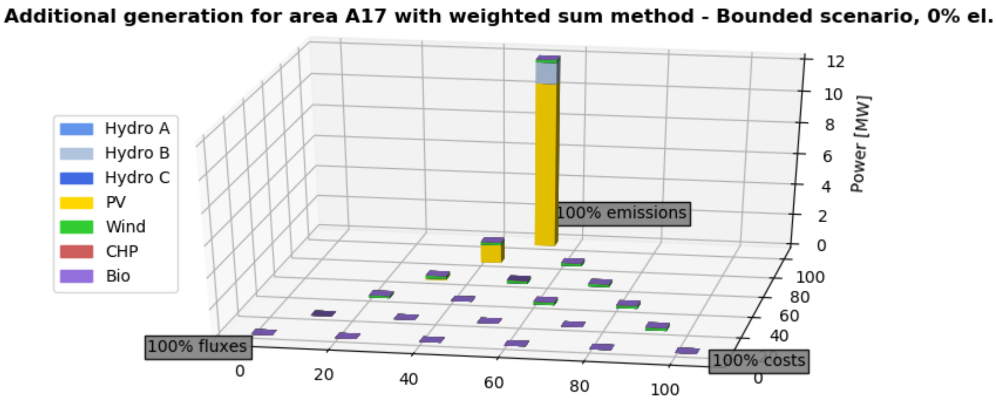


Additional generation for area A14 with weighted sum method - Bounded scenario, 0% el.



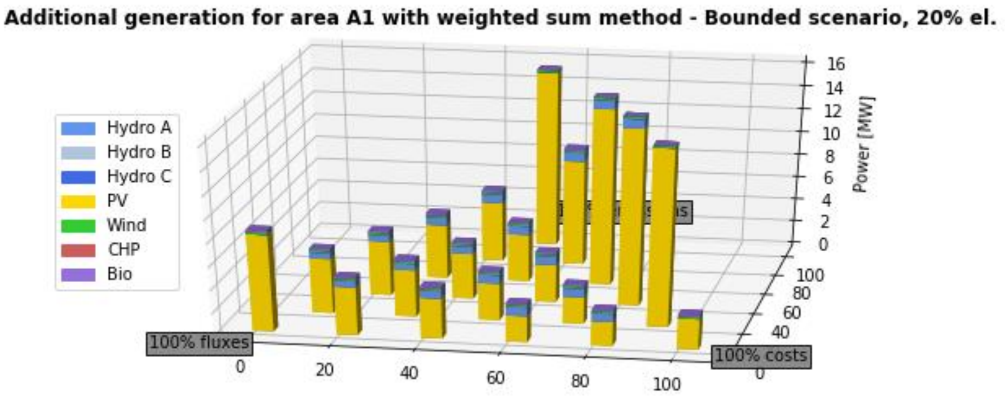

Additional generation for area A15 with weighted sum method - Bounded scenario, 0% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100
0.0
2.5
5.0
7.5
10.0
12.5
15.0
17.5
20.0

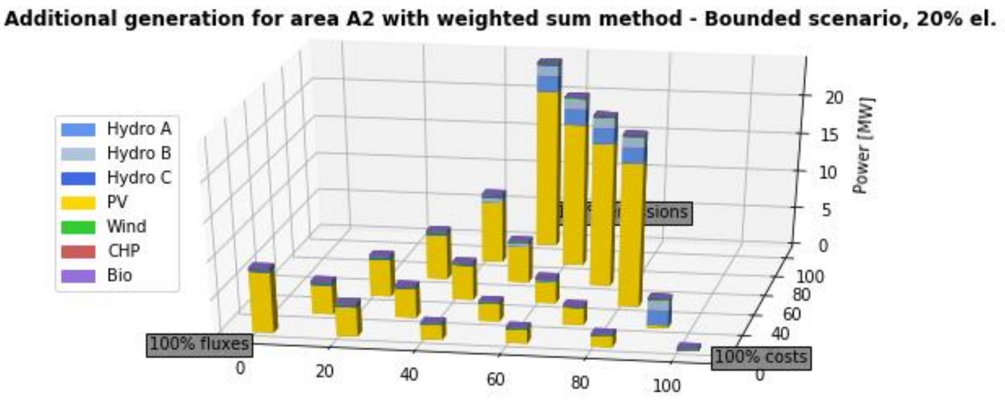

Additional generation for area A16 with weighted sum method - Bounded scenario, 0% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100
0
2
4
6
8
10
12

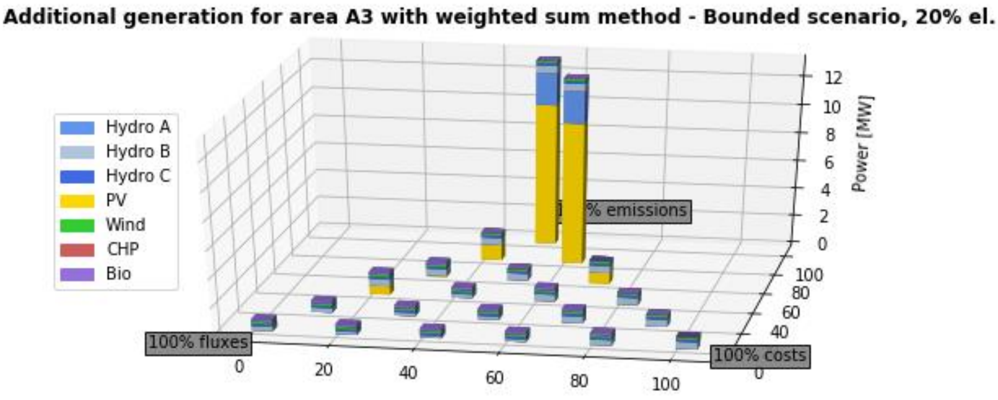

Additional generation for area A17 with weighted sum method - Bounded scenario, 0% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% emissions
100% fluxes
100% costs
0
20
40
60
80
100
0
2
4
6
8
10
12

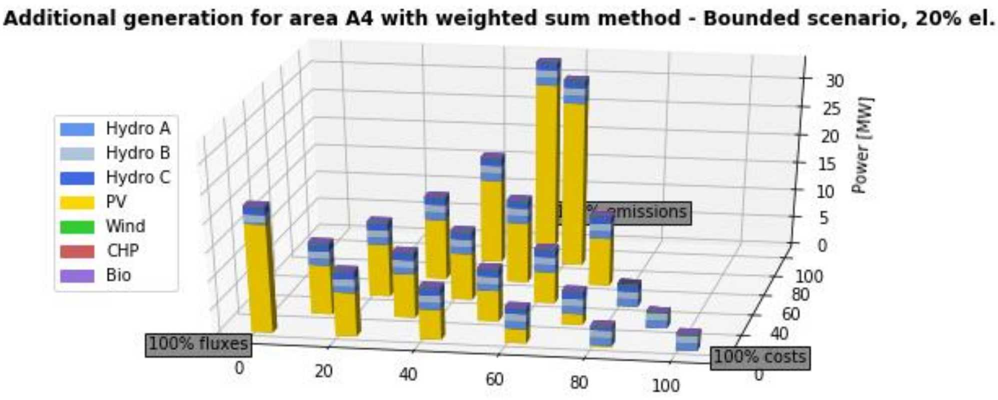
Appendix G – Bounded potential generation with 20% electrification

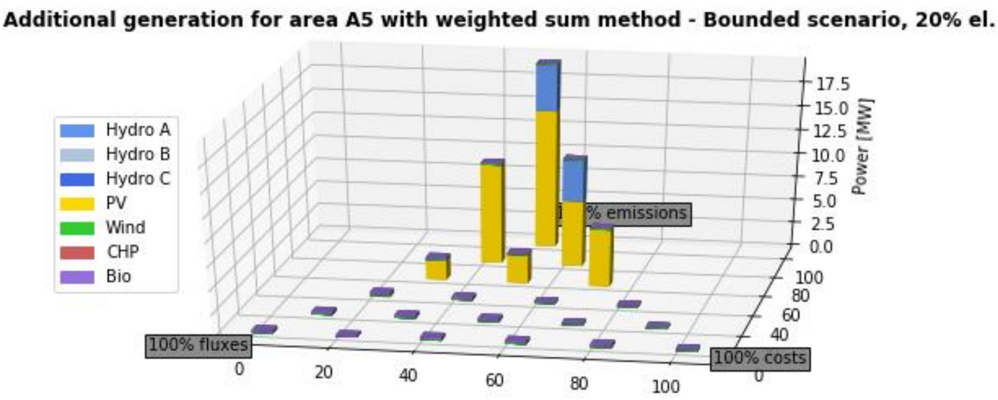
This appendix reports the results of the optimization with weighted sum methodology regarding the "bounded potential" additional generation in the 20% electrification scenario.

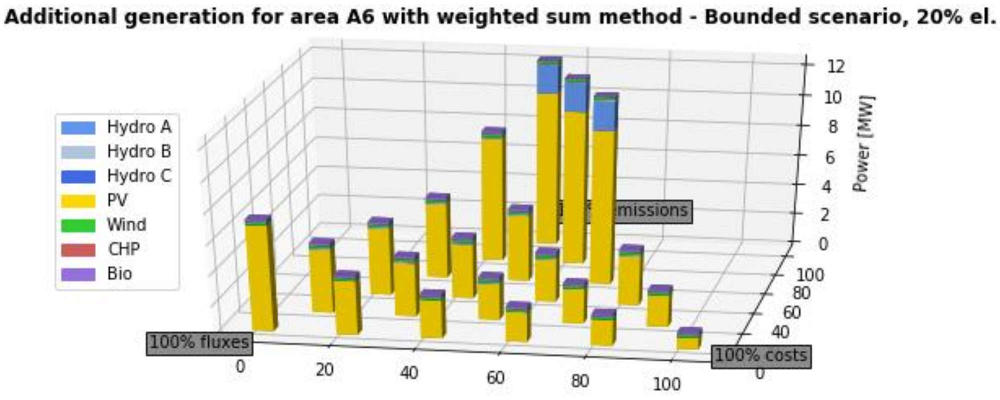


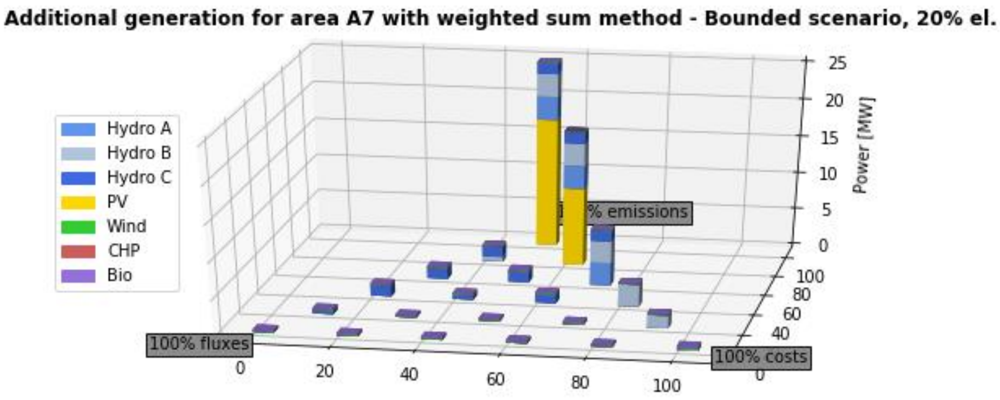


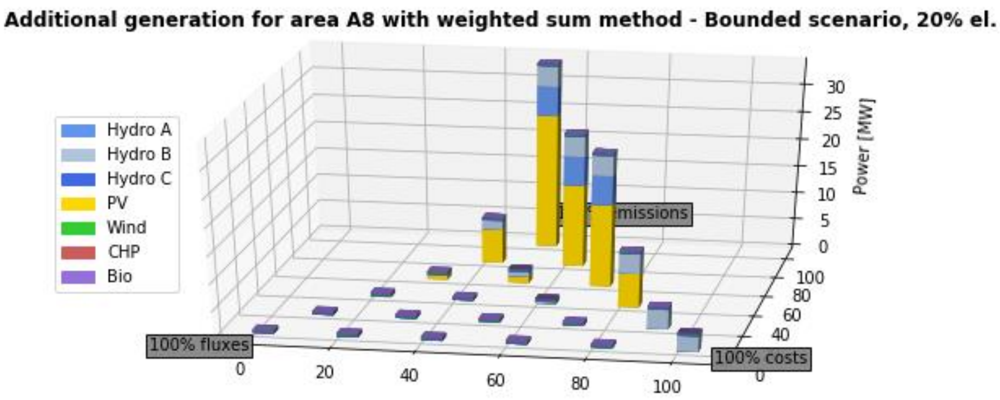

Additional generation for area A3 with weighted sum method - Bounded scenario, 20% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
% emissions

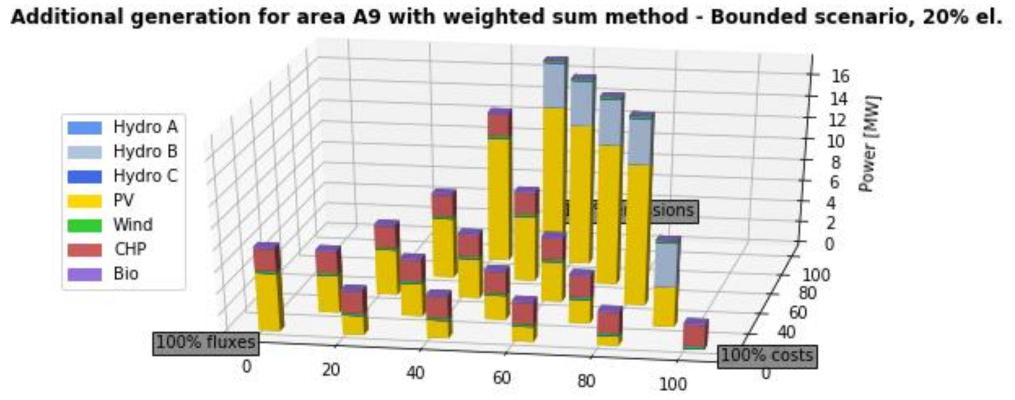

Additional generation for area A4 with weighted sum method - Bounded scenario, 20% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs

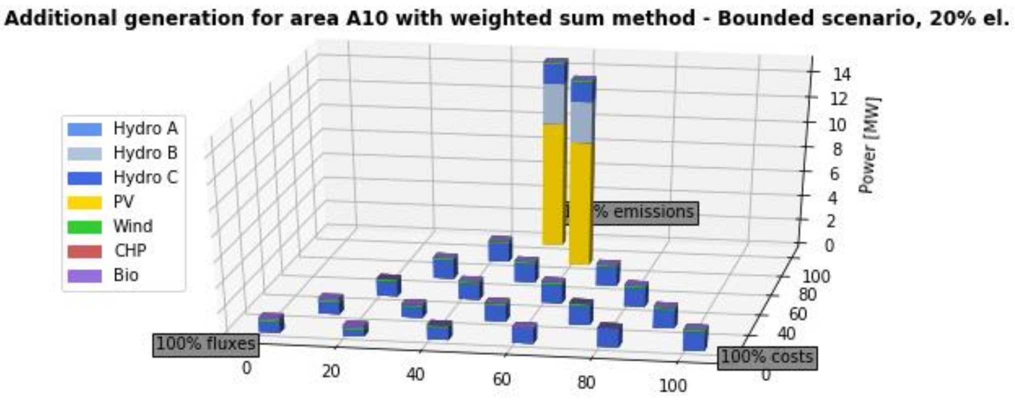

Additional generation for area A5 with weighted sum method - Bounded scenario, 20% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
% emissions

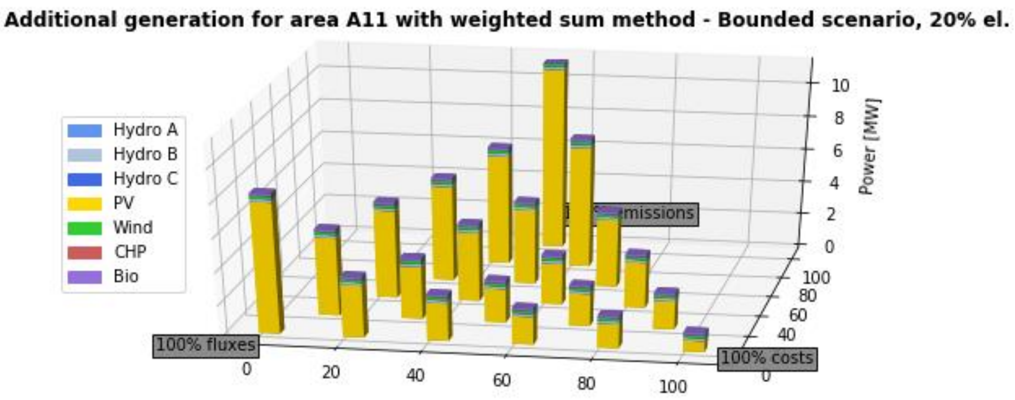

Additional generation for area A6 with weighted sum method - Bounded scenario, 20% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs


Additional generation for area A7 with weighted sum method - Bounded scenario, 20% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs

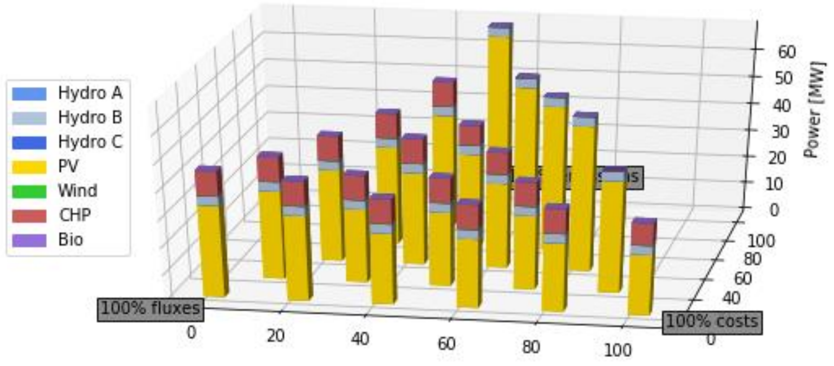

Additional generation for area A8 with weighted sum method - Bounded scenario, 20% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs


Additional generation for area A9 with weighted sum method - Bounded scenario, 20% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
100% fluxes
100% costs
Power [MW]

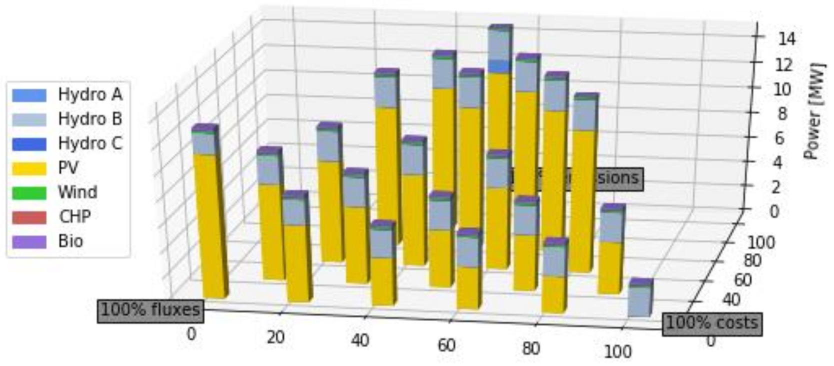

Additional generation for area A10 with weighted sum method - Bounded scenario, 20% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
100% fluxes
100% costs
Power [MW]


Additional generation for area A11 with weighted sum method - Bounded scenario, 20% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
100% fluxes
100% costs
Power [MW]

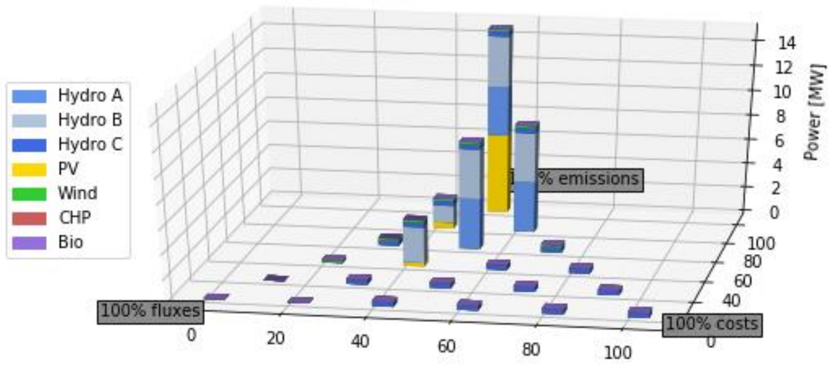
Additional generation for area A12 with weighted sum method - Bounded scenario, 20% el.



