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To my supervisors,
under whose guidance I have completed this dissertation.

They not only enlightened me with academic knowledge
but also gave me valuable advice whenever I needed it the most.

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Abstract

Europe is currently transitioning from fossil energy sources to renewable generation of electric power. Although fundamental to reach net-zero targets, intermittent *renewables* are disrupting conventional methods used in operational planning and design of processes and the electrical grid. This work focuses on optimal operating strategies in the field of process industries and design of large-scale power systems, with the aim of facilitating the path towards a renewable, robust and intelligent energy system.

The first step requires deep analysis of environmental impact from the electrical grid; therefore, the first development is creation of a novel dynamic *life-cycle assessment*-based (LCA) tool to construct series of impact data from the electrical grid. The tool connects to public databases to quantify the real-time price and environmental impact of electricity consumption. Historical grid impacts and weather data are used to train random forest regressors, which are able to *forecast* week-ahead carbon emissions in each country with hourly granularity. The forecasts are further embedded into a *model predictive controller* (MPC) that optimizes short-term scheduling of an industrial batch process. The method follows a *rolling scheduling* approach that allows for coordination between production scheduling and procurement of electric power targeting minimum environmental impact. The comparison between avoided emissions (5-30% reduction compared to BAU) and resultant operating cost enables calculation of the minimum *carbon tax* that would favour adoption of carbon abatement strategies in industry.

The same use case is used to introduce the second novel concept of representing flexible processes as *equivalent batteries*, which store electricity from low-cost periods as intermediate products and consume the embedded energy during high-cost periods. Cost related to providing flexibility combined with the profits from optimized process scheduling contribute toward monetization of *flexibility* as ancillary services for the grid. Balancing between these services and the cost of implementing *demand-side response* (DSR) solutions creates a seminal pricing strategy for grid flexibility, quantification of which is unprecedented.

Lastly, the work is expanded to focus on design of the future European power system with 100% renewable generation and deep *electrification* of demand. Based on hourly capacity factors of generation, the indispensability of long- and short-term *electricity storage* is demonstrated to increase renewable penetration (+64pp from current) and avoid massive investments in generation overcapacity. Different combinations of storage technologies and generation shares are explored using a Monte Carlo approach with pseudo-random drawing from a Sobol sequence. The comparison between results obtained for independent countries with isolated grids and a single European *interconnected system* shows that electrical synergy can significantly decrease energy cost and total greenhouse gas emissions by 18% and 24%, respectively. Moreover, the same comparison introduces a novel approach to estimate the price that countries should expect to pay for *security of supply*, or their compensation for providing inexpensive renewable energy. Transitioning to renewable-based generation and storage reduces *greenhouse gas emissions* associated with electricity consumption by 90% and prospects a promising 85% reduction in *carbon intensity* of the European economy.

Keywords

real-time; electrical grid; demand side response; model predictive control; equivalent battery; transmission expansion; renewable energy; carbon emissions; carbon tax; grid digitalization

Estratto

L'Europa attualmente sta vivendo una fase di transizione dalle fonti energetiche fossili verso la generazione elettrica da fonti energetiche rinnovabili. Sebbene queste ultime siano fondamentali per raggiungere gli obiettivi di net zero, la loro natura intermittente sta rivoluzionando i metodi convenzionali utilizzati sia nella pianificazione operativa che nella progettazione dei processi industriali e della rete elettrica. Il lavoro di ricerca parte da queste premesse e si concentra sulle strategie operative ottimali in campo industriale e sulla progettazione di sistemi energetici su larga scala con l'obiettivo di facilitare il percorso verso un sistema energetico rinnovabile, robusto ed intelligente.

Il primo passo del lavoro di ricerca consiste in un'analisi approfondita dell'impatto ambientale della rete elettrica; per far ciò è stato necessario principiare lo studio con l'implementazione di un nuovo strumento digitale basato sulla valutazione dinamica del ciclo di vita dell'elettricità. Tale strumento si interfaccia con vari database pubblici per quantificare il prezzo e l'impatto ambientale associati al consumo di energia elettrica. Lo storico dei dati della rete e le misurazioni meteorologiche vengono inseriti in algoritmi di regressione e di apprendimento automatico basati sul modello del random forest. Tali algoritmi sono in grado di prevedere le emissioni di carbonio della settimana a venire con granularità oraria in ciascun Paese europeo. In seguito le previsioni così ottenute vengono inserite in un sistema di controllo predittivo (MPC) capace di ottimizzare la pianificazione a breve termine delle operazioni di un batch process industriale. Il metodo segue un approccio di programmazione con rolling-window che consente il coordinamento tra la pianificazione della produzione e l'approvvigionamento di energia elettrica garantendo il minimo impatto ambientale. Il confronto tra le emissioni evitate (riduzione del 10-20% rispetto al business as usual) e il conseguente costo di esercizio consente di calcolare il valore minimo di una carbon tax che favorirebbe l'adozione di strategie di abbattimento delle emissioni nell'industria.