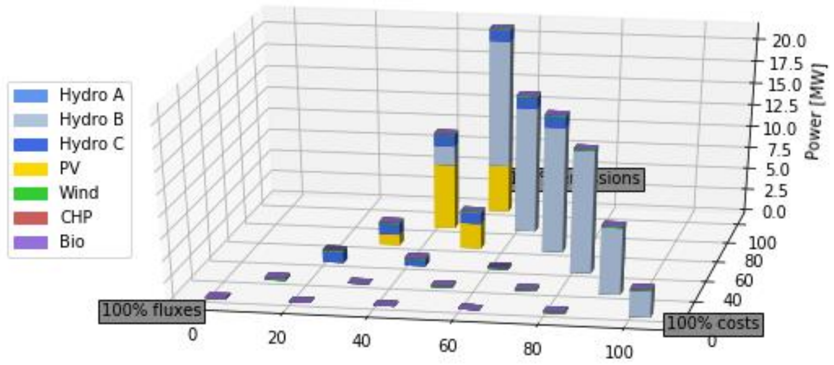
Additional generation for area A13 with weighted sum method - Bounded scenario, 20% el.



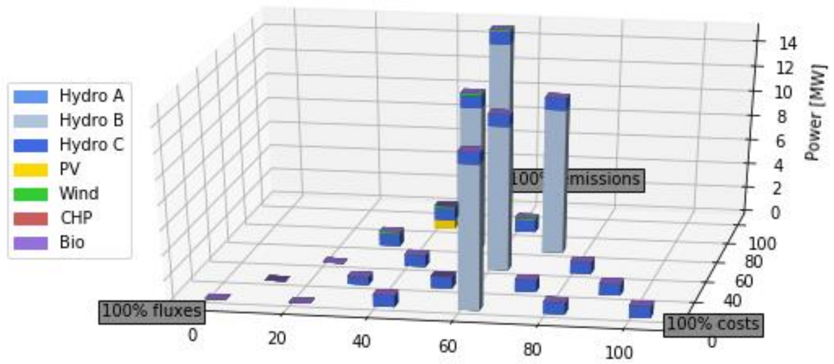
Additional generation for area A14 with weighted sum method - Bounded scenario, 20% el.



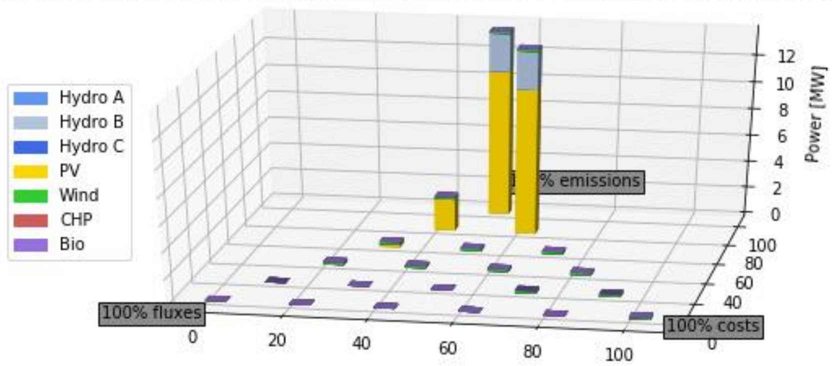
Additional generation for area A15 with weighted sum method - Bounded scenario, 20% el.



Additional generation for area A16 with weighted sum method - Bounded scenario, 20% el.



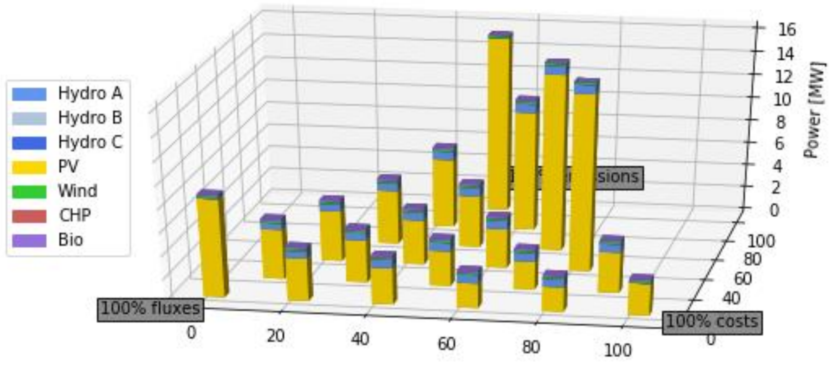
Additional generation for area A17 with weighted sum method - Bounded scenario, 20% el.



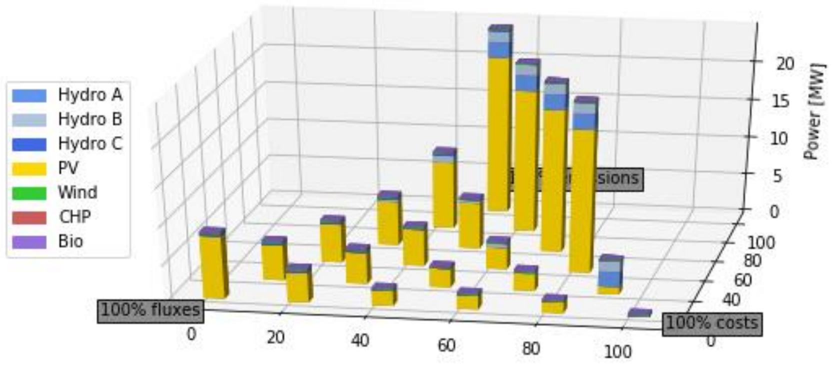
Appendix H – Bounded potential generation with 40% electrification

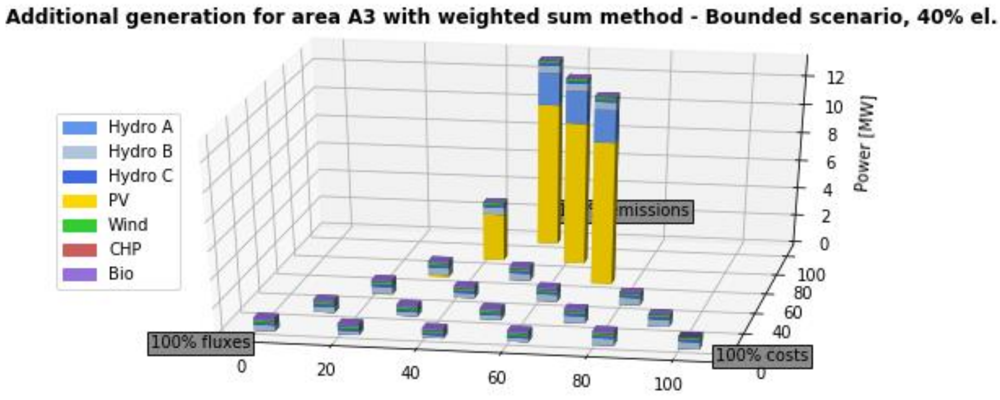
This appendix reports the results of the optimization with weighted sum methodology regarding the "bounded potential" additional generation in the 40% electrification scenario.

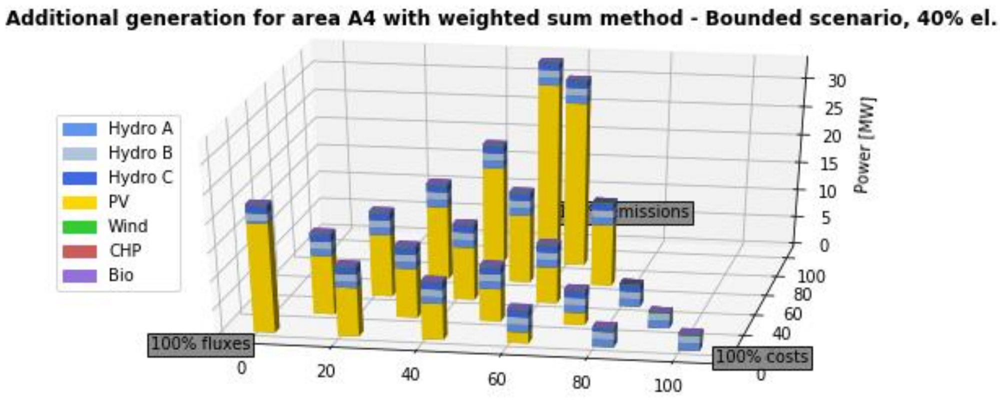
Additional generation for area A1 with weighted sum method - Bounded scenario, 40% el.

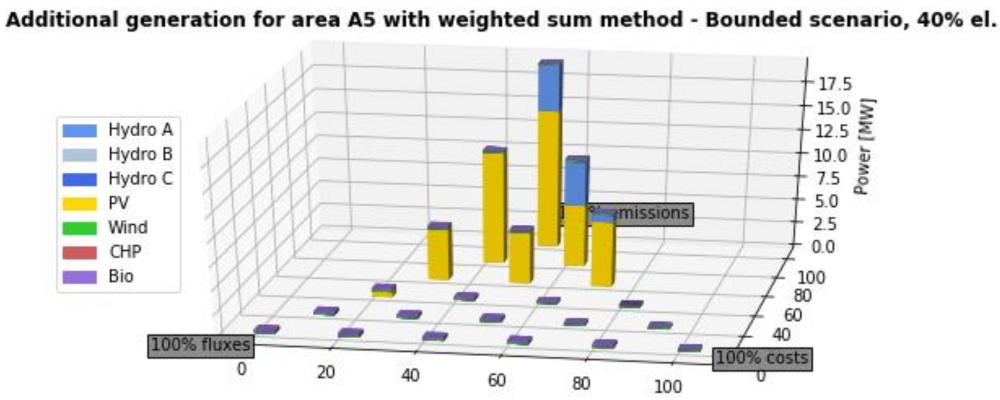


Additional generation for area A2 with weighted sum method - Bounded scenario, 40% el.

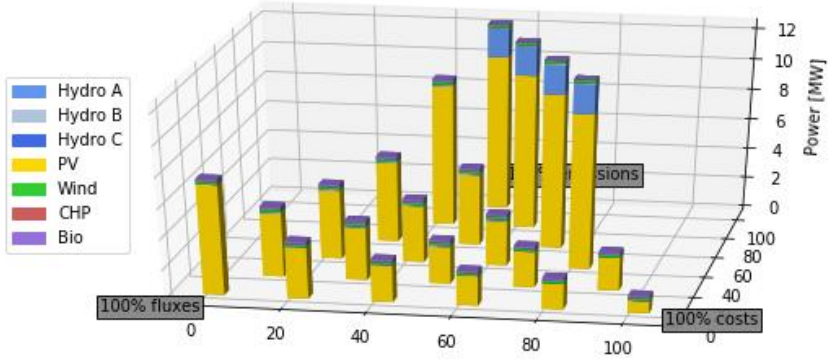



Additional generation for area A3 with weighted sum method - Bounded scenario, 40% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
missions

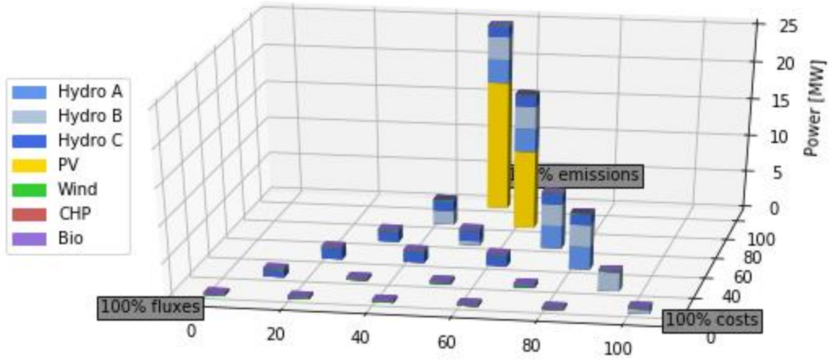

Additional generation for area A4 with weighted sum method - Bounded scenario, 40% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
missions


Additional generation for area A5 with weighted sum method - Bounded scenario, 40% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
missions

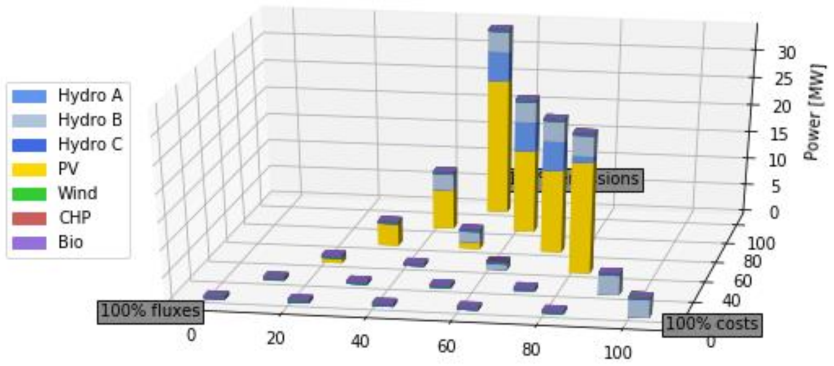
Additional generation for area A6 with weighted sum method - Bounded scenario, 40% el.

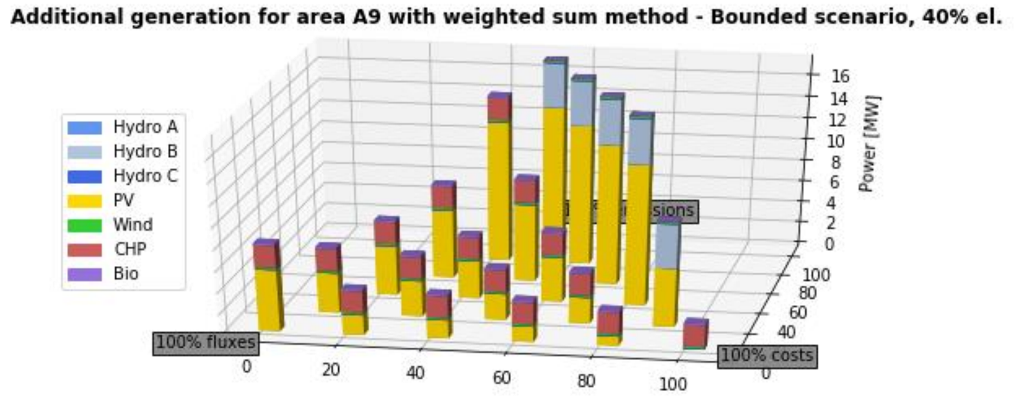


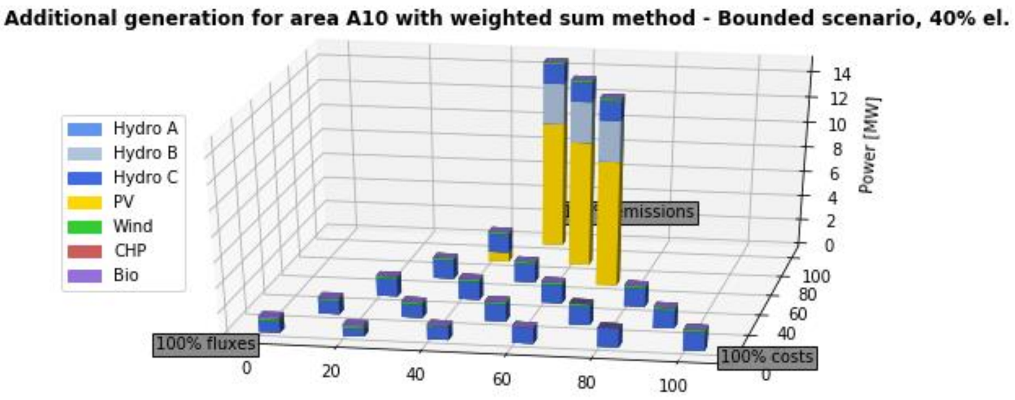
Additional generation for area A7 with weighted sum method - Bounded scenario, 40% el.

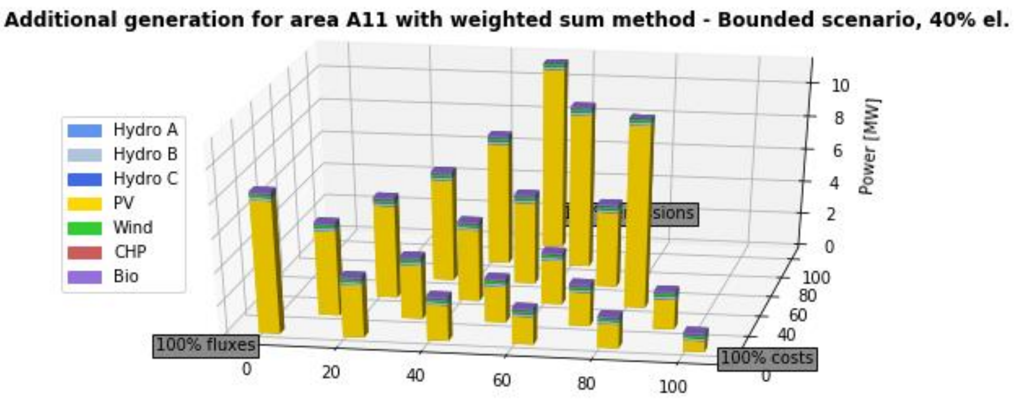


Additional generation for area A8 with weighted sum method - Bounded scenario, 40% el.

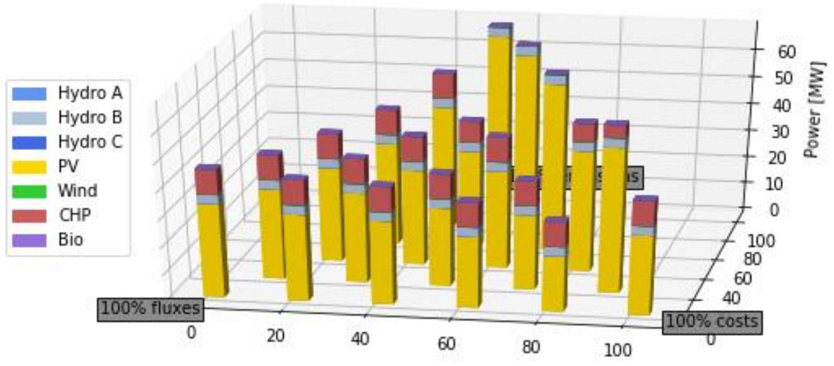



Additional generation for area A9 with weighted sum method - Bounded scenario, 40% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100

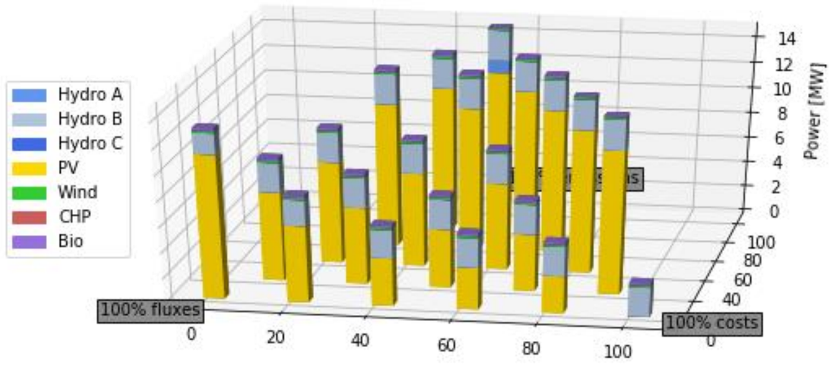

Additional generation for area A10 with weighted sum method - Bounded scenario, 40% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100


Additional generation for area A11 with weighted sum method - Bounded scenario, 40% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100

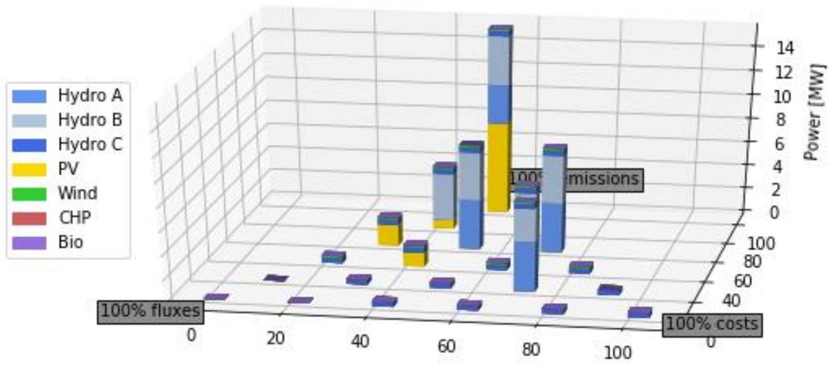
Additional generation for area A12 with weighted sum method - Bounded scenario, 40% el.

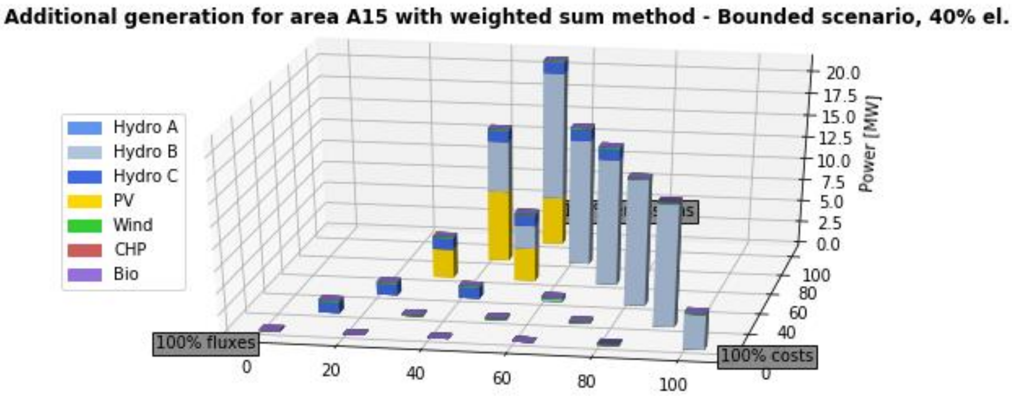


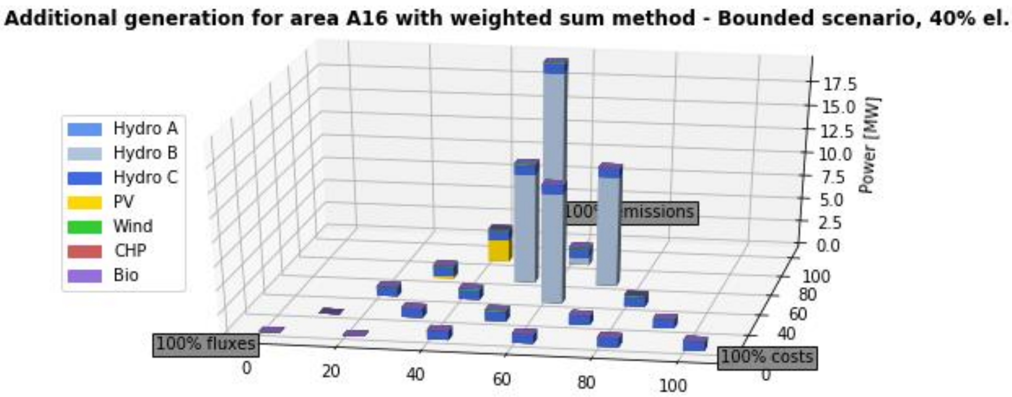
Additional generation for area A13 with weighted sum method - Bounded scenario, 40% el.

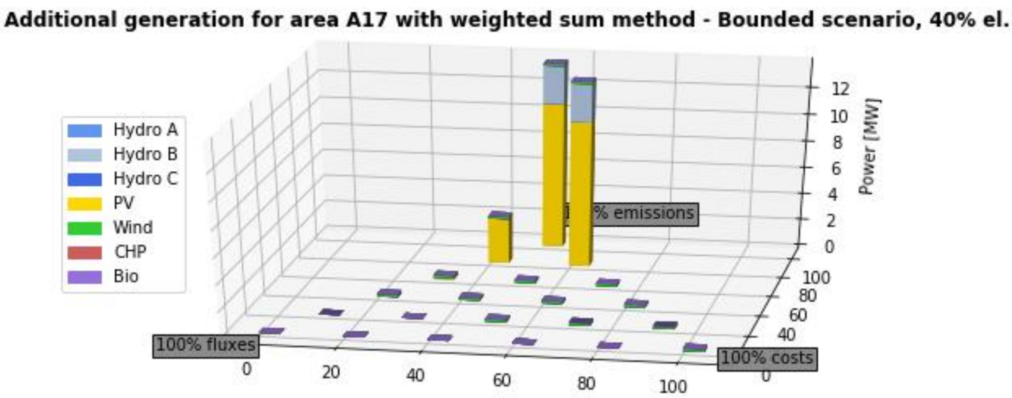


Additional generation for area A14 with weighted sum method - Bounded scenario, 40% el.



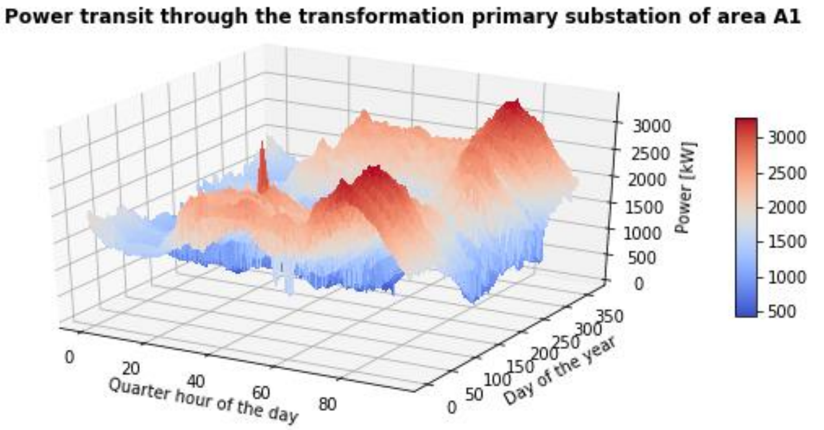

Additional generation for area A15 with weighted sum method - Bounded scenario, 40% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100

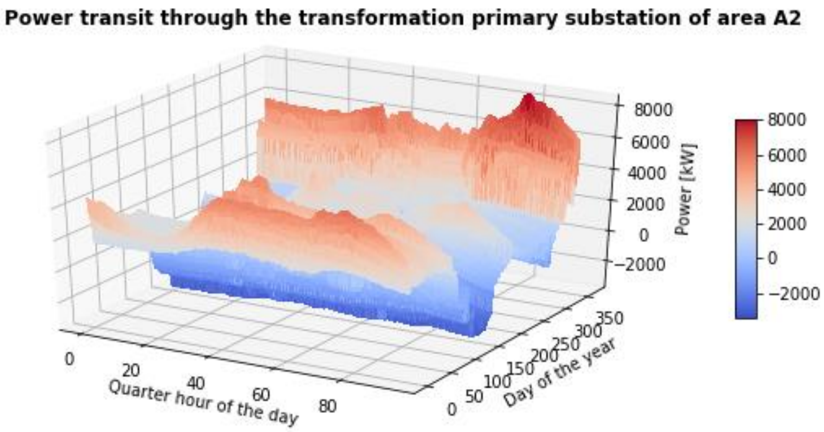

Additional generation for area A16 with weighted sum method - Bounded scenario, 40% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100


Additional generation for area A17 with weighted sum method - Bounded scenario, 40% el.
Hydro A
Hydro B
Hydro C
PV
Wind
CHP
Bio
Power [MW]
100% fluxes
100% costs
0
20
40
60
80
100

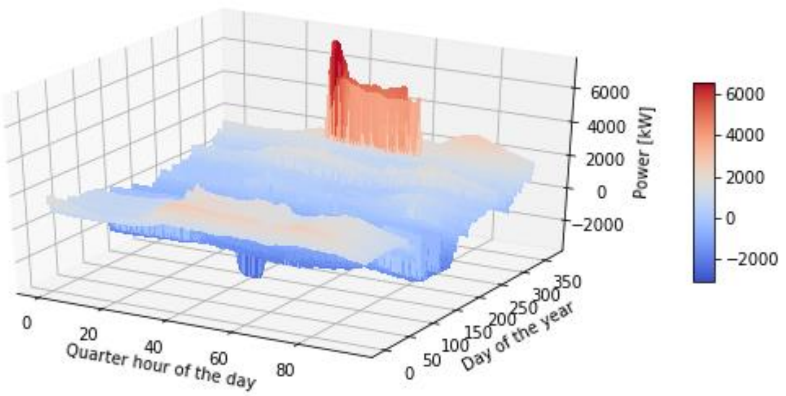
Appendix I – Initial transit profiles

This appendix reports the initial power transit through the primary transformation substation for all areas, i.e. the initial transits prior to the optimization processes.

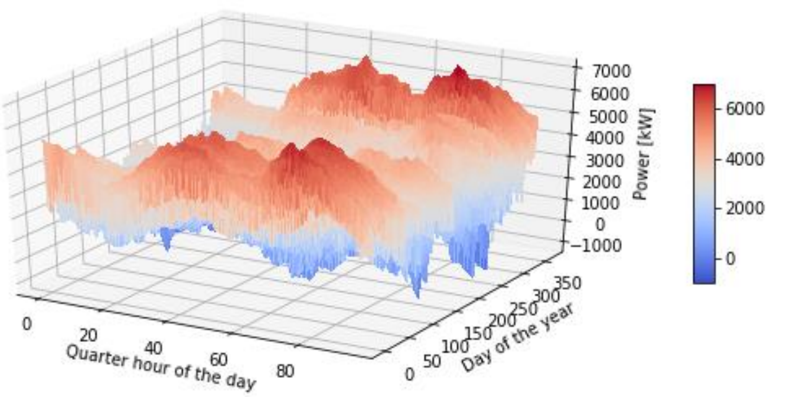




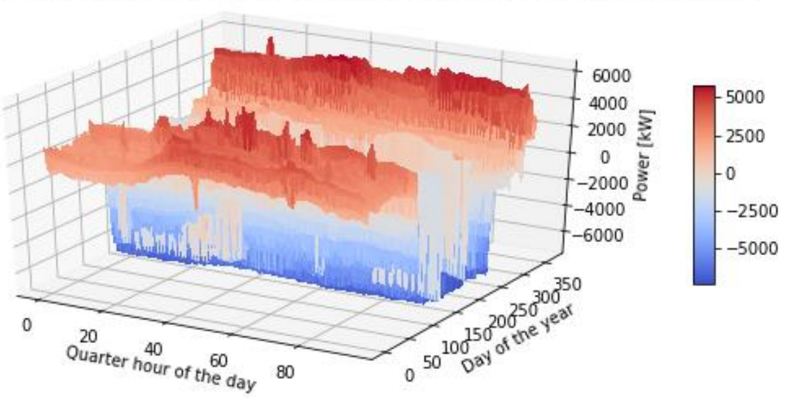
Power transit through the transformation primary substation of area A3

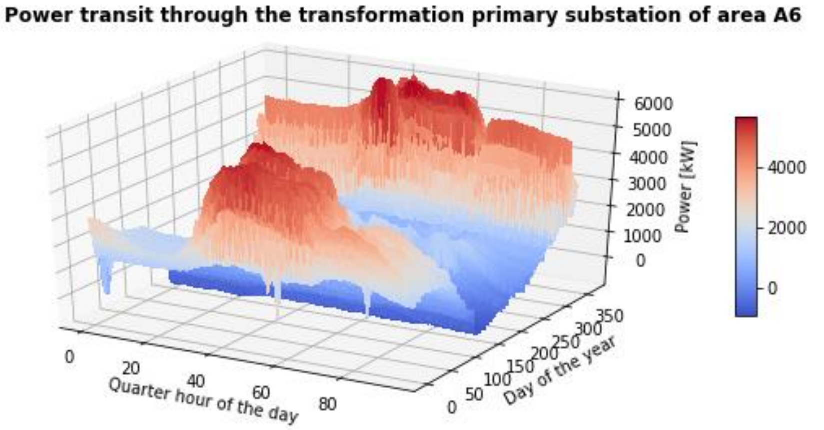


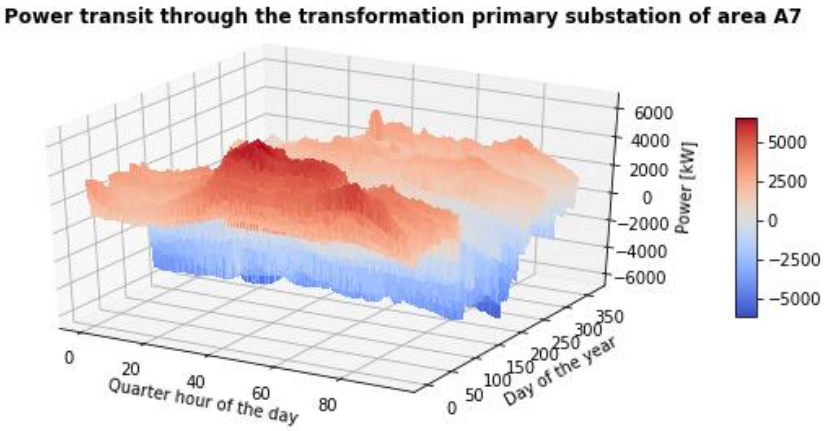
Power transit through the transformation primary substation of area A4

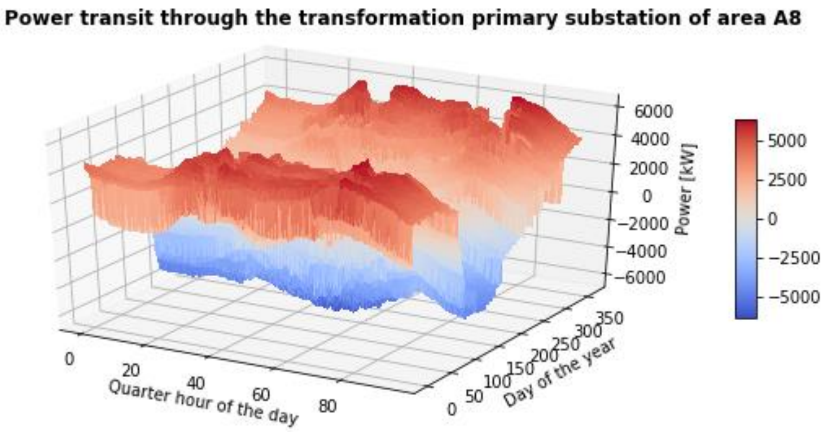


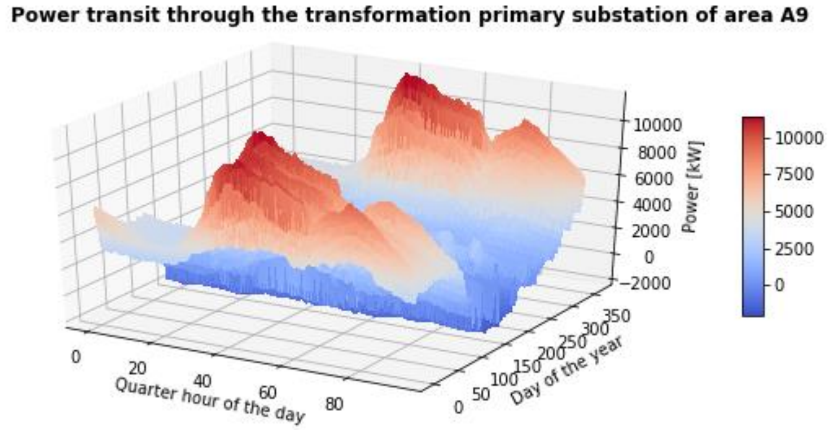
Power transit through the transformation primary substation of area A5

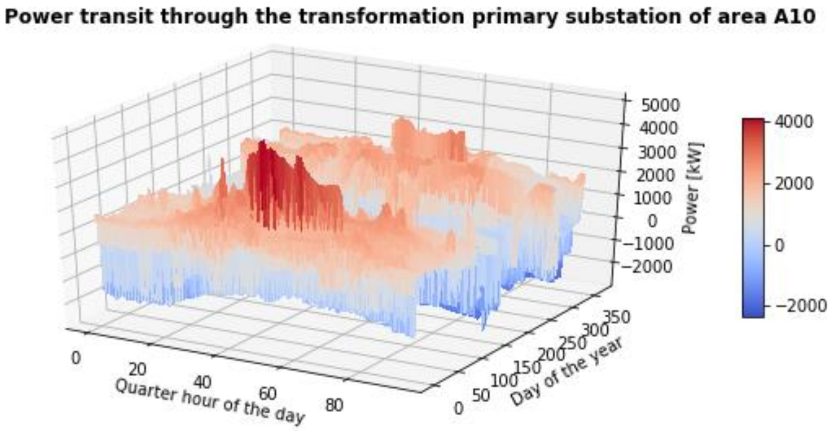


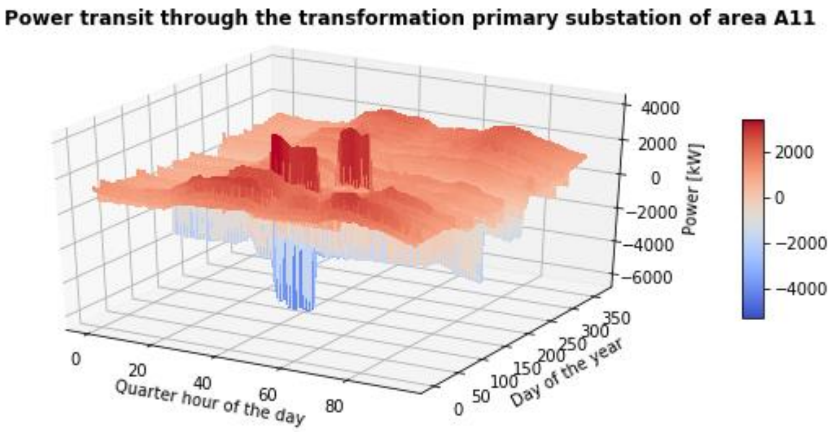

Power transit through the transformation primary substation of area A6
Quarter hour of the day
Day of the year
Power [kW]

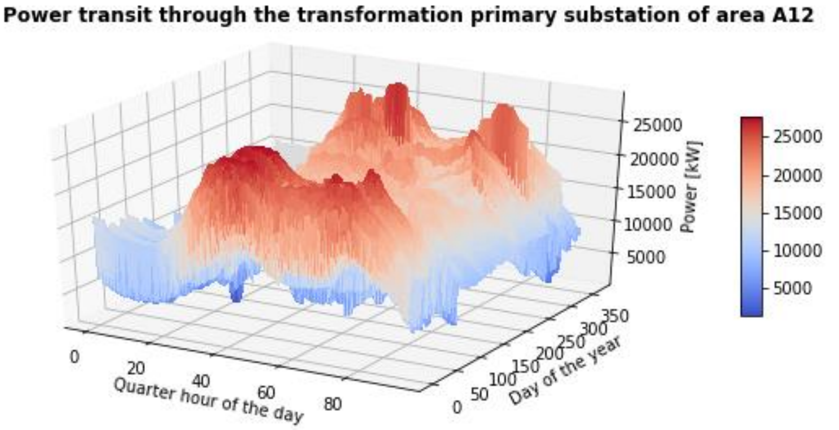

Power transit through the transformation primary substation of area A7
Quarter hour of the day
Day of the year
Power [kW]