Lo stesso caso d'uso viene utilizzato per introdurre un secondo concetto innovativo basato sulla rappresentazione di processi industriali flessibili, considerati come "batterie equivalenti", capaci di stoccare elettricità, sotto forma di prodotti intermedi durante i periodi caratterizzati dal basso costo dell'energia, per poi consumarla in periodi ad alto costo. I profitti derivanti dalla pianificazione ottimizzata del processo combinati con i costi relativi alla fornitura di flessibilità contribuiscono alla monetizzazione di quest'ultima come un servizio ausiliari per la rete elettrica. Il bilanciamento tra questi servizi e il costo di implementazione delle soluzioni di partecipazione attiva al mercato della domanda (DSR) permette di introdurre un metodo per la determinazzione del prezzo del servizio di flessibilità, la cui quantificazione non ha precedenti.

Infine il lavoro viene ampliato attraverso la progettazione di un futuro sistema energetico europeo completamente rinnovabile e con elettrificazione della domanda energetica. Sulla base dei fattori di capacità oraria di generazione, viene dimostrata l'indispensabilità dello stoccaggio di energia elettrica a lungo e breve termine per aumentare la penetrazione delle rinnovabili (+64pp dall'attuale valore) ed evitare ingenti investimenti nella sovraccapacità di generazione. Vengono prese in considerazione diverse combinazioni di tecnologie di stoccaggio e quote di generazione attraverso l'utilizzo del metodo Monte Carlo con campionamento pseudo-casuale da una sequenza di Sobol. Il confronto tra i risultati ottenuti per i Paesi indipendenti con reti isolate e quelli ricavati da un sistema europeo interconnesso, mostra che le sinergie elettriche tra i Paesi possono ridurre significativamente il costo energetico e le emissioni di gas serra rispettivamente del 18% e del 24%. Inoltre, lo stesso confronto permette di introdurre un nuovo metodo per stimare il prezzo che ciascun Paese dovrebbe pagare per la sicurezza dell'approvvigionamento elettrico o per quantificare la compensazione attesa per la fornitura di energia rinnovabile a basso costo. In conlusione, la transizione verso un sistema energetico basato sulla generazione e sullo stoccaggio rinnovabili ridurrebbe le emissioni di gas serra associate al consumo di elettricità del 90% e dell'85% l'intensità di carbonio legata all'economia europea.

Parole chiave
tempo reale; rete elettrica; gestione attiva della domanda; controllo predittivo; batteria equivalente; reti elettriche interconnesse; energia rinnovabile; emissioni di anidride carbonica; tassazione sul carbonio; digitalizzazione della rete elettrica

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Acronyms and abbreviations

BAU	Business as usual
CAPEX	Capital expenses
COP	Coefficient of performance
CSS	Carbon capture and storage
DOE	Department Of Energy
DSR	Demand side response
EIA	Energy Information Administration
GDP	Gross domestic product
GHG	Greenhouse gas
GWP	Global warming potential
GWP100a	Global warming potential over 100 years
GWP20a	Global warming potential over 20 years
HP	Heat pump
IHA	International Hydropower Association
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
KPI	Key performance indicator
LASSO	Least absolute shrinkage and selection operator
LCA	Life cycle assessment
LCOE	Levelized cost of electricity
LP	Linear programming
MILP	Mixed-integer linear programming
ML	Machine learning
MOO	Multi-objective optimisation
MPC	Model predictive control
NG	Natural gas
NLP	Non linear programming
NREL	National Renewable Energy Laboratory
OPEX	Operational expenses
P2G	Power-to-gas

PCC	Pearson Correlation Coefficients
PDF	Probability density function
PV	Photovoltaic
RANSAC	Random sample consensus
RE	Renewable energy
RoR	Run of river
SFOE	Swiss Federal Office of Energy
SNG	Synthetic natural gas
SOC	State of charge
TMY	Typical meteorological year
TOTEX	Total expenses
VRE	Variable renewable energy

Introduction

"[...] Omnium enim rerum principia parva sunt,
sed suis progressionibus usa augentur nec sine causa; [...]"
Marcus Tullius Cicero. *De Finibus* 5, 58

Overview

- Context of the work.
- Demand-side response
- Electrification of the energy end-use.
- The role of electricity storage.
- Contributions and novelty.

In OECD countries, approximately 55.3% of electricity generation is derived from fossil fuels (49.5% in EU-28), while renewable and nuclear sources account for 23.8% (28.4% in EU-28) and 17.7% (25.5% in EU-28), respectively [1, 2]. The use of renewable sources for electrical power generation is growing considerably, registering an increase of 7.0% in wind-derived production and 19.8% in solar between 2017 and 2018 [1]. In the same period, the carbon-equivalent intensity of the European grid decreased by 4.9% reaching 293.3 gCO_2-eq. per kWh_{el} consumed. This is attributed to a 2.2 percentage points increase of the renewable share in the European generation mix, that grew from 29.7% in 2017 to 31.9% in 2018 [3].