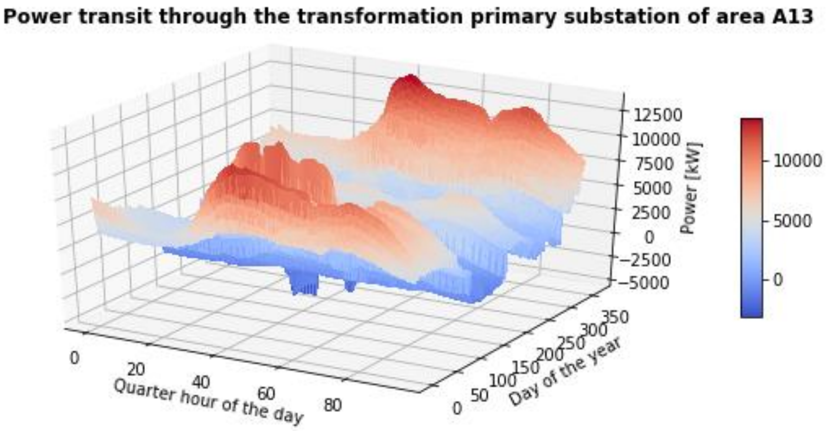

Power transit through the transformation primary substation of area A8
Quarter hour of the day
Day of the year
Power [kW]

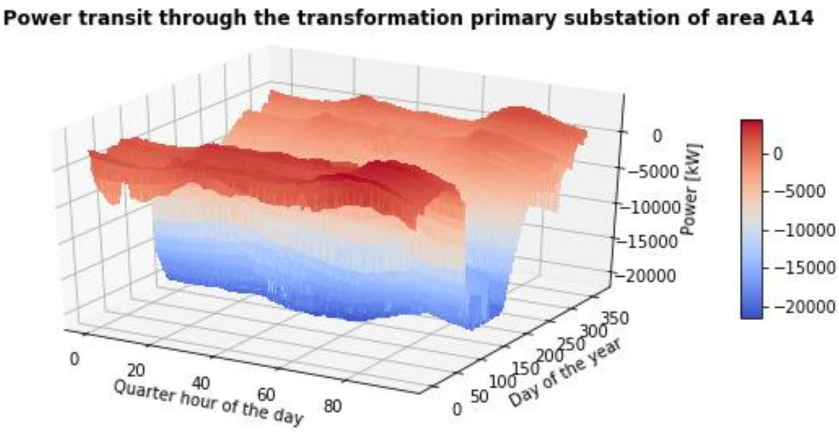

Power transit through the transformation primary substation of area A9
Quarter hour of the day
Day of the year
Power [kW]

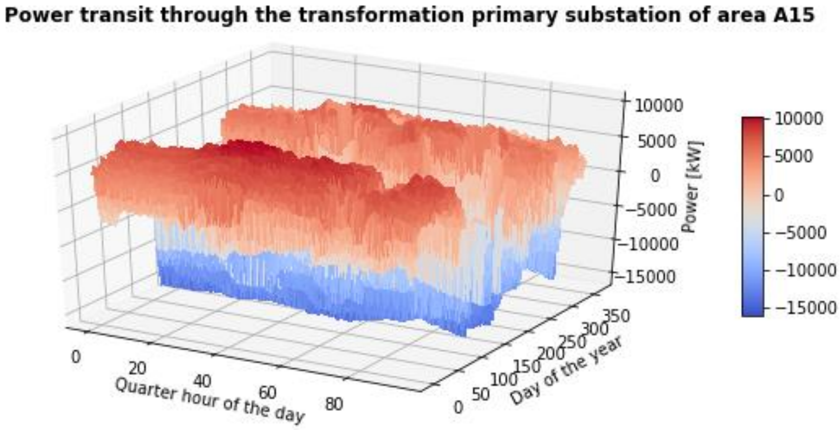

Power transit through the transformation primary substation of area A10
Quarter hour of the day
Day of the year
Power [kW]

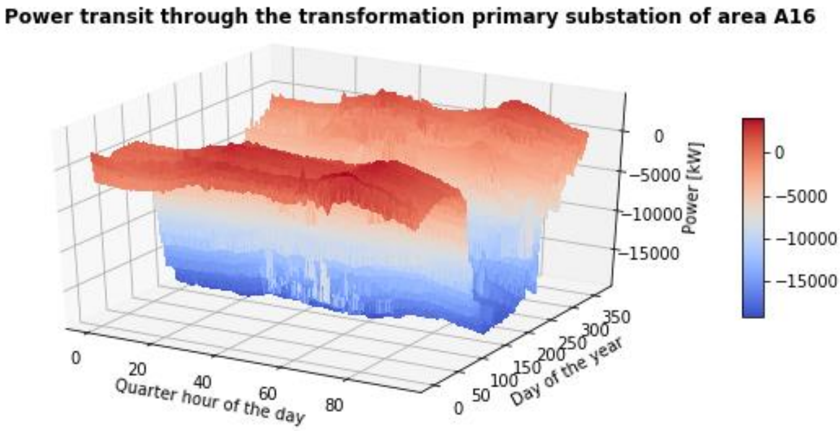

Power transit through the transformation primary substation of area A11
Quarter hour of the day
Day of the year
Power [kW]

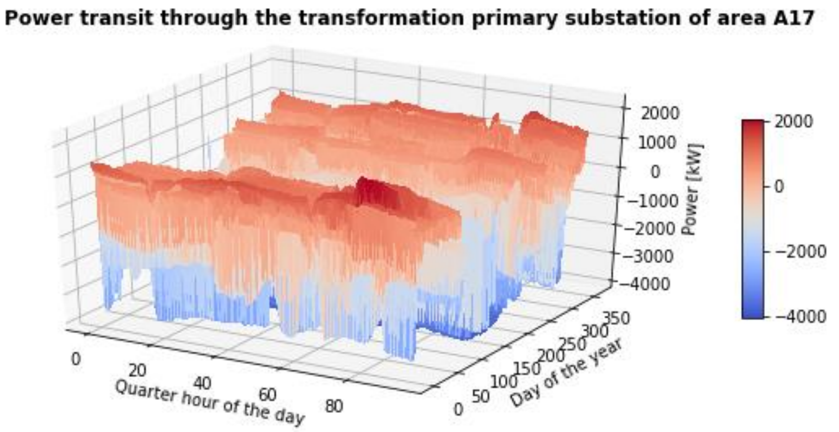

Power transit through the transformation primary substation of area A12
25000
20000
15000
10000
5000
Power [kW]
0
20
40
60
80
Quarter hour of the day
0
50
100
150
200
250
300
350
Day of the year


Power transit through the transformation primary substation of area A13
12500
10000
7500
5000
2500
0
−2500
−5000
Power [kW]
Quarter hour of the day
Day of the year


Power transit through the transformation primary substation of area A14
0
−5000
−10000
−15000
−20000
Power [kW]
Quarter hour of the day
Day of the year

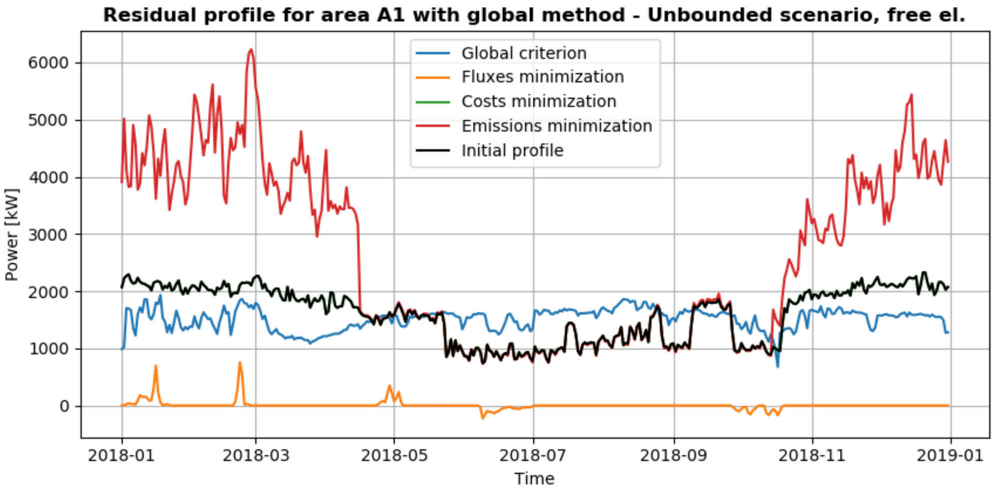

Power transit through the transformation primary substation of area A15
Power [kW]
Quarter hour of the day
Day of the year

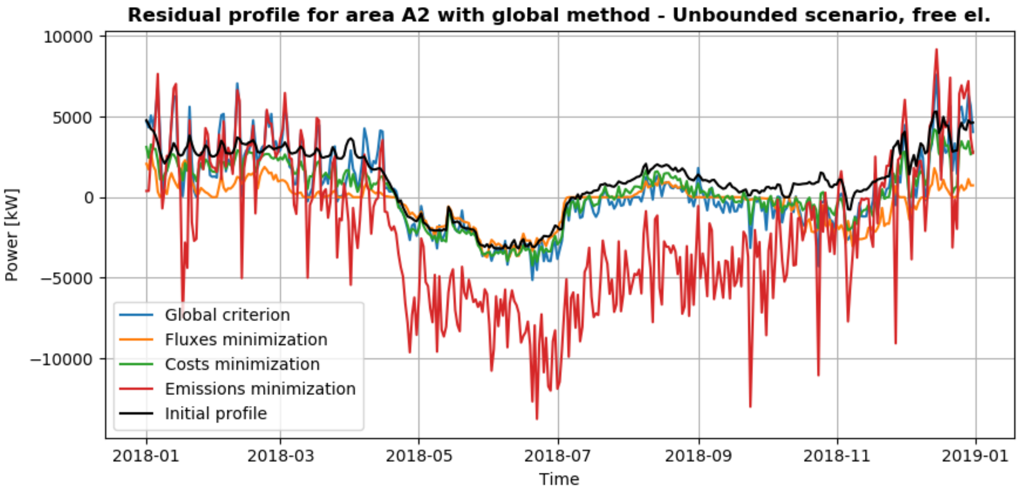

Power transit through the transformation primary substation of area A16
Power [kW]
Quarter hour of the day
Day of the year

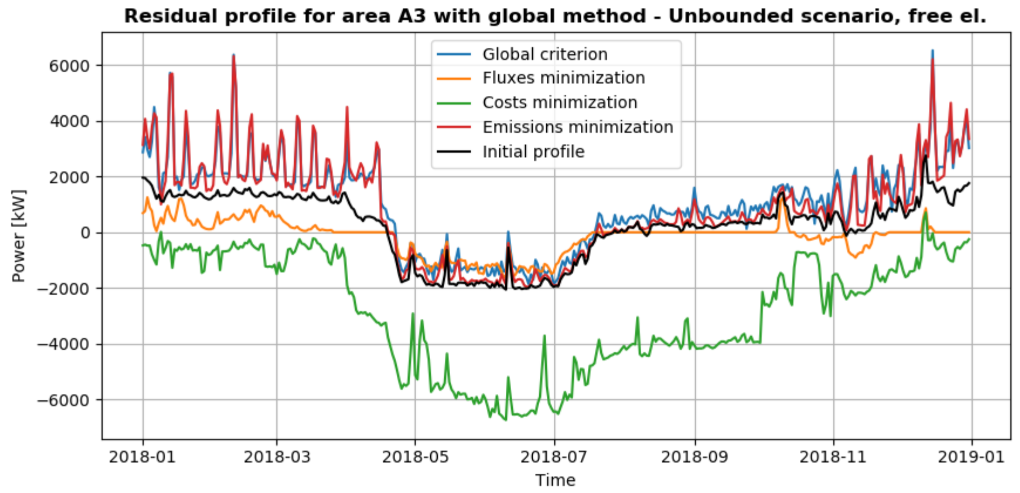

Power transit through the transformation primary substation of area A17
Power [kW]
Quarter hour of the day
Day of the year

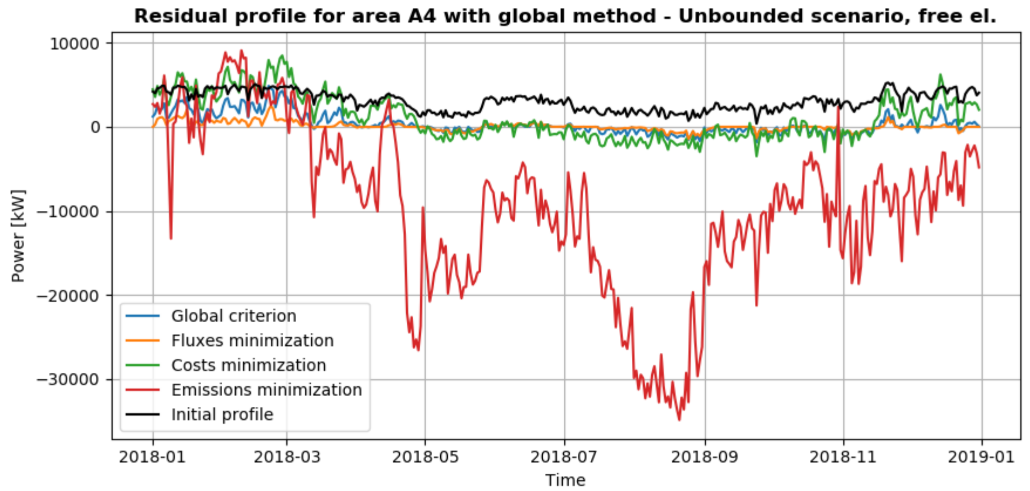
Appendix J – Residual profiles in unbounded potential scenario with free electrification

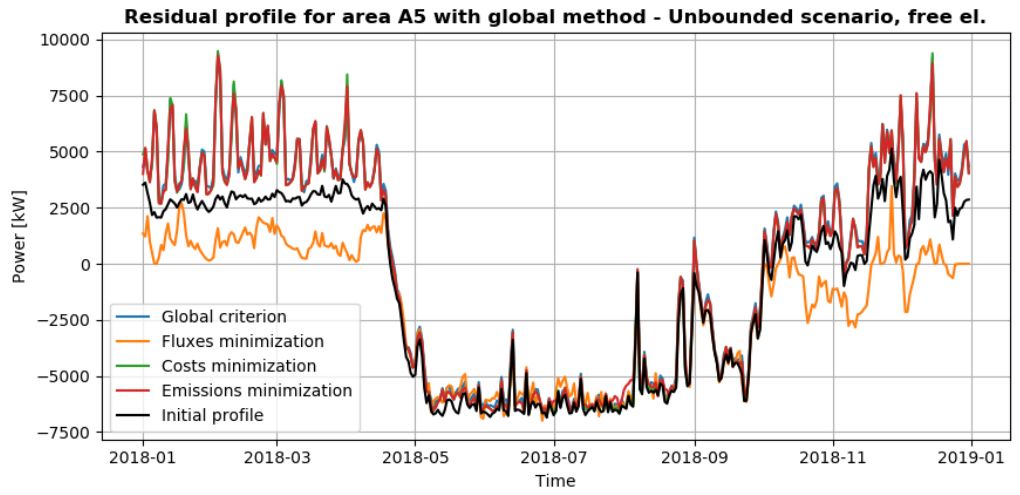
This appendix reports the results for the residual profiles – i.e. post-optimization – for all areas and for different objectives in the unbounded potential scenario. The residual profile following the global criterion optimization is reported too.

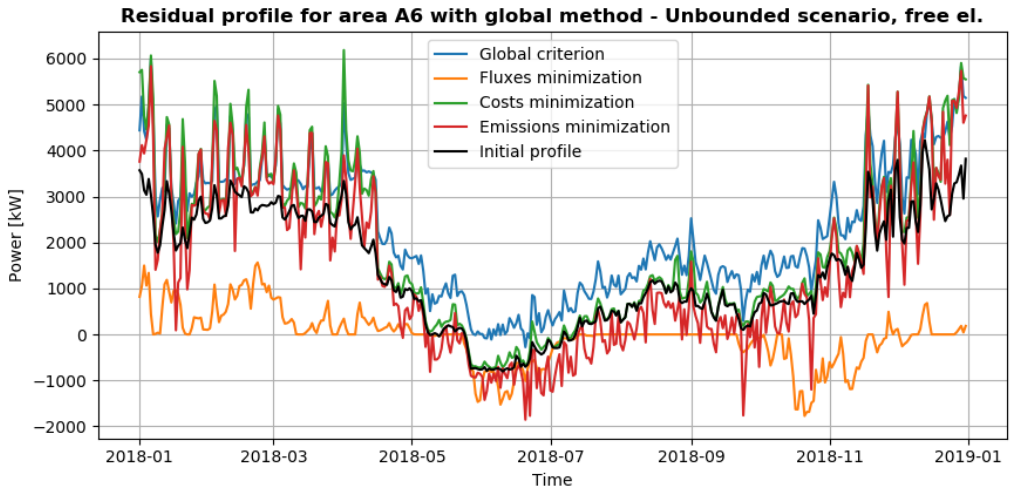


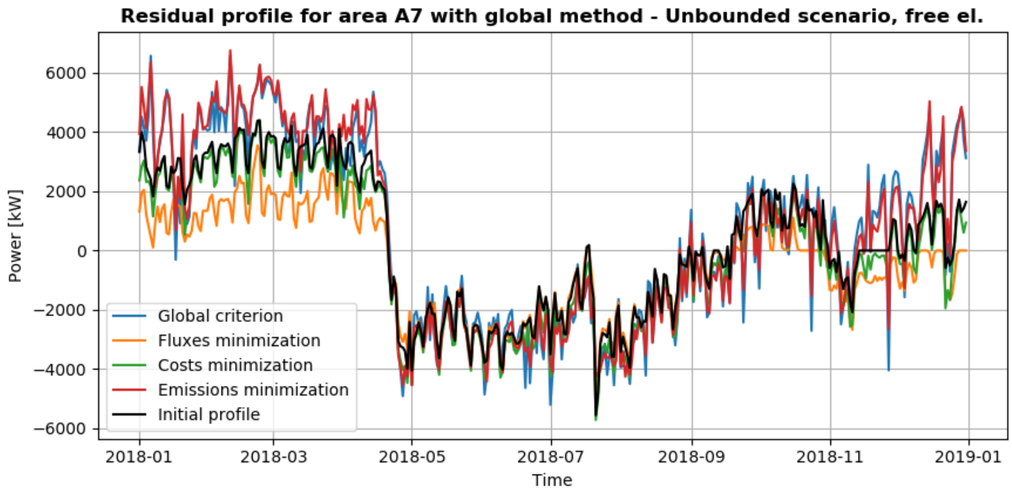


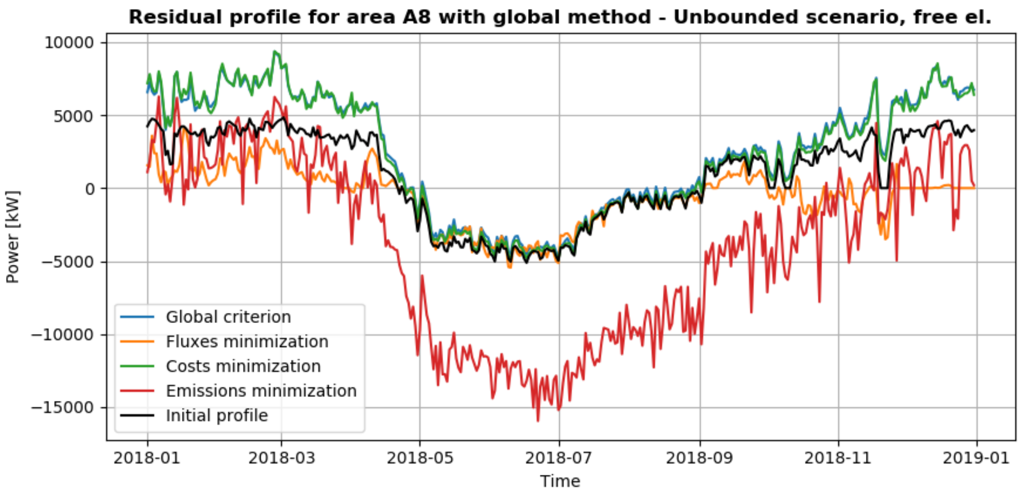

Residual profile for area A3 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
6000
4000
2000
0
−2000
−4000
−6000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