European countries have agreed to reach carbon neutrality by 2050. This imposes a progressive phasing-out of fossil fuels and simultaneous electrification across all economic sectors, powered by renewable sources. To cope with increasing electricity demand, many countries are implementing policies to promote renewable energy (RE) use, contributing to decarbonising the electricity grid. Transitioning toward a fully renewable energy system calls for a holistic and integrated approach, motivated by the uncertain nature of RE power generation, fluctuating at the millisecond temporal scale.

Demand-side response

Reliable operation of the electricity grid is a fundamental requirement for this transition, but the conventional approach is constantly embattled by developments in variable generation, distribution outages and unexpected load changes [4]. Reliable power systems must guarantee a constant balance between supply and demand, which is achievable by efficient communications and flexible relations between suppliers and consumers [5]. Recently, the allowance of unconventional grid resources such as demand response (DR) [6] contributed to grid balancing and improved the quality of the supplied electric power. Grid customers can benefit from lower wholesale market prices, increased reliability and system security [7], while guaranteeing favorable conditions for the grid operator. Peak load reduction translates to reducing requirements for expensive generation reserves and avoided capacity costs such as need for distribution and transmission infrastructure upgrades [8]. DR techniques based on real-time load shifting can additionally support variable generation [9], fostering the proliferation of distributed renewable energy resources as power generation devices connected to the grid.

Industrial customers can play a major role in reducing demand on request [10] due to their high power consumption and lack of some limitations, e.g. comfort constraints, which restrain the applicability of DR solutions in other sectors such as residential buildings. This type of contingency service is based on contracts between utility and customer, [11] which stipulate payments for load interruption using peak load reduction programs. Attempts have been made by researchers to formulate methods for designing such contracts, starting from the application of non-linear models based on Game Theory [12], to more recent solutions that exploit pool-based mechanisms for market clearing aiming at maximising the social welfare of the participants through reschedulable demand [13–15]. Although providing effective pricing techniques in flexible power systems, such methods do not use realistic models for quantifying consumer marginal costs due to power restrictions.

Electrification of the energy end-use

A transition to a fully renewable system will allow the European Union (EU) and its members to decarbonise the energy system while eliminating the dependency on primary energy import, currently accounting for one-third of the block electricity needs [16]. In its perspectives for 2050 [17], the EU considers a 50% increase in electricity demand, including the electrification of heating (using heat pumps) and mobility, which is supported by the literature [18, 19]. Electrifying new demands is an opportunity to move from fossil fuels to renewable-based systems, but also to promote different storage options that balance the intermittency of the latter. Conceiving and adequately evaluating a large-scale renewable system is only possible using a model that accurately reflects hourly variations [20–23].

The role of electricity storage

Energy storage devices prompt and support the integration of RE. In daily and hourly time scales, short-term storage devices – such as batteries – can accommodate peak fluctuations of RE, by leveraging swift response rates and large power-to-energy ratios [24]. Sepulveda et al.[25] suggested, however, that relying entirely on batteries to boost RE capacity is not a profitable strategy to promote decarbonisation. In the quest for continuous carbon intensity reduction of the electrical grid, and with CO_2 emissions approaching zero, storage oversize promotes a steep increase in the levelized cost of electricity (LCOE), due to the relatively high cost of batteries – reaching hundreds of US dollars per kWh [26] – associated with an inability to dissociate power and energy components. Therefore shifting supply and demand in the monthly or seasonal time-frame cannot be effectively handled exclusively by batteries[25]. The same reasoning is supported by Dowling et al. [27] who assessed the feasibility of fully renewable energy systems using historical US weather data. Different technologies are used depending on the time-scale: batteries are more adequate for hourly and daily storage whereas long-term options, such as power-to-gas (P2G), are used for weekly and monthly storage. Indeed, the combination of short- and long-term storage options is particularly advantageous: batteries have a relatively low power to capacity ratio, while long-term storage options have lower energy-related costs, making them suitable to handle large amounts of energy but not to be used as grid regulators or on-demand technologies. Moreover, long-term storage renders full RE systems more affordable by reducing the need for the oversizing tendencies associated with exclusive short-term systems [27].

The future energy system is a medium- to long-term commitment, in which storage technologies ensure fully dispatchable RE, a crucial feature for ubiquitous adoption. Furthermore, the symbiosis of the different storage options is deemed inevitable to design flexible and robust solutions. Notwithstanding that short-term storage technologies are those receiving the bulk of scientific attention, development and institutional investment [24, 27, 28], the increasing penetration of renewable resources requires systems with greater (weeks to months) discharge time [24, 29] making them more competitive, motivated by the progressive economic reward of grid arbitrage and reliability of supply.

The deployment of high shares of RE is enhanced by a seasonal storage system, which helps to balance supply and demand. There seems to be a lack of awareness of the impacts associated with storage options, particularly concerning the energy system configuration (i.e. the best combination of short- and long-term technologies), operation and economics[24]. To illustrate, Arbabzadeh et al. [30] determined the most profitable storage technology combination for successful renewable penetration. While technologies with lower capital costs (pumped-hydroelectric and compressed air storage) are preferred, the time dimension of storage is disregarded and therefore the associated flexibility; Li-ion batteries, for example, are never deployed, even with ambitious renewable penetration goals and high emission taxes.

Whereas many studies address the design of the future energy system [23, 24, 26, 31], few tackle the required seasonal storage size and operation and use the adequate scale and level of granularity to propose feasible and robust designs at national and continental levels. Besides capital costs, frequently neglected parameters such as the lifetime of storage options or maintenance and operating costs ought not to be disregarded or arbitrarily selected. For instance, as recently demonstrated by Sepulveda et al. [32], discharge efficiency is the key performance parameter affecting the design of storage solutions.

Contributions and novelty

This work focuses on optimal operating strategies in the field of process industries and design of large-scale power systems, with the aim of facilitating the path towards a renewable, robust and intelligent energy system. With the considerable challenges presented for the energy transition, the work addresses the following research questions:

Chapter 1: Real-time carbon accounting and forecast for reduced emissions in grid-connected processes

"How can granular electricity data be used to introduce carbon abatement strategies in industry? What carbon tax would incentivize industries to change operating strategies to reduce their climate change impact?"

Real-time carbon accounting is paramount to promote policies that effectively achieve sustainability goals. A novel real-time carbon tracking tool for the European electricity grid is presented in this chapter. The tool fetches hourly volumes of electricity consumption and generation, power exchanges across country borders and weather data to quantify the real-time environmental impact of electricity consumption with locally-differentiated emission factors of the generation resources. The framework makes use of weather data from several weather stations scattered across Europe to generate week-ahead forecasts of the grid carbon intensity. The predictions are generated by means of a random forest regressor which is further embedded in the optimal controller of a real industrial batch process. The prediction-based optimizer aims at minimizing the total emissions associated with the electricity consumption of the process schedule using a rolling horizon approach. Making use of the process energy flexibility, the controller offers a large potential for load shifting and emission reductions albeit increasing costs. Balancing both enables derivation of a novel methodology for carbon taxation in industry, contributing to carbon abatement strategies to be deployed in industry.

Chapter 2: Industrial flexibility as demand-side response for electrical grid stability

"Can grid-connected processes contribute to grid flexibility?
What is the financial compensation to industrial actors for providing such a service?"

A novel methodology for pricing industrial flexibility as an ancillary service for electrical grids is proposed in this chapter. Such compensation is calculated in terms of service marginal cost per unit of restricted electrical energy and represents the minimum indemnity that would encourage an industrial consumer to participate in grid balancing by load shifting. The service is achieved by implementing a demand-side response strategy that minimizes the incremental cost through reactive response (Fig. 0.0.1). Additionally, the study introduces the concept of industrial processes as flexible storage solutions for demand response with respect to the electrical grid. From the perspective of the electrical grid, the processes can be visualised as a physically-equivalent battery with capacity related to their buffering capability. Application of this method in industry would enable fair negotiation of flexibility contracts, and more broadly to estimate the total potential of grid flexibility service potential in the European industrial sector, and a suitable compensation mechanism.

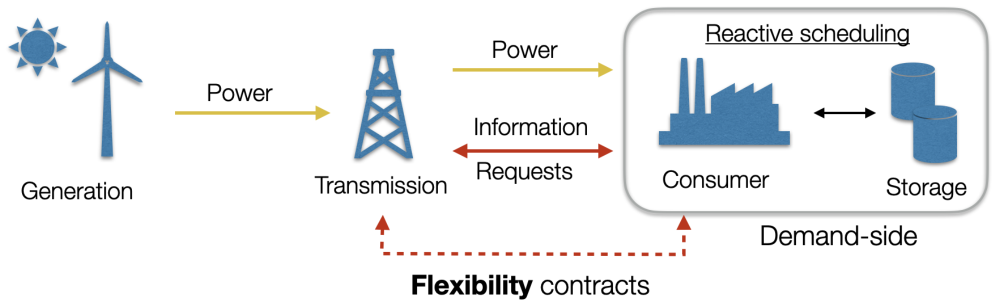

Figure 0.0.1 – Industrial flexibility service scheme.

Chapter 3: The indispensability of electricity storage for a 100% renewable Europe

"What is the role of electricity storage in the future European grid?
Which power sources are more promising when the electrification
of the energy end-use is considered?"