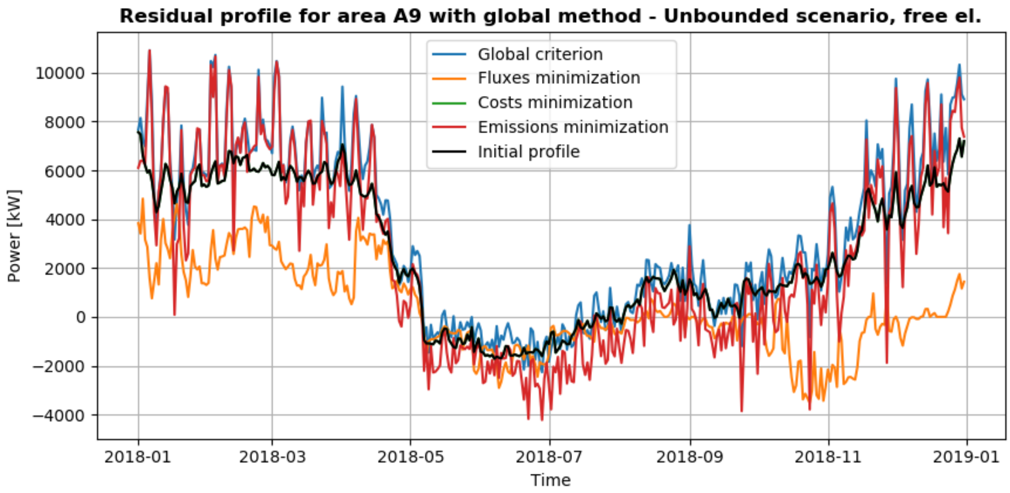

Residual profile for area A4 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
10000
0
−10000
−20000
−30000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

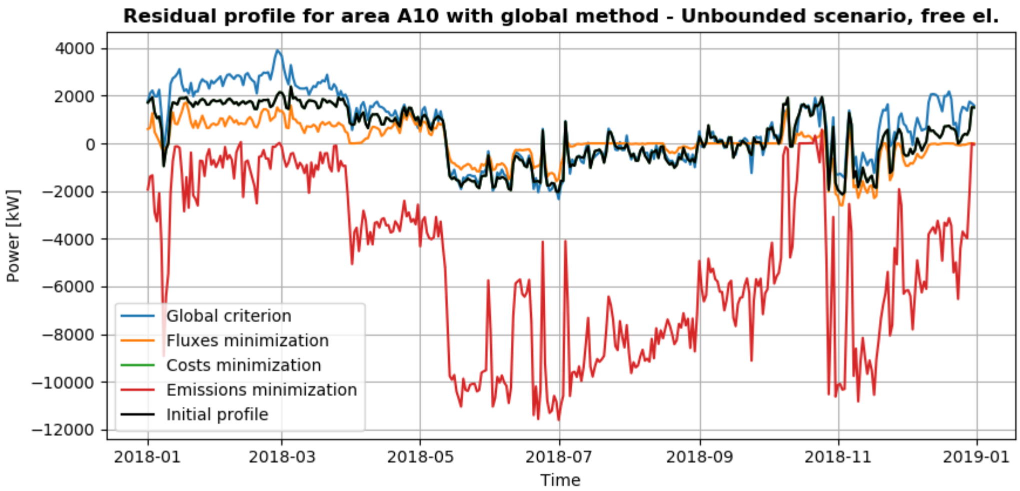

Residual profile for area A5 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
10000
7500
5000
2500
0
−2500
−5000
−7500
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

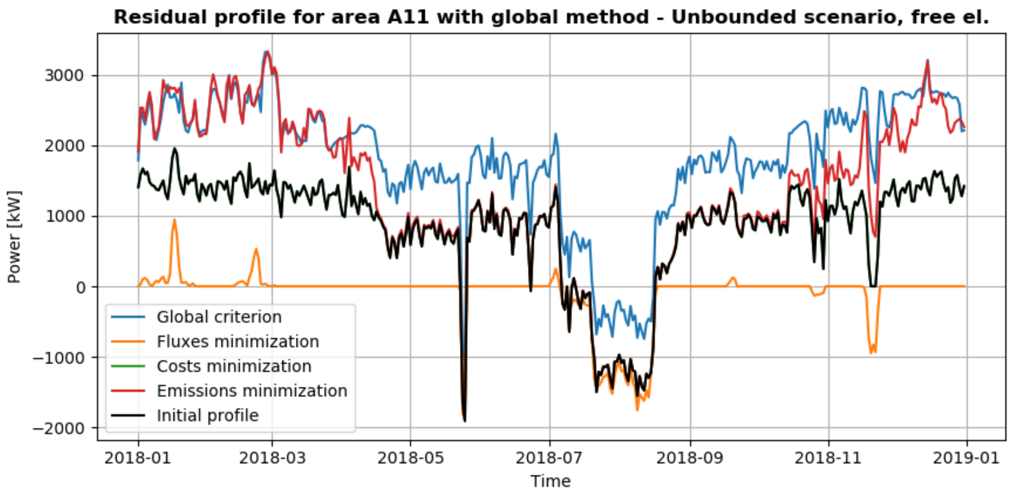

Residual profile for area A6 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
Time
6000
5000
4000
3000
2000
1000
0
−1000
−2000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01

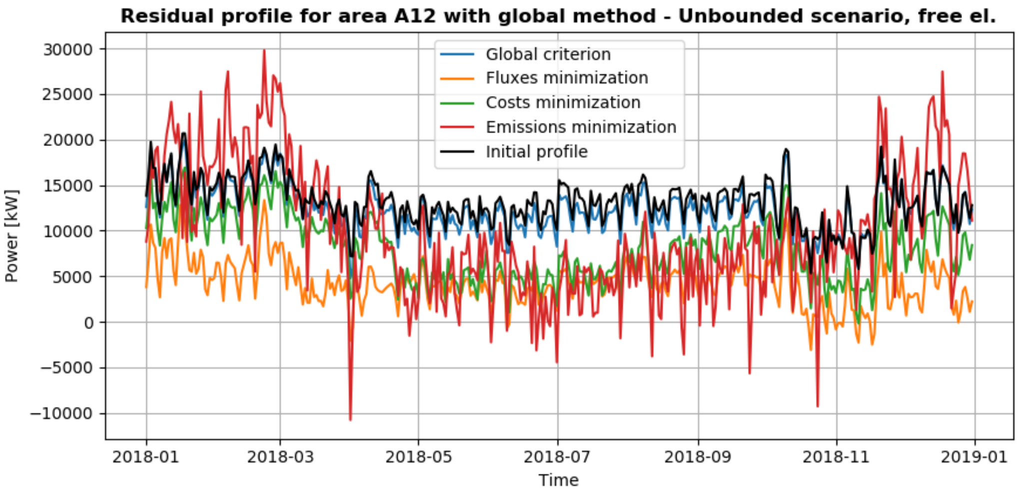

Residual profile for area A7 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
Time
6000
4000
2000
0
−2000
−4000
−6000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01

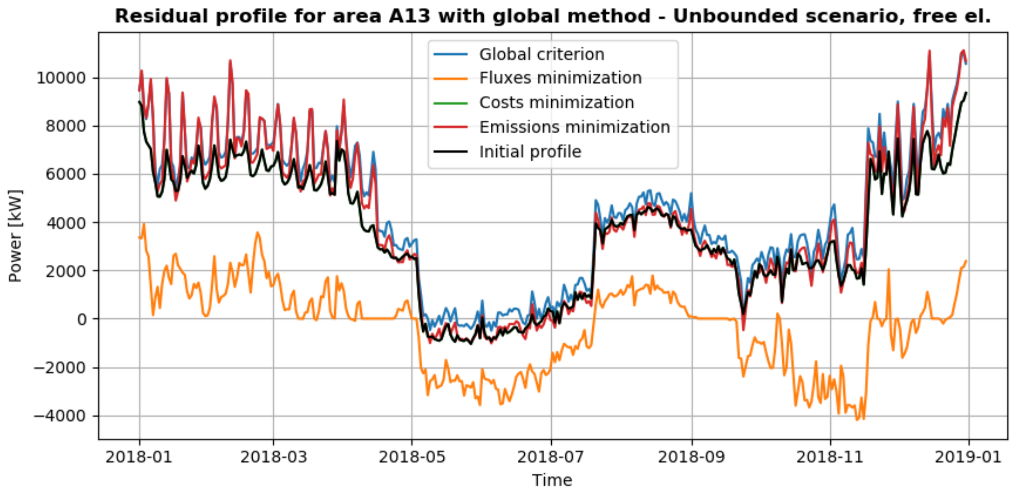

Residual profile for area A8 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
Time
10000
5000
0
−5000
−10000
−15000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01

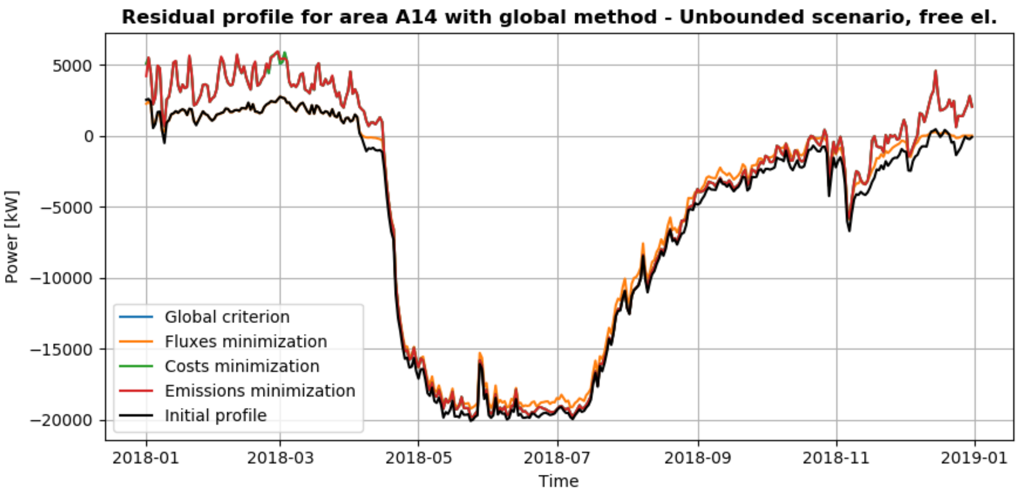

Residual profile for area A9 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
10000
8000
6000
4000
2000
0
−2000
−4000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

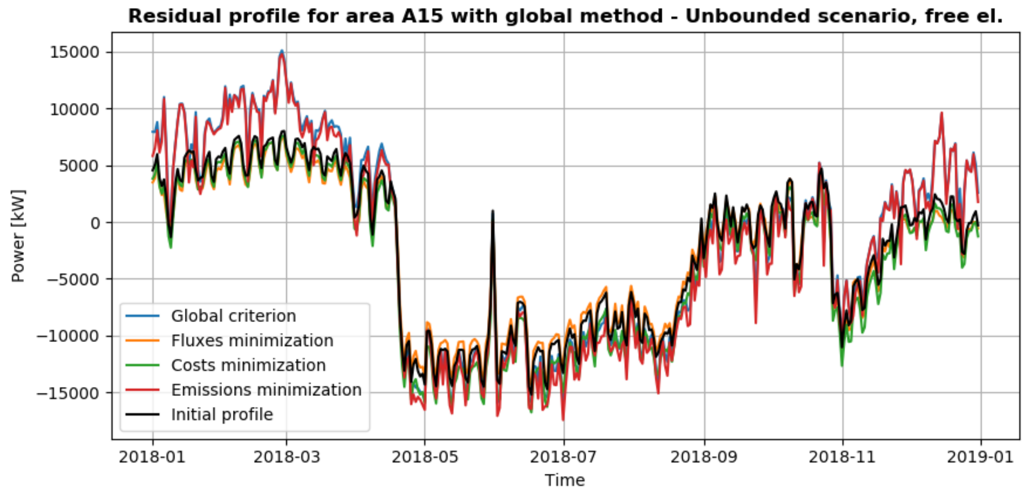

Residual profile for area A10 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
4000
2000
0
−2000
−4000
−6000
−8000
−10000
−12000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

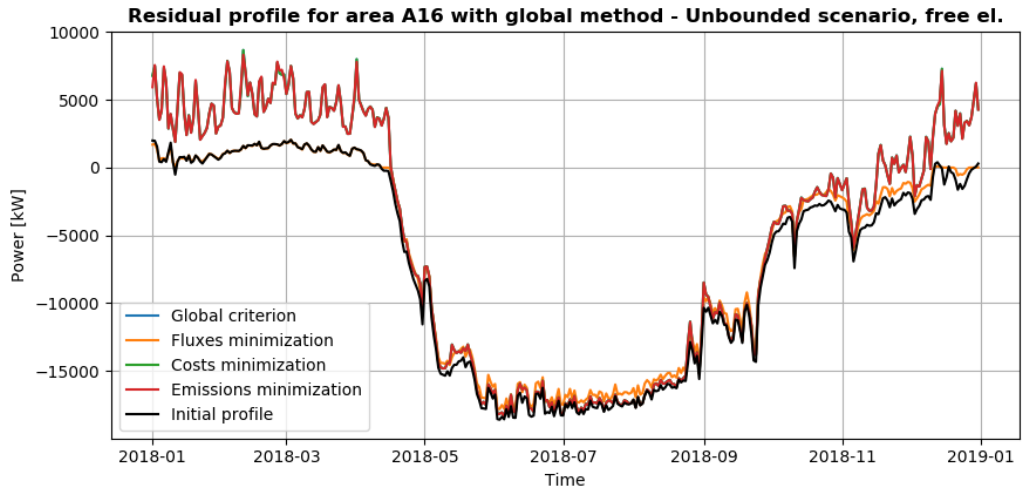

Residual profile for area A11 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
3000
2000
1000
0
−1000
−2000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

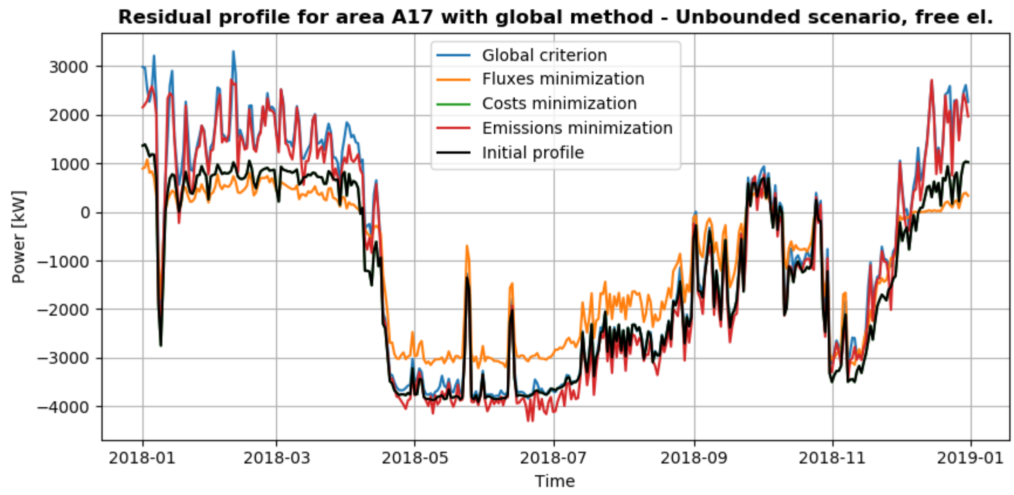

Residual profile for area A12 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
Time
30000
25000
20000
15000
10000
5000
0
−5000
−10000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01


Residual profile for area A13 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
Time
10000
8000
6000
4000
2000
0
−2000
−4000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01


Residual profile for area A14 with global method - Unbounded scenario, free el.
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
Power [kW]
Time
5000
0
−5000
−10000
−15000
−20000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01

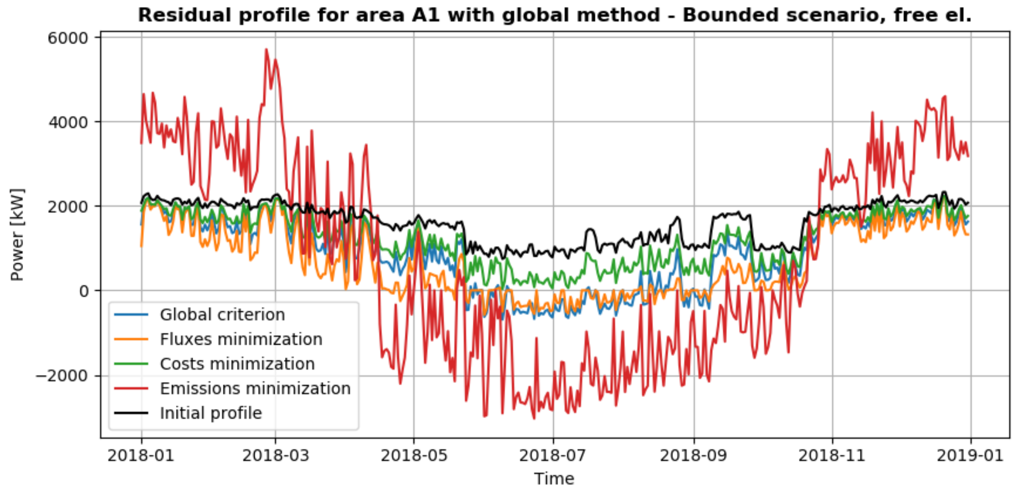

Residual profile for area A15 with global method - Unbounded scenario, free el.
15000
10000
5000
0
−5000
−10000
−15000
Power [kW]
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

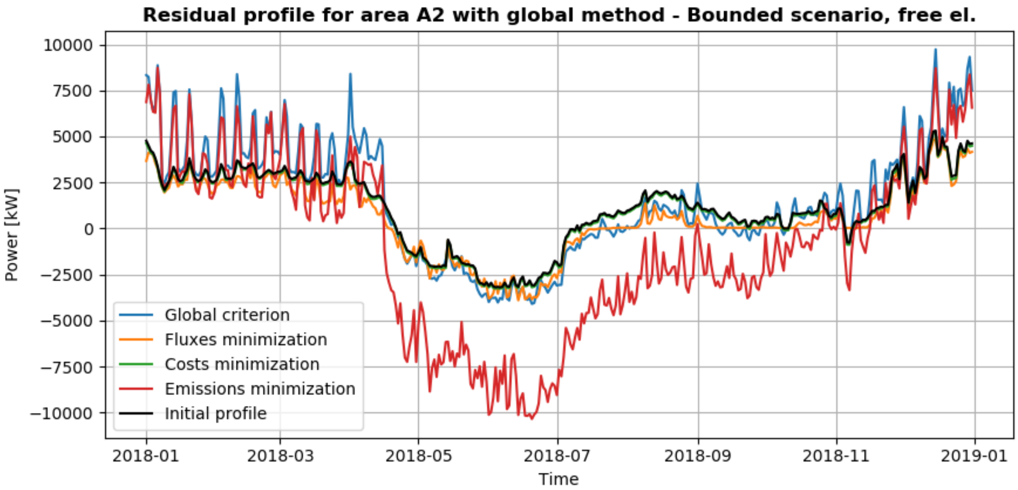

Residual profile for area A16 with global method - Unbounded scenario, free el.
10000
5000
0
−5000
−10000
−15000
Power [kW]
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

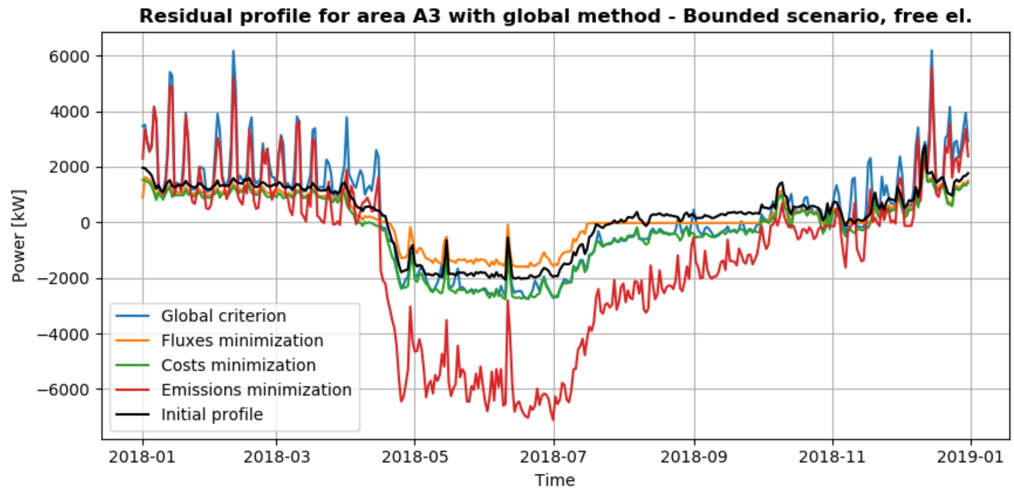

Residual profile for area A17 with global method - Unbounded scenario, free el.
3000
2000
1000
0
−1000
−2000
−3000
−4000
Power [kW]
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