In Chapter 3, the work is expanded to focus on the design of the future European power system with 100% renewable generation and deep demand electrification. All system constraints, such as availability of resources, currently installed capacities and locally-dependent capacity factors are considered to ensure feasible and realistic designs of the European grid. Both isolated and interconnected designs of the energy systems are proposed and compared using economic and environmental metrics. Different types of batteries (lead-acid, lithium-ion, vanadium and zinc flow) and power-to-gas (SNG and Hydrogen) are included to highlight differences among competing technology options that are deemed promising for utility-size energy storage. Overall, the presented work accounts for a large number of variables (i.e. generation shares, storage technology choices, curtailments, interconnections) and metrics, such as frequently overlooked environmental indicators (GWP100a, GWP20a, RE share, ecological footprint, ecological scarcity), to develop a single consistent framework for the design and operation of the European power grids, which constitutes a novelty in literature.

Chapter 4: An incentivized cooperative scheme for transmission expansion in Europe

"How can a grid design based on transmission expansion benefit the European energy system? What is the economic value of the energy security service?"

In the last chapter, the work presented in Chapter 3 is expanded to focus on the aspects of grid interconnection for sustainable electrification. The comparison between results obtained for the isolated grids and the interconnected European system shows that electrical synergy can significantly decrease energy cost and emissions. However, while increased coordination delivers system-wide cost reductions, the economic advantage is unevenly distributed among participants. To this extent, the work introduces a novel approach to estimate the economic value of the energy security service by comparing the reduced LCOE in each country to the uniform price of the shared network. This finding represents the price a country should pay for the security of supply or the expected compensation for granting access to substantial renewable potential. The scheme is based on impartial sharing of the monetary benefits that are obtained by transitioning from an independent design with isolated grids to a full interconnected solution in which Europe acts as a single coordinated entity. Ultimately, the method builds upon the model and results introduced in Chapter 3, hence it implicates a level of detail and data granularity which is unprecedented for Europe.

Real-time carbon accounting and forecasts for reduced emissions in grid-connected processes

1

Why is the real-time carbon tracking of electricity important? What is the environmental benefit of carbon abatement strategies in industry? What carbon tax would incentivize industries to change operating strategies to reduce their climate change impact?

Overview

- Implementation of a tool for real-time electricity carbon tracking.
- Random forest regression algorithm to forecast carbon emissions.
- Model predictive control strategy to achieve optimal operations scheduling with minimal environmental targets in an industrial batch process.
- Estimation of a carbon tax associated with electricity consumption in industry.

This chapter is a preprint version of the article [33] submitted for publication.

The work presented in this chapter focuses on quantifying the benefits achieved by optimal operations scheduling by targeting minimum emissions in industry. First, the implementation of a dynamic life-cycle assessment-based tool able to track the real-time carbon content in the electricity grid is presented. The accuracy of the tool is quantified in terms of relative improvements from current carbon accounting standards by means of bootstrapping technique. Secondly, the same tool is used to train a random forest regressor to forecast the carbon emissions in several European countries with a week-ahead prediction window. The forecasts are subsequently embedded into a model predictive controller that is applied to an industrial use case to minimize the emissions of the weekly production schedule using a rolling-horizon scheduling approach. Thirdly, the comparison between avoided emissions and the increased operating cost allows the calculation of the minimum value for a carbon tax that would spur the adoption of operating strategies aimed at environmental protection in industry.

Introduction

The latest revision of the GHG Protocol outlines guidance for reporting indirect industrial emissions, which are denoted as "scope 2" emissions [34]. This guidance introduced a new "location-based" approach, or "grid average", to address the issue of tracing electricity from the consumption end-use back to the generation source. Such methodology, which is based on the adoption of grid average factors calculated as total emissions from all generation sources divided by the total electricity output over a given period (e.g. one year), represented a significant improvement from earlier standard practices for impact reporting. Moreover, the location-based method offered an effective alternative to the flawed market-based approach which allowed the use of emission factors as contractual agreements between consumers and producers. Brander et al. [35] discussed the limitation of the market-based approach by claiming its inability to affect the amount of renewable electricity being generated, therefore recommending the use of the location-based method to avoid a misrepresentation of responsibility.

Although able to provide relevant GHG information to decision-makers, the location-based method established the use of emission factors that are not specific to the time of consumption. One of the first attempts to improve the temporal resolution was done by Spork et al.[36]. Here, real-time data were used to improve the accuracy of the carbon emissions associated with the purchase of electricity from the grid. The study used the Spanish grid network as a test case and calculated the relative error committed by companies in carbon reporting, which was estimated at 5%. Although improving the temporal granularity of the data, the study was heavily constrained by the system boundaries, which was limited to Spain, consequently neglecting relevant external influences.