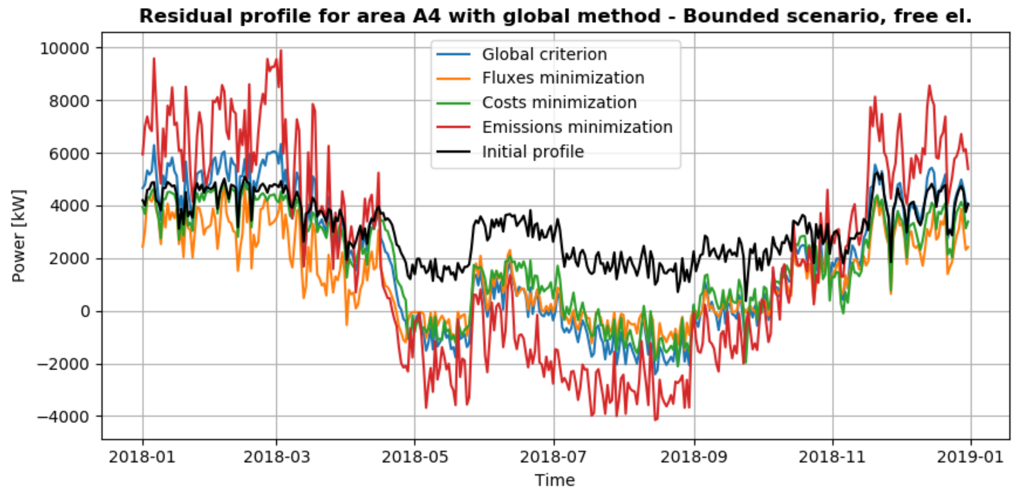
Appendix K – Residual profiles in bounded potential scenario with free electrification

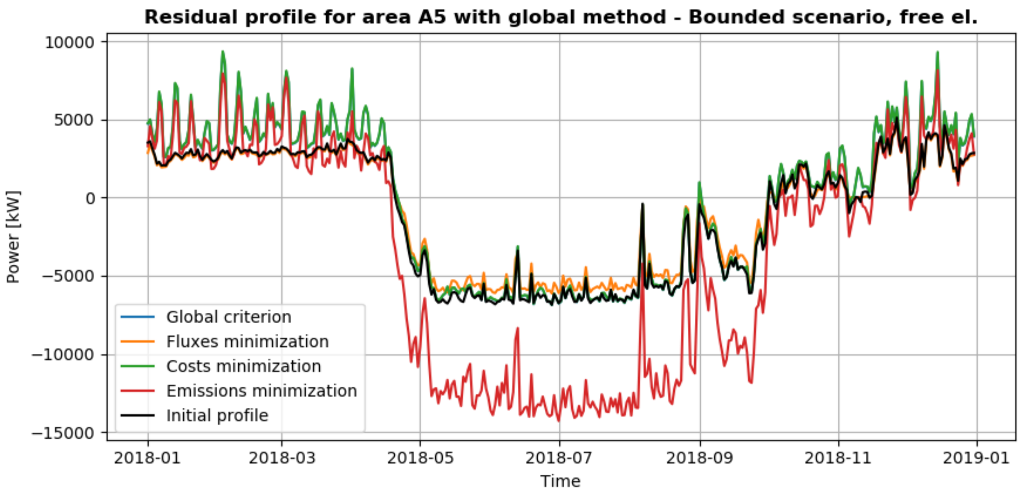
This appendix reports the results for the residual profiles – i.e. post-optimization – for all areas and for different objectives in the bounded potential scenario. The residual profile following the global criterion optimization is reported too.

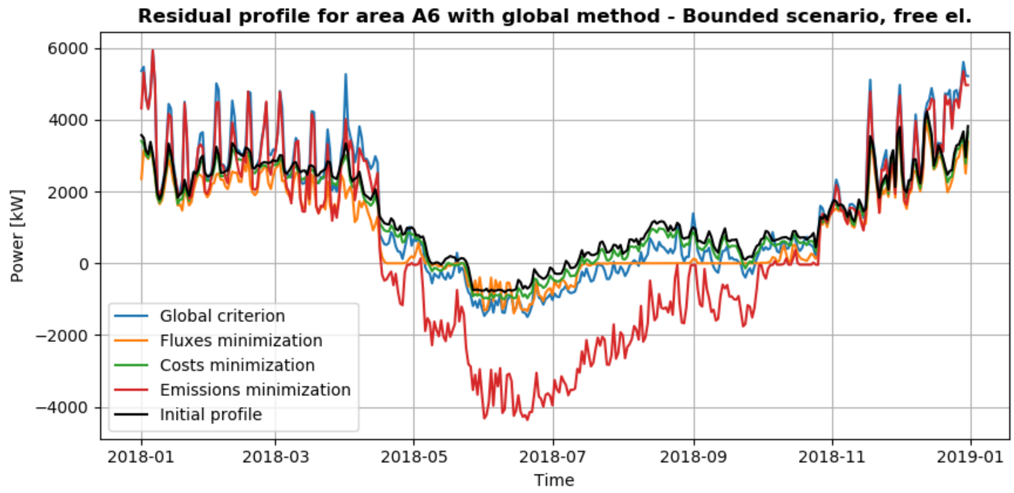


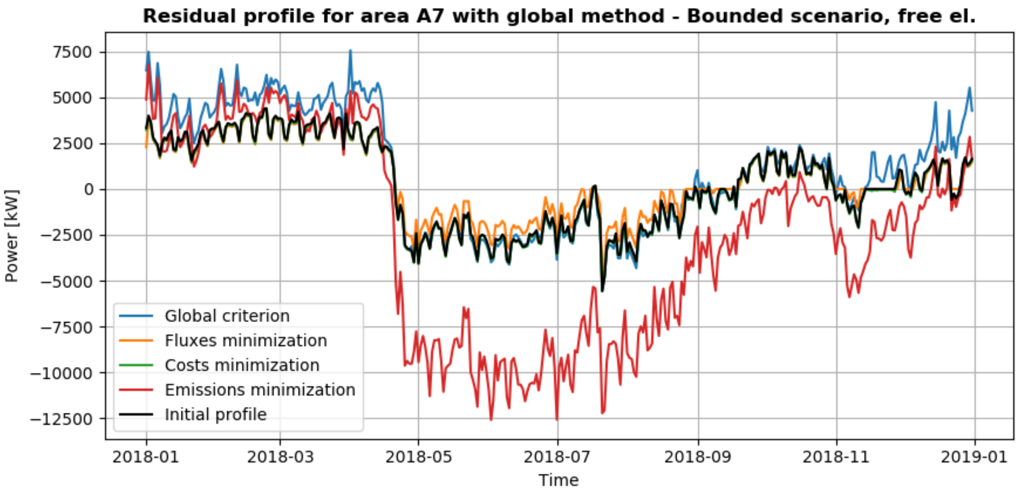


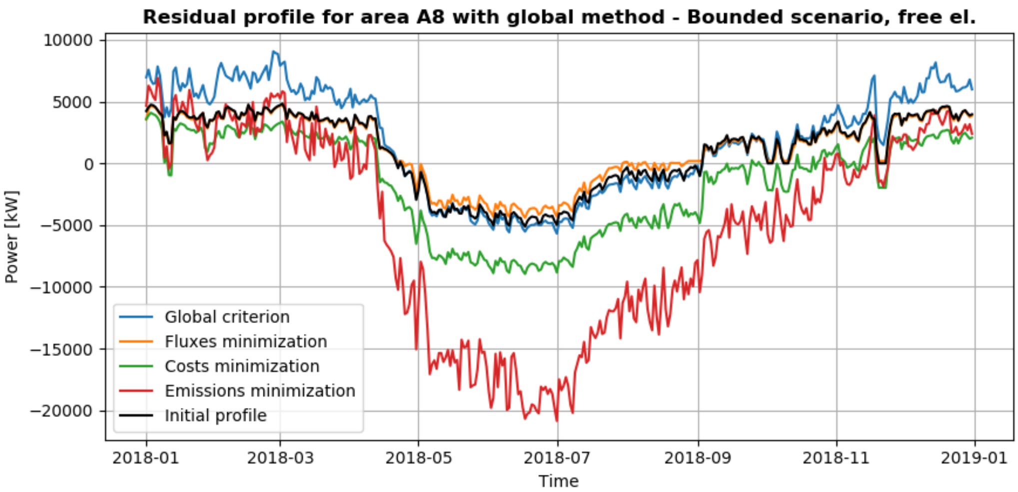

Residual profile for area A3 with global method - Bounded scenario, free el.
Power [kW]
6000
4000
2000
0
−2000
−4000
−6000
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

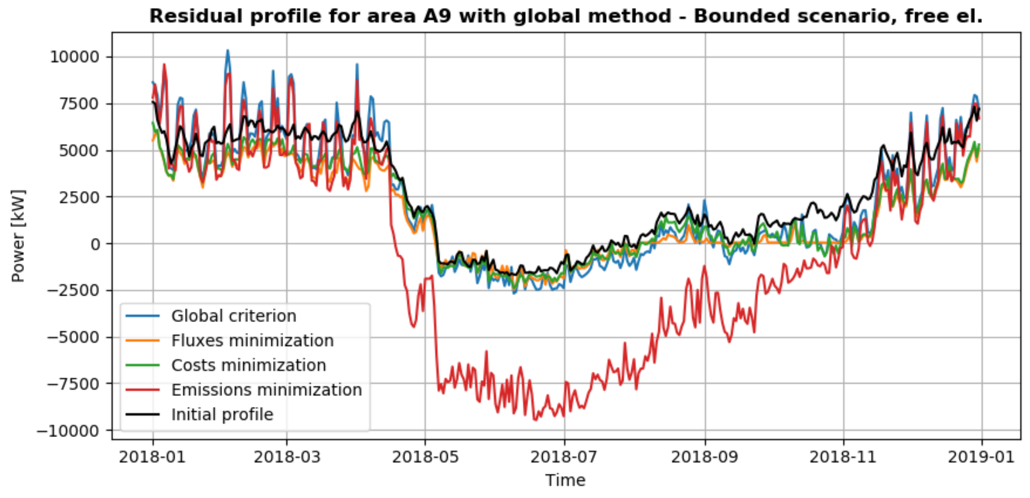

Residual profile for area A4 with global method - Bounded scenario, free el.
Power [kW]
10000
8000
6000
4000
2000
0
−2000
−4000
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

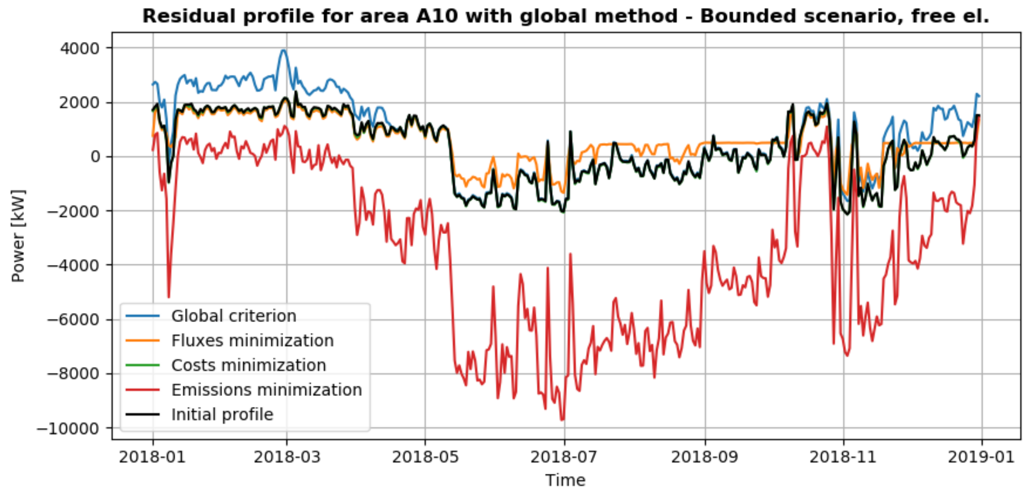

Residual profile for area A5 with global method - Bounded scenario, free el.
Power [kW]
10000
5000
0
−5000
−10000
−15000
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

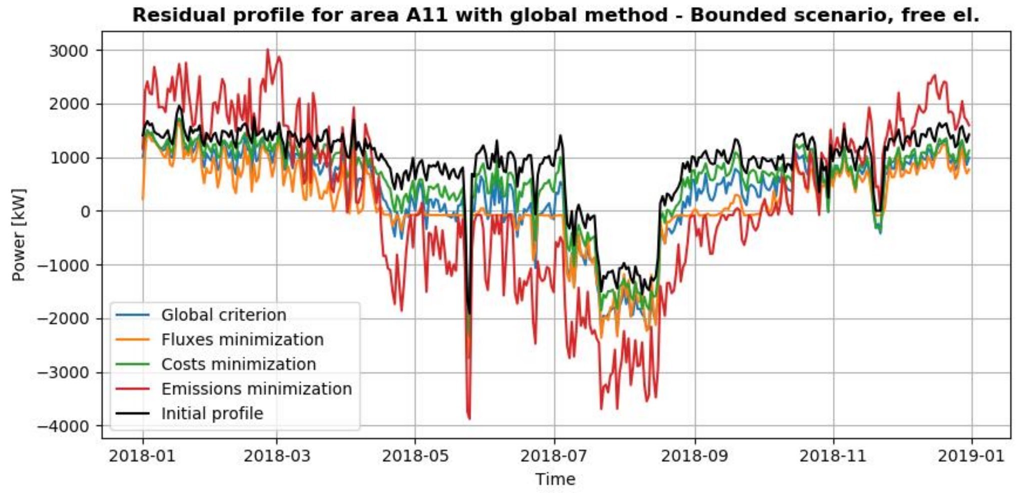

Residual profile for area A6 with global method - Bounded scenario, free el.
Power [kW]
Time
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile

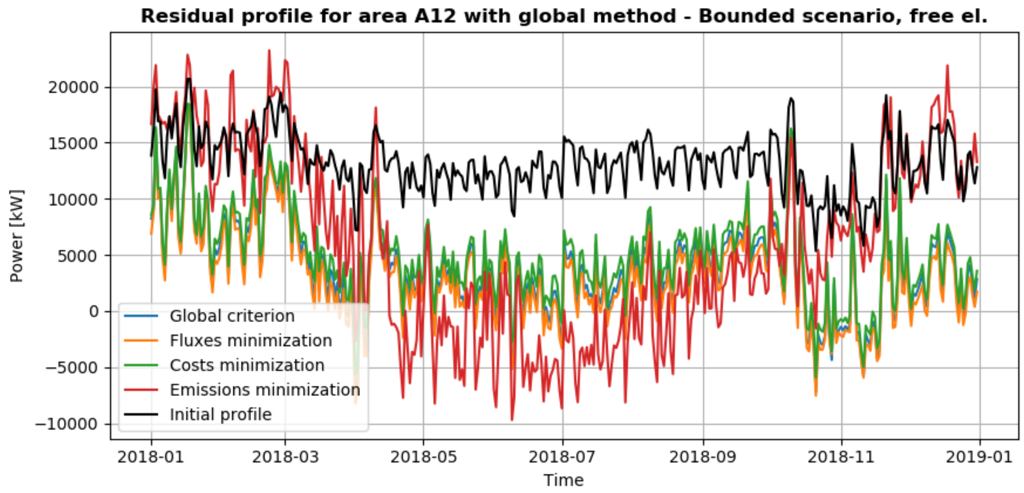

Residual profile for area A7 with global method - Bounded scenario, free el.
Power [kW]
Time
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile

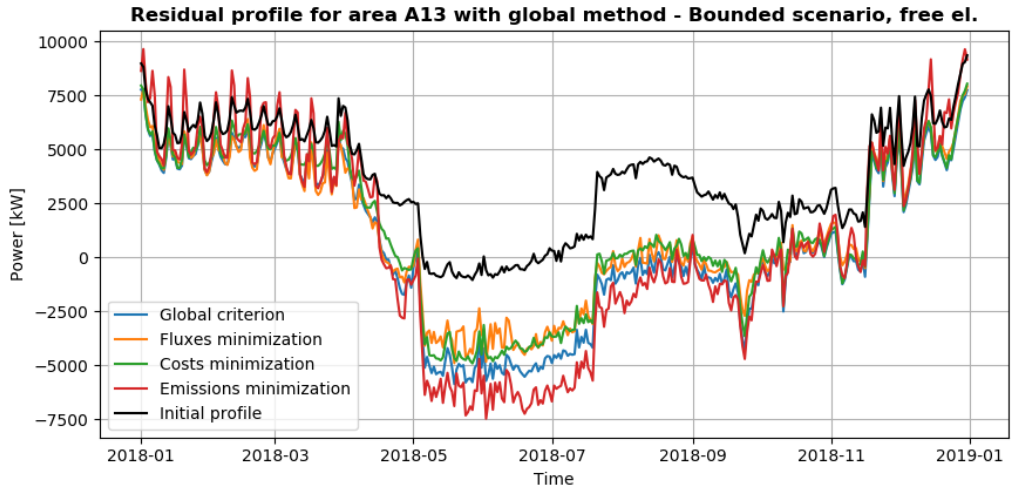

Residual profile for area A8 with global method - Bounded scenario, free el.
Power [kW]
Time
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile

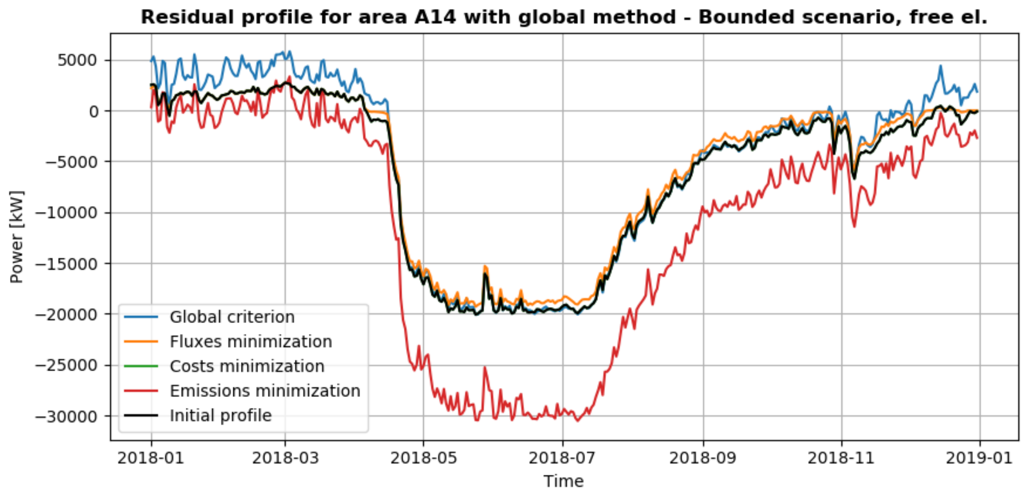

Residual profile for area A9 with global method - Bounded scenario, free el.
Power [kW]
Time
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile

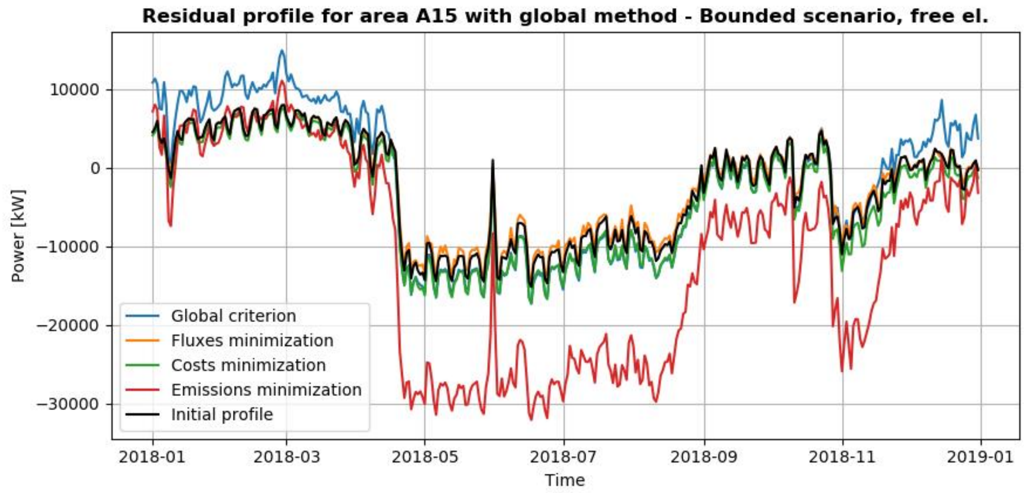

Residual profile for area A10 with global method - Bounded scenario, free el.
Power [kW]
Time
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile

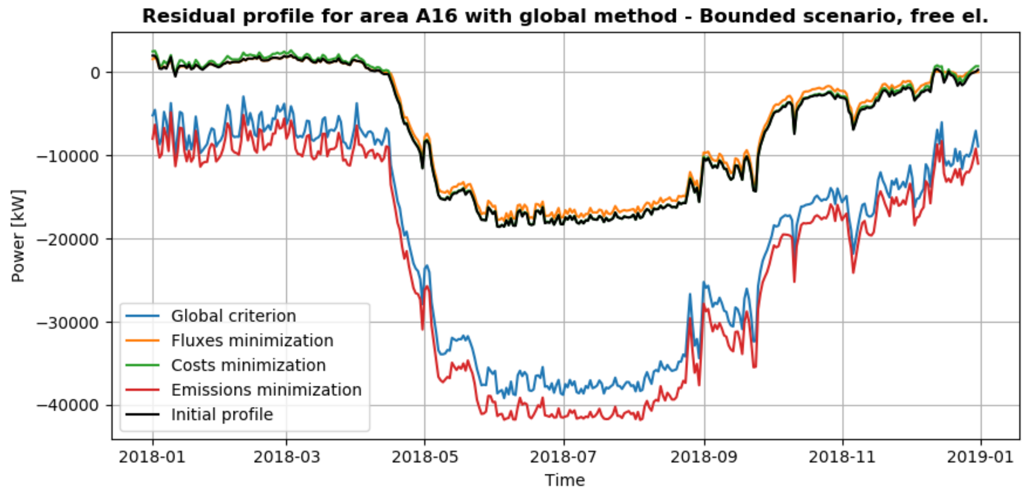

Residual profile for area A11 with global method - Bounded scenario, free el.
Power [kW]
Time
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile

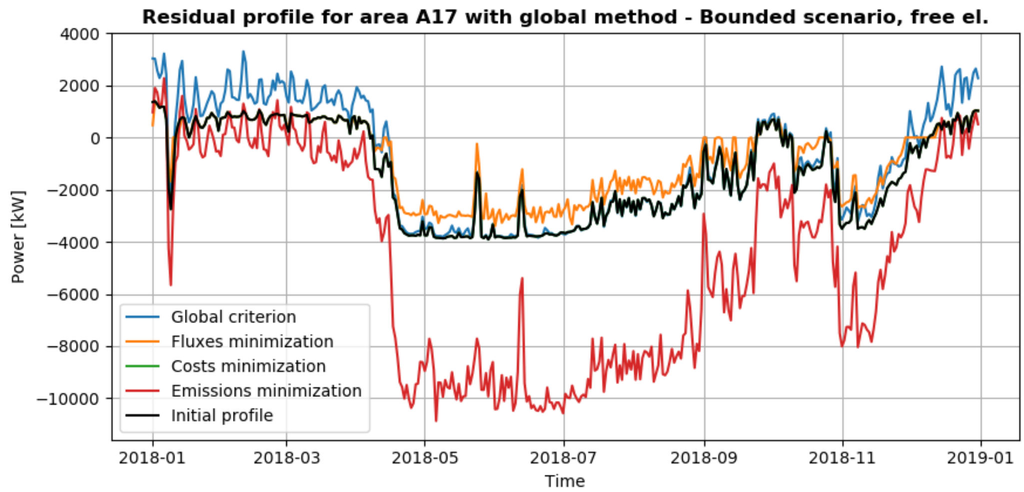

Residual profile for area A12 with global method - Bounded scenario, free el.
Power [kW]
Time
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile


Residual profile for area A13 with global method - Bounded scenario, free el.
Power [kW]
Time
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile


Residual profile for area A14 with global method - Bounded scenario, free el.
Power [kW]
Time
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile

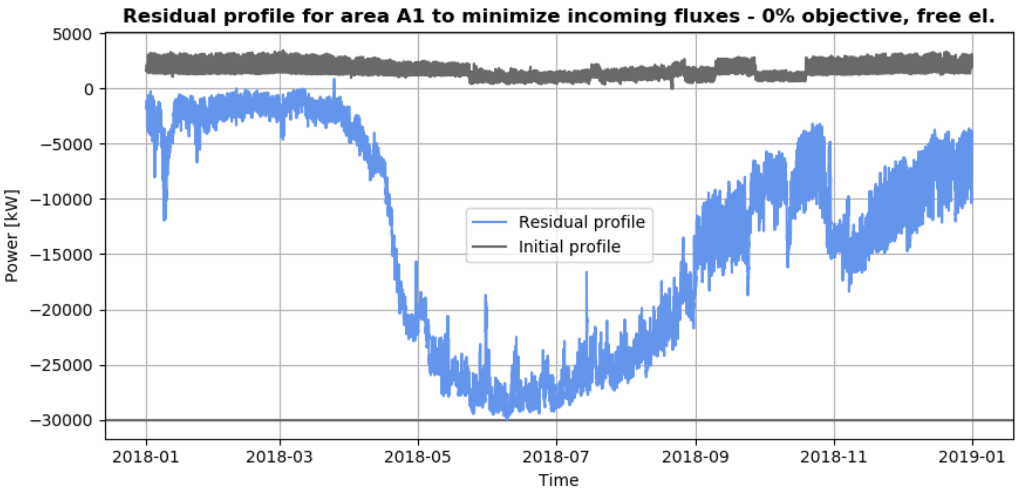

Residual profile for area A15 with global method - Bounded scenario, free el.
10000
0
−10000
−20000
−30000
Power [kW]
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

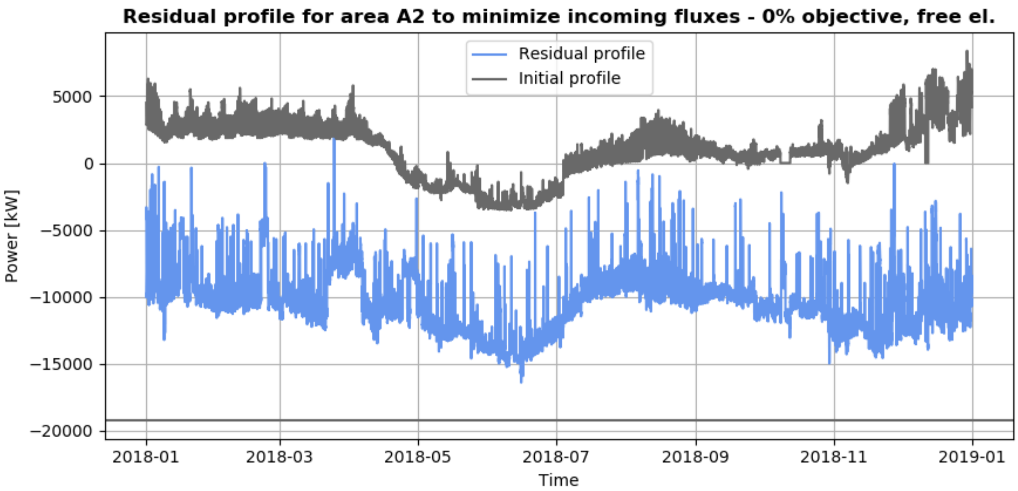

Residual profile for area A16 with global method - Bounded scenario, free el.
0
−10000
−20000
−30000
−40000
Power [kW]
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

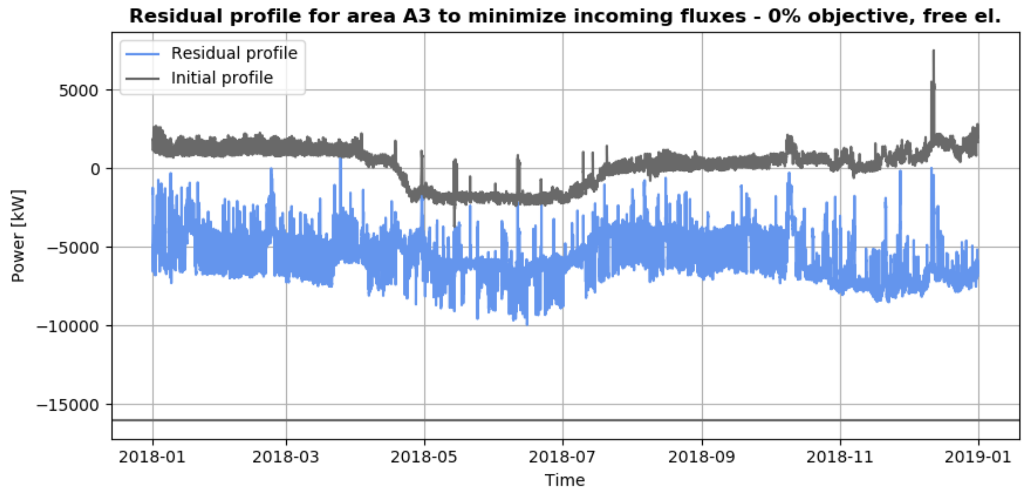

Residual profile for area A17 with global method - Bounded scenario, free el.
4000
2000
0
−2000
−4000
−6000
−8000
−10000
Power [kW]
Global criterion
Fluxes minimization
Costs minimization
Emissions minimization
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

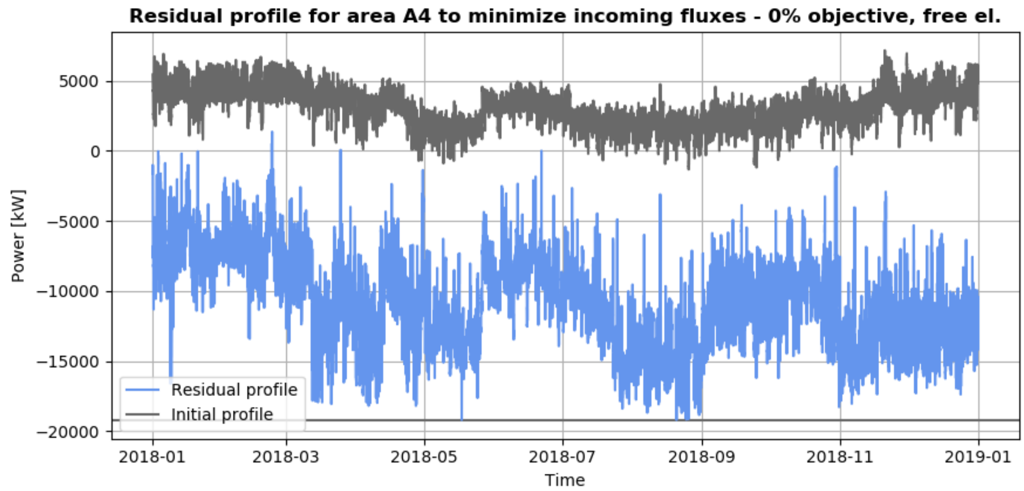
Appendix L – Residual profiles with incoming fluxes minimization in free potential scenario

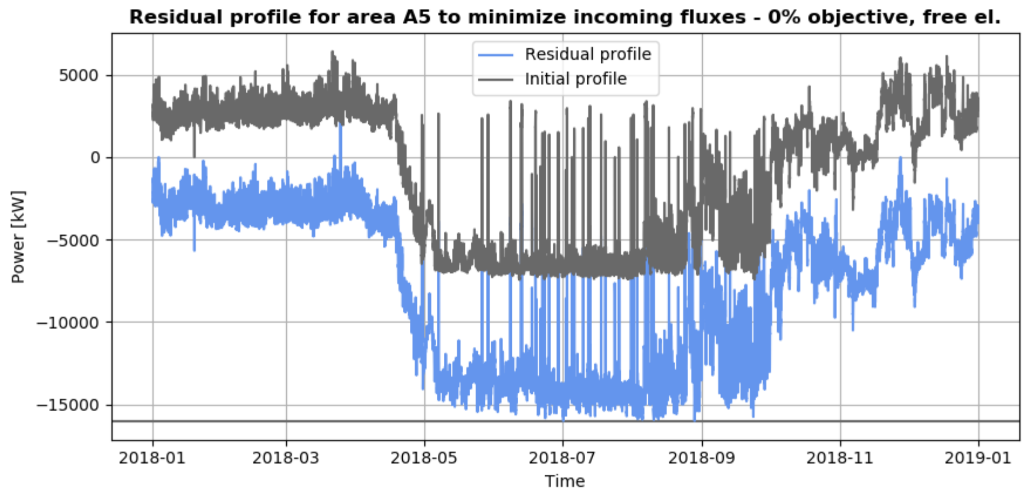
This appendix reports the residual profiles for all areas following the minimization of the incoming fluxes with 0% objective and free electrification (see Chapter 7.3). For clarity, the objective is here defined as the minimization of the overall incoming fluxes $\sum_t Z^+(t)$, with the constraint that the lower bound of the ratio between $\sum_t Z^+(t)$ and $Fluxes_{Tot}$ is 0%.

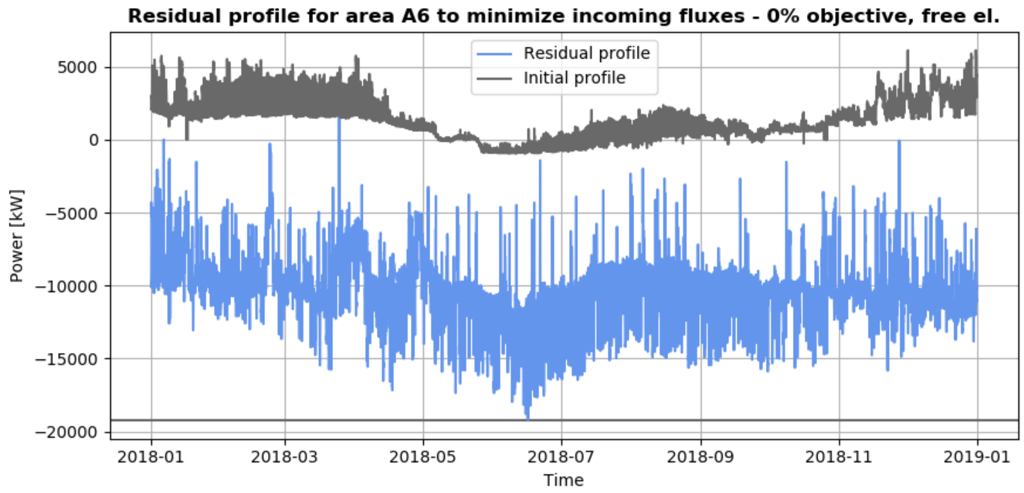


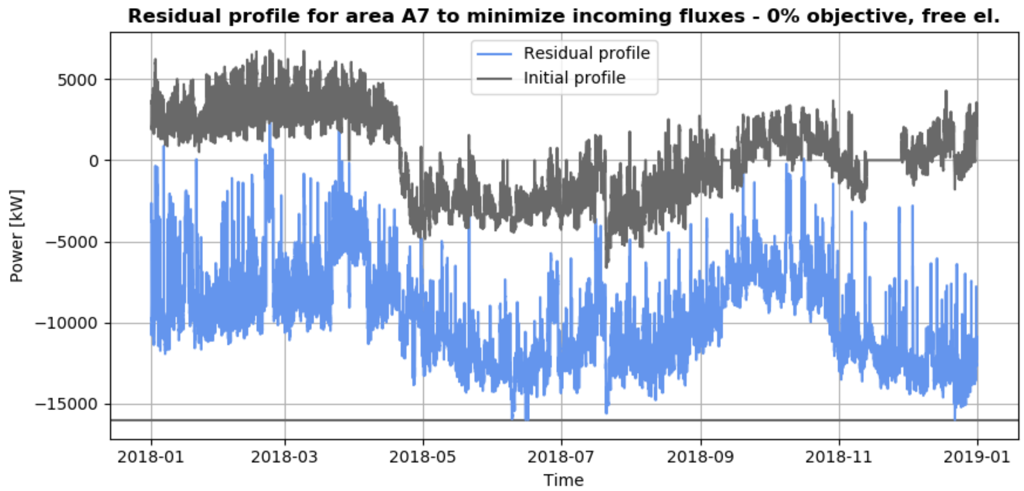


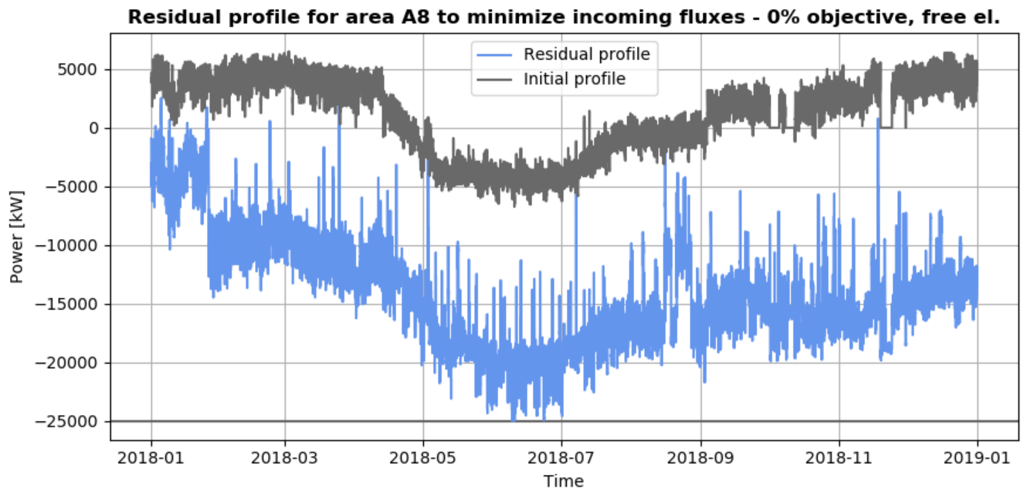

Residual profile for area A3 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
Power [kW]
5000
0
−5000
−10000
−15000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

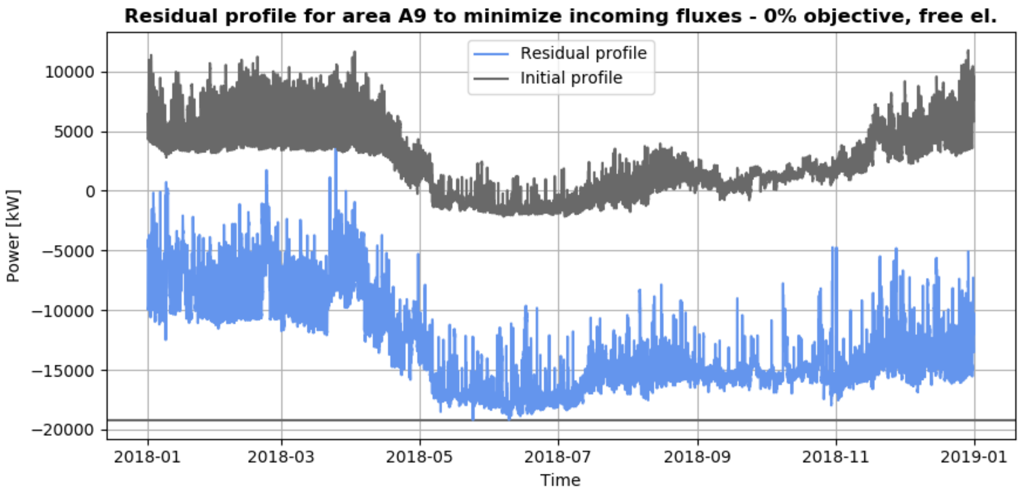

Residual profile for area A4 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
Power [kW]
5000
0
−5000
−10000
−15000
−20000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

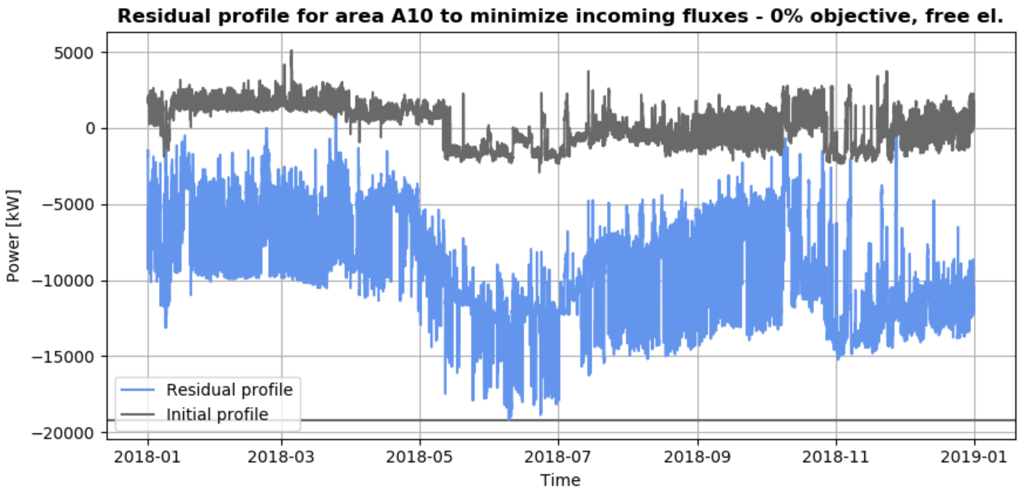

Residual profile for area A5 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
Power [kW]
5000
0
−5000
−10000
−15000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

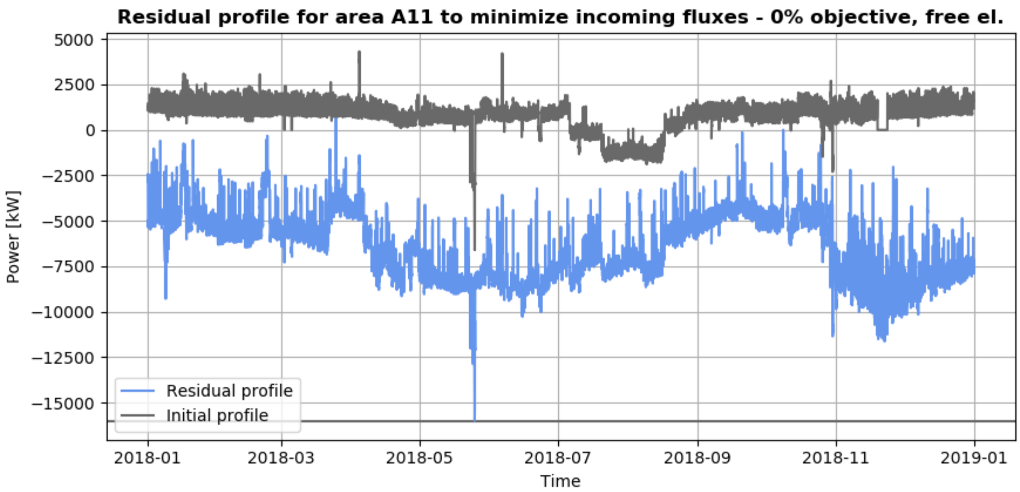

Residual profile for area A6 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
Power [kW]
5000
0
−5000
−10000
−15000
−20000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

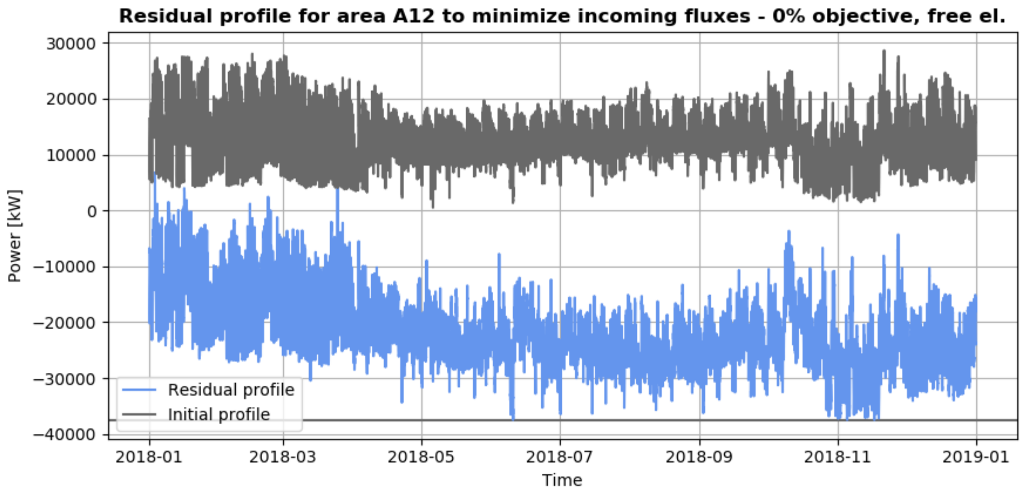

Residual profile for area A7 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
Power [kW]
5000
0
−5000
−10000
−15000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time


Residual profile for area A8 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
Power [kW]
5000
0
−5000
−10000
−15000
−20000
−25000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time


Residual profile for area A9 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
10000
5000
0
−5000
−10000
−15000
−20000
Power [kW]
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time


Residual profile for area A10 to minimize incoming fluxes - 0% objective, free el.
5000
0
−5000
−10000
−15000
−20000
Power [kW]
Residual profile
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time


Residual profile for area A11 to minimize incoming fluxes - 0% objective, free el.
5000
2500
0
−2500
−5000
−7500
−10000
−12500
−15000
Power [kW]
Residual profile
Initial profile
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time


Residual profile for area A12 to minimize incoming fluxes - 0% objective, free el.
Power [kW]
Time
Residual profile
Initial profile
30000
20000
10000
0
−10000
−20000
−30000
−40000
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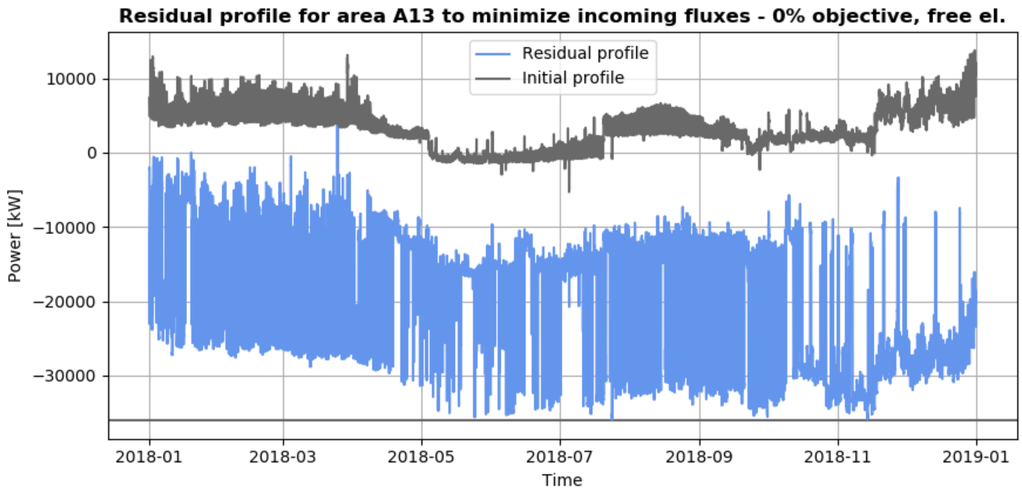
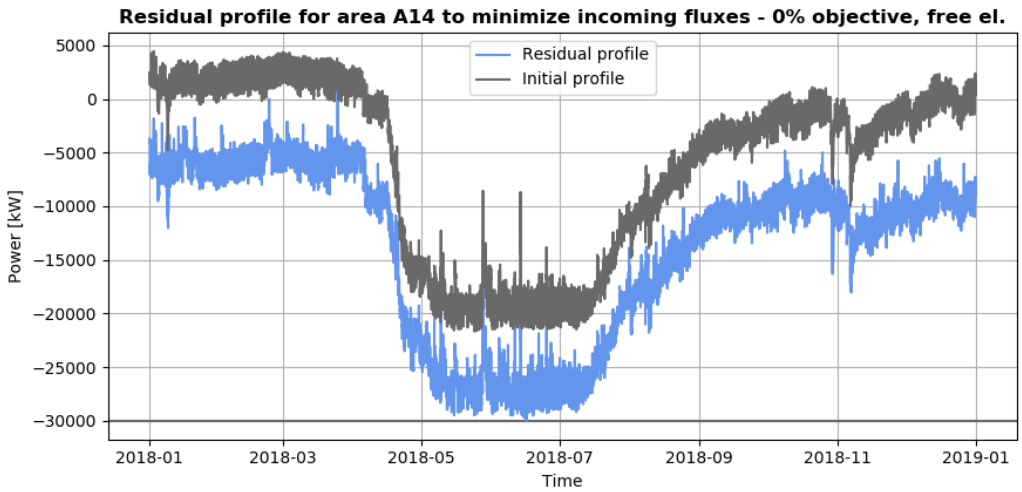
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01


Residual profile for area A13 to minimize incoming fluxes - 0% objective, free el.
Power [kW]
Time
Residual profile
Initial profile
10000
0
−10000
−20000
−30000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01


Residual profile for area A14 to minimize incoming fluxes - 0% objective, free el.
Power [kW]
Time
Residual profile
Initial profile
5000
0
−5000
−10000
−15000
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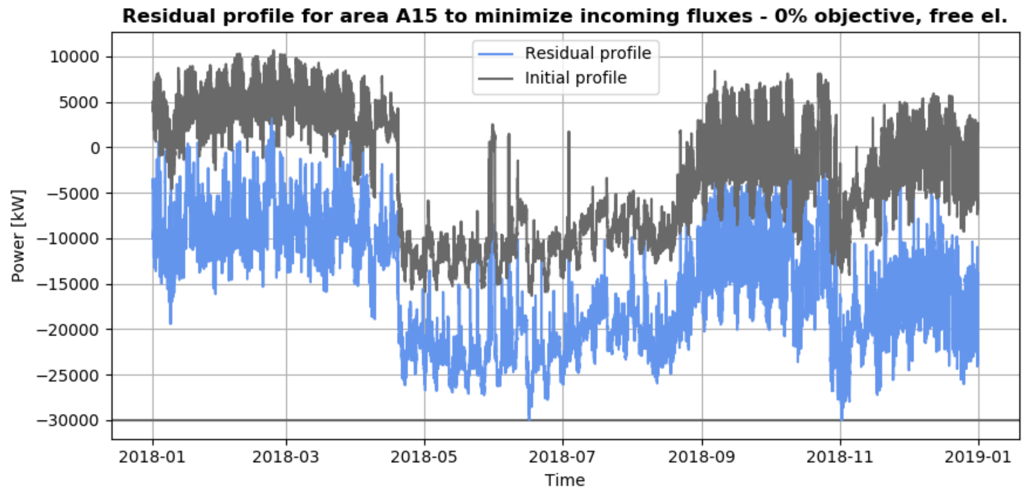
−30000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01


Residual profile for area A15 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
Power [kW]
10000
5000
0
−5000
−10000
−15000
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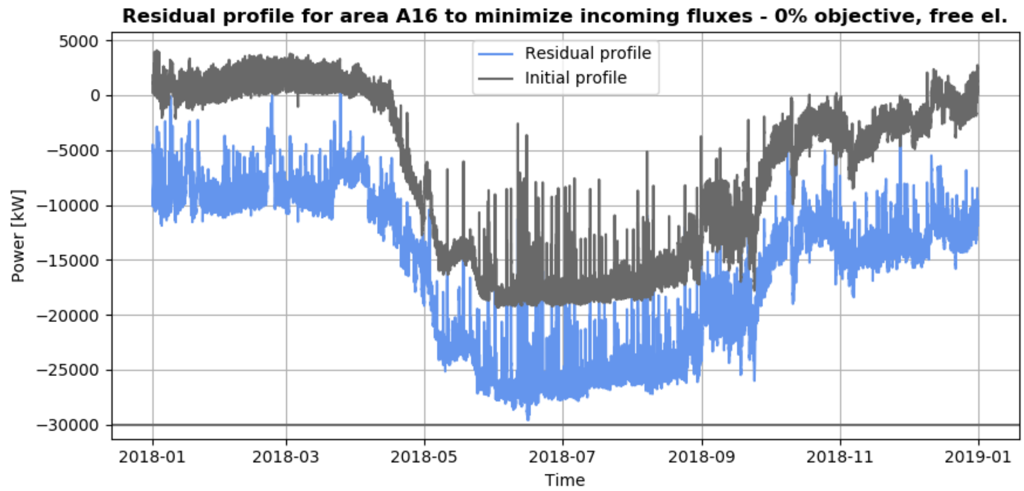
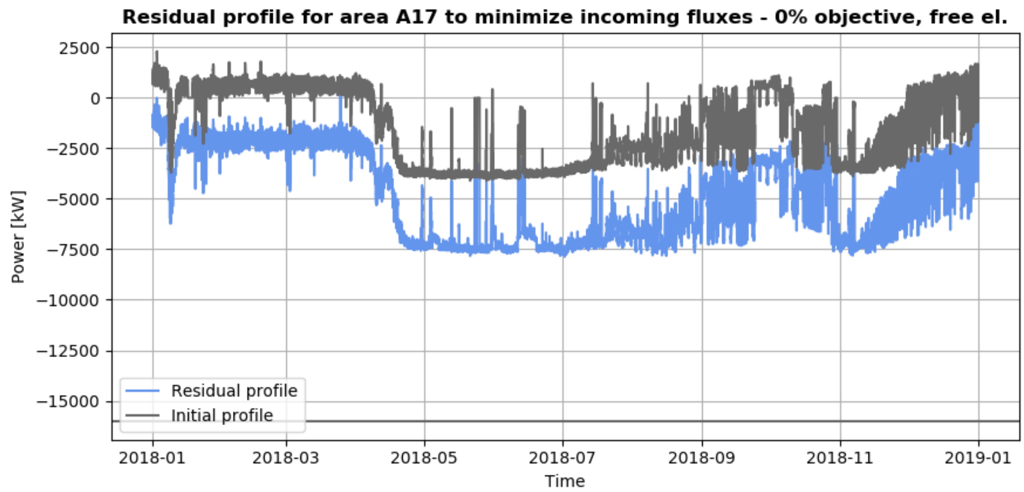
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time


Residual profile for area A16 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
Power [kW]
5000
0
−5000
−10000
−15000
−20000
−25000
−30000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time


Residual profile for area A17 to minimize incoming fluxes - 0% objective, free el.
Residual profile
Initial profile
Power [kW]
2500
0
−2500
−5000
−7500
−10000
−12500
−15000
2018-01
2018-03
2018-05
2018-07
2018-09
2018-11
2019-01
Time

Nomenclature and Acronyms

$ASHP$	Air Source Heat Pump
c_{El}	Cost of electricity consumption
c_i	Specific cost by heating source i
c_j^{Inv}	Specific investment cost of heat pump technology j
c_k^{Inv}	Specific investment cost of generation technology k
$c_{Battery}^{Inv}$	Specific investment cost of battery
$c_{Heat.}$	Specific variable cost of heating
$c_j^{O\&M}$	Specific annual O&M cost of heat pump technology j
$c_k^{O\&M}$	Specific annual O&M cost of generation technology k
$c_{Battery}^{O\&M}$	Specific annual O&M cost of battery
c_k^{Var}	Specific variable cost of generation technology k
$C_{Battery}$	Battery capacity
CEP	Clean Energy Package
CHP	Cogenerative Heat and Power
COP_j	Coefficient of Performance for heat pump technology j
CSP	Concentrated Solar Power
DOD	Depth of Discharge
e_i	CO_2 emissions factor by heating source i
$e_{Grid}^{CO_2}$	Average CO_2 emissions factor by electricity consumption by the grid
$e_k^{CO_2}$	CO_2 emissions factor by source k
$e_{Battery}^{CO_2}$	Specific CO_2 emissions by battery production
$e_{Heating}^{CO_2}$	Average CO_2 emissions factor of heating
e	Annual energy consumption specific to the surface of a household
$Emissions_0$	Minimum possible annual emissions by energy consumption
$E_{Non-electric}$	Annual useful non-electric energy demand for heating
$E_{n,i}$	Annual useful energy demand for heating by source i in municipality n
$E_{Heating}$	Useful energy for heating by household
EE	Electric energy
EV	Electric Vehicles

f	Occupation frequency of a household
$f_{Heating}$	Overall heating electrification
$F_{Battery}$	Net flux by battery
$Fluxes_0$	Minimum possible sum of the absolute values of the fluxes through the transformation primary substation
FM	Multiplication Factor for heating power
g	Group of households
GG	Degree Days
$GSHP$	Ground Source Heat Pump
h	Duration of use
HP	Heat Pump
HV	High Voltage
i	Source of primary energy, discount rate
j	Technology for heating, electricity generation plants
k	Electricity generation technology
L_{EE}	Electric load
$L_{Heating}$	Electric load for heating
LCA	Life Cycle Approach
LP	Linear Programming
LV	Low Voltage
m	Area
$MILP$	Mixed Integer Linear Programming
MV	Medium Voltage
n	Municipality
N	Number of households
NPC	Net Present Cost
NPC_0	Minimum possible NPC by energy consumption
$O\&M$	Operation and Maintenance
p	Construction period
$\overline{p_k}$	Regional average normalized generation profiles of source k
p_k	Normalized generation profiles of source k
p_{Zone}	Zonal price
P	Power or nominal capacity

$P'_{Heating}$	Un-corrected power for heating
$P_{j,k,m}^{Monitored}$	Power output of monitored plant j of source k in area m
$P_{k,m}^{Overall}$	Overall power output of plants of source k in area m
$P_{k,m}^{Normalized}$	Normalized power output of plants of source k in area m
P_m	Useful power for heating of all group of households of all occupation frequencies of all construction periods in area m
P_j	Electric power for heating with technology j
$P_{TR,m}^{nom}$	Transformer nominal power in area m
P_{nom}^{HP}	Average assumed nominal power of the heat pumps
$P_{PV,m}^{Simulated}$	Renewables.ninja-simulated power output by PV in area m
PE_i	Primary Energy by source i
PMI	Piccole e Medie Imprese
$PNIEC$	Piano Nazionale Integrato per Energia e Clima
PUN	Prezzo Unico Nazionale
PV	Photovoltaics
RES	Renewable Energy Sources
RF	Random Factor
S	Average surface of household
SOE	State of Energy
$SMEs$	Small and Medium Enterprises
t	Timestep
t_g	Starting time of use of heating plant for group of households g
T	Temperature profile
T_{ref}	Reference temperature
T'_{ref}	Adjusted reference temperature
TR	Transformer
TSO	Transmission System Operator
VPP	Virtual Power Plant
$V2G$	Vehicle-to-grid
$WSHP$	Water Source Heat Pump
x_j	Fraction of heating demand covered by technology j
x_k	Additional generation capacity by source k
Z^+	Residual positive flux through the transformation primary substation

Z^{-}	Residual negative flux through the transformation primary substation
Δh	Time duration
Δh_g	Duration of use of heating plant for group of households g
ΔT	Temperature difference between reference and outdoor temperatures
α	Weight of fluxes objective in multi-objective optimization
β	Weight of emissions objective in multi-objective optimization
γ	Weight of costs objective in multi-objective optimization
η	Efficiency

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