Significant improvements in electricity carbon accounting were achieved with the introduction of input-output life-cycle assessment-based (IO-LCA) approaches aimed at eliminating the issue of boundary definition. While essential to make a LCA project manageable, restricted boundaries typically lead to underestimating the true environmental impact, hence resulting in unreliable estimates. IO-LCA approaches improve the impact accuracy by expanding the system boundary, which becomes significantly broader and inclusive. Claus et al.[37] applied such multi-regional logic to quantify the carbon intensity of the electricity consumed in many Scandinavian bidding zones. The study pointed out the importance of cross-border carbon transfers in the calculation of emissions. The same conclusion was achieved by Zhang et al.[38] and Fan et al.[39], which additionally emphasized the need for shifting from production-based to consumption-based accounting mechanisms due to the spatial fragmentation of the production systems. A more detailed consumption-based carbon emission allocation method was proposed by Tranberg et al. [40] The method was applied to hourly market data for several European countries and distinguished between different generation technologies by means of flow tracing techniques. The study identified a significant difference between the carbon intensities associated with production and consumption and concluded by highlighting the importance of real-time carbon measures to lay the foundation for a time-varying electricity tax.

Contributions

A new dynamic life-cycle assessment-based framework to track the real-time carbon content in the electricity grid is developed here. It expands the approach of Tranberg et al. [40] by including ten additional countries in the carbon network and using weather data from more than 200 weather stations throughout Europe to generate week-ahead forecasts of the grid carbon intensity. The predicted emission profile is used as a control signal for the operation of an industrial batch process, used as a case study and simulated in several European countries. Making use of the process energy flexibility, the controller offers a large potential for load shifting and emission reductions while penalising costs. The trade-off arising between avoided emissions and increased costs engenders a novel methodology for carbon taxation in industry.

We demonstrate the importance of grid digitalization that entails creating databases of granular electricity data in space and time. These data can be used to take action towards reducing the environmental impact in numerous energy sectors. Carbon flow tracing techniques for the electricity grid have applications that extend far beyond mere carbon accounting. They can be used to implement effective carbon abatement strategies such as those proposed here for the industrial sector.

1.1 Real-time carbon tracking

The tool uses data provided by the ENTSOE database [3] to quantify the impact of the electricity consumption in each European country. It considers real-time electricity production mixes, electrical power exchanges across borders and locally-differentiated carbon intensities [41] of the energy sources to calculate current or past environmental indicators for each European country with a data granularity of one hour.

The implementation allows interfacing with optimization algorithms in such a way that the data stream indicators can be automatically fed into operation scheduling problems. As a result, the tool provides the basis for carrying out optimization with environmental objectives (i.e. minimization of the carbon footprint associated with production) or, alternatively, it can be used as a postcomputation phase to assess real-time environmental performance of a process by calculating its sustainability indicators.

Overview

The tool runs the following macro processes:

1. **Real-time electricity data acquisition**: Real-time electricity data are fetched from the ENTSO-E database by means of querying routines to the API endpoints.
2. **Data validation:** The data are validated using electricity production limits that are defined by the current installed capacities per resource type and per country.
3. **Environmental indicators calculation**: After validation, the European carbon flow network is solved to calculate the environmental indicators and the results are saved to a persistent database.

Data acquisition

The data fetcher sends queries to the ENTSOE database depending on the selected running mode (i.e. past, current, forecast). This module contains all the parameters, domains and units used to request data from the database and parse the response. It defines the query endpoints of the database API, the IDs of the energy technologies and creates the links between each country (which receive a zone key assignment) and the domain mapping codes used in the query.

The time of the query is always expressed in coordinated universal time (UTC). The time of the response is converted back to local time for usability purposes. The type of queries are: (i) Total electrical power consumption of a country at a specific time in MW; (ii) Electricity production mix of a country in MW; (iii) Total generation forecast of a specified country in MW, usually with a maximum time window of 24 hours (day-ahead); (iv) Electrical power exchange (including day-ahead forecast) across borders between two European countries in MW; (v) Electricity price of a specified country in EUR/MWh.

It should be noted that the fetched data are not always up-to-date since recent data may not have been recorded in the database. The last available data are used in this case.

Data validation

For each country considered in the grid network, non-renewable energy sources (nuclear, coal, gas, oil) are assumed to be part of the mix. The renewable sources are: biomass, hydro (RoR, reservoirs and pumped storage), solar PV, wind (onshore and offshore) and geothermal. An additional category ("other fossil") is added to the mix to account for the electrical energy derived from unknown sources. Its environmental impact is quantified assuming a mix of fossil fuels (coal, gas and oil). However, such term is generally small, often nil, if compared to the other sources in the mix and therefore its impact on the results is almost negligible.

Data retrieved from the ENTSO-E API are validated according to predefined criteria. The validation step is essential to prevent the embedding of inconsistent data, as total production and energy mix information can occasionally be incorrect. For instance, the most common occurrence is when the total production is unexpectedly low and the main generation types of the mix are missing, which results in an unfeasible scenario. To avoid such situations, different validation criteria are implemented and the fetched values are validated and accepted for further calculation only if all criteria are satisfied. If a value fails one of the tests, it is flagged as invalid and subsequently not considered in the calculation. The validation steps are:

1. **Required technologies**: some countries have generation types that must be present in the mix. This validation step checks that such technologies exist and that the corresponding value is not zero. If one of these types is absent, the mix is invalidated.
2. **Expected range**: some production values of certain energy technologies in the mix should always lie within a certain range. If a value falls outside its target range, it is considered as unreliable and therefore invalidated.
3. **Negatives removal**: this criterion checks whether small negative values are present in the mix. If this circumstance is encountered, the value is rejected and therefore discarded from the mix as in the above case.

1.2 Methodology

The carbon intensity arising from the consumption of electricity from the grid in each country is obtained by solving a linear system of equations representing the carbon flows in the European network[40]. The calculated values represent the greenhouse gas footprint of 1 kWh consumed inside a given country. The footprint is measured in gCO_2 equivalent, meaning that each greenhouse gas is converted into its carbon dioxide equivalent in terms of climate change potential.

For each country, i the following balance can be written:

$$D_i = P_i + I_i - E_i \tag{1.1}$$

where D_i is the total electricity demand, P_i is the total production of electricity in country i and I_i and E_i are the total electricity import from other countries and the total export, respectively.

By extending equation 1.1 to the balance equation of the carbon flows of country i,

$$x_i D_i = \sum_r e_{i,r} P_{i,r} + \sum_j x_j I_{i,j} - \sum_k x_i E_{i,k} \tag{1.2}$$

where, x_i is the carbon intensity of the electricity consumption in country i, $e_{i,r}$ is the carbon intensity of resource r in country i, $P_{i,r}$ is the total electricity produced using resource r in country i, x_j is the carbon intensity of the electricity imported from country j, $I_{i,j}$ is the electricity import to country i from country j, $E_{i,k}$ is the electricity export from country i to country k.

Since, from equation 1.1, the term $D_i + E_i$ can be written as $P_i + I_i$, the equation 1.2 reduces to:

$$x_i \big(\sum_r P_{i,r} + \sum_j I_{i,j}\big) = \sum_r e_{i,r} P_{i,r} + \sum_j x_j I_{i,j} \tag{1.3}$$

By considering equation 1.3 and writing it for each country, the following linear system results:

$$\begin{bmatrix} P_1 + I_1 & -I_{1,2} & \dots & -I_{1,n} \\ -I_{2,1} & P_2 + I_2 & \dots & -I_{2,n} \\ \dots & \dots & \dots & \dots \\ -I_{n,1} & -I_{n,2} & \dots & P_n + I_n \end{bmatrix} \times \begin{bmatrix} x_1 \\ \dots \\ \dots \\ x_n \end{bmatrix} = \begin{bmatrix} \sum_r e_{1,r} P_{1,r} \\ \dots \\ \dots \\ \sum_r e_{n,r} P_{n,r} \end{bmatrix} \tag{1.4}$$

where:

$$P_1 = \sum_r P_{1,r} \quad \text{and} \quad I_1 = \sum_j I_{1,j} \tag{1.5}$$

Each country has a CO_2 equivalent emission value that depends not only on its own electricity production mix but also on that of neighbouring countries. To determine carbon footprints, the CO_2 mass flow balance equations of all countries must be addressed simultaneously. This is achieved by solving the linear system of equations defining the network of greenhouse gas productions and exchanges (equation 1.4). The same procedure is adopted to calculate other environmental indicators, such as the Renewable Energy (RE) share, the ecological footprint and ecological scarcity, with the latter two representing the demand on natural capital and the impact on biodiversity, respectively.

Environmental impact factors

The carbon intensities $e_{i,m}$ are location-dependent and specific to each energy resource. Such emission intensities account for the whole life cycle of the electricity production, from plant construction and fuel treating, i.e. including all upstream activities, disposal and decommissioning. The impact of each resource r is calculated using all the technologies m associated with such a resource that are available in the country generation mix ($\mathbf{M}^r$). The impact factors $e_{i,m}$ are calculated by weighting each technology by the corresponding market share s_m [41](equation 1.6).

$$e_{i,r} = \sum_{m}^{\mathbf{M}^r} s_m \times e_{i,m} \tag{1.6}$$

The following generation technologies are considered per resource type:

- **Hydro run-of-river**
  Considers both low-pressure power plants, such as river power stations and canal power plants, and high-pressure run-of-river systems.
- **Hydro water reservoir**
  Differentiates between alpine and non-alpine regions, with the latter being extrapolated from the former. Swiss hydro power plants are taken as a reference. It accounts for all operation and maintenance activities of the power plants.
- **Hydro pumped storage**
  Usually calculated using a representative sample of various dams in Switzerland. It accounts for the impact associated with the use of high-voltage pumped electricity.
- **Solar photovoltaics**
  Accounts for different types of installations, such as slanted-roof, flat-roof, facade (3kWp) and open ground (570kWp). An additional differentiation is introduced between single and multi crystalline types.
- **Wind onshore**
  In-land wind power stations are classified into turbines with capacity lower than 1MW, in between 1 and 3MW and higher than 3MW.
- **Wind offshore**
  Only turbines of capacity comprised between 1 and 2 MW are considered in the offshore category.

- **Biomass**
  Includes heat and power co-generation plant from biogas, which is a mix of different sources (biowaste, sewage sludge), and wood chips from which electricity is produced with an organic ranking cycle equipped with a steam generator.
- **Geothermal**
  Electricity production from deep geothermal power plants.
- **Nuclear**
  Electricity produced from nuclear is divided into two categories depending on the reactor technology. Therefore, pressurised water – both light and heavy water with the first representing the majority of the nuclear installations – and boiling water reactors are considered separately.
- **Coal**
  The power plants of the coal category are differentiated depending on coal sources: hard coal, lignite and peat. Plants based on heat and power co-generation and conventional steam cycle are considered independently. Power plants that use coal gas as combustible are also accounted.
- **Gas**
  Includes combined cycle power plants for heat and power co-generation with size of 400 MW and 100 MW. Conventional power plants and stations fired using by-product gases from industry (i.e. blast furnace gas) are also accounted.
- **Oil**
  Electricity production from conventional oil-fired power plants with and without heat co-generation.

The values of the impact factors $e_{i,r}$ obtained considering all the technologies presented above are shown in appendix A.1. The impact of solar PV is provided in table 1.2.1.

Country	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	1.00	0.76	97.56	113.66	247.13	0.267
Belarus	-	-	-	-	-	-
Belgium	1.00	0.75	101.91	118.83	255.99	0.298
Bosnia and Herz.	-	-	-	-	-	-
Bulgaria	1.00	0.81	71.16	82.90	181.30	0.194
Croatia	1.00	0.82	64.73	75.40	165.11	0.177
Cyprus	1.00	0.84	55.10	64.19	141.06	0.151
Czechia	1.00	0.74	108.00	125.81	273.18	0.295
Denmark	1.00	0.77	91.84	106.98	231.45	0.251
Estonia	-	-	-	-	-	-
Finland	1.00	0.76	95.44	111.16	238.87	0.261
France	1.00	0.79	82.72	96.47	205.40	0.247
Germany	1.00	0.75	100.23	116.88	248.07	0.299
Greece	1.00	0.81	69.69	81.19	177.64	0.190
Hungary	1.00	0.78	85.32	99.38	215.91	0.233
Ireland	1.00	0.80	75.68	88.25	202.10	0.206
Italy	1.00	0.80	73.48	85.81	176.56	0.246
Latvia	-	-	-	-	-	-
Lithuania	1.00	0.75	99.44	115.84	251.73	0.272
Luxembourg	1.00	0.77	91.39	106.45	230.40	0.250
Macedonia	1.00	0.81	68.11	79.35	174.01	0.186
Malta	1.00	0.82	67.52	78.67	174.05	0.184
Montenegro	-	-	-	-	-	-
Netherlands	1.00	0.75	99.33	115.72	251.26	0.273
Norway	-	-	-	-	-	-
Poland	1.00	0.77	90.62	105.57	230.24	0.248
Portugal	1.00	0.83	62.71	73.21	152.93	0.203
Romania	1.00	0.79	80.49	93.76	204.57	0.220
Russia	1.00	0.77	92.46	107.72	235.79	0.253
Serbia	1.00	0.80	75.55	88.01	191.19	0.207
Slovakia	1.00	0.78	82.92	96.60	210.66	0.227
Slovenia	1.00	0.80	76.04	88.59	193.55	0.208
Spain	1.00	0.82	64.77	75.58	159.54	0.202
Sweden	1.00	0.75	100.27	116.83	252.54	0.279
Switzerland	1.00	0.78	85.06	99.14	216.62	0.233
Turkey	1.00	0.82	63.43	73.89	161.62	0.173
Ukraine	1.00	0.78	83.52	97.30	212.11	0.228
United Kingdom	1.00	0.78	84.30	98.44	201.55	0.281
Europe	1.00	0.79	82.53	96.17	208.25	0.233

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table 1.2.1 – Environmental impact factors [41] of electricity generation from solar PV by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

1.3 Accuracy improvement from today's carbon accounting standards

The real-time carbon tracking method achieves a higher level of accuracy compared with current approaches adopted by organisations for carbon accounting activities. The impact factors used in companies' scope 2 accounting and reporting (GHG Protocol Corporate Standard) are typically obtained from the annual production volumes of electricity. A quantification of the potential improvement of using a real-time tracking protocol is shown in Figure 1.3.1, as the mean relative improvement from the annual average for different time scales (hourly, daily, weekly, monthly). The values represent an estimate of the relative error committed by organisations when reporting indirect emissions associated with the electricity purchased from the grid. Since the exact value of the real-time environmental impact is unknown, the indicators provided by the implemented tool are assumed as the true ones.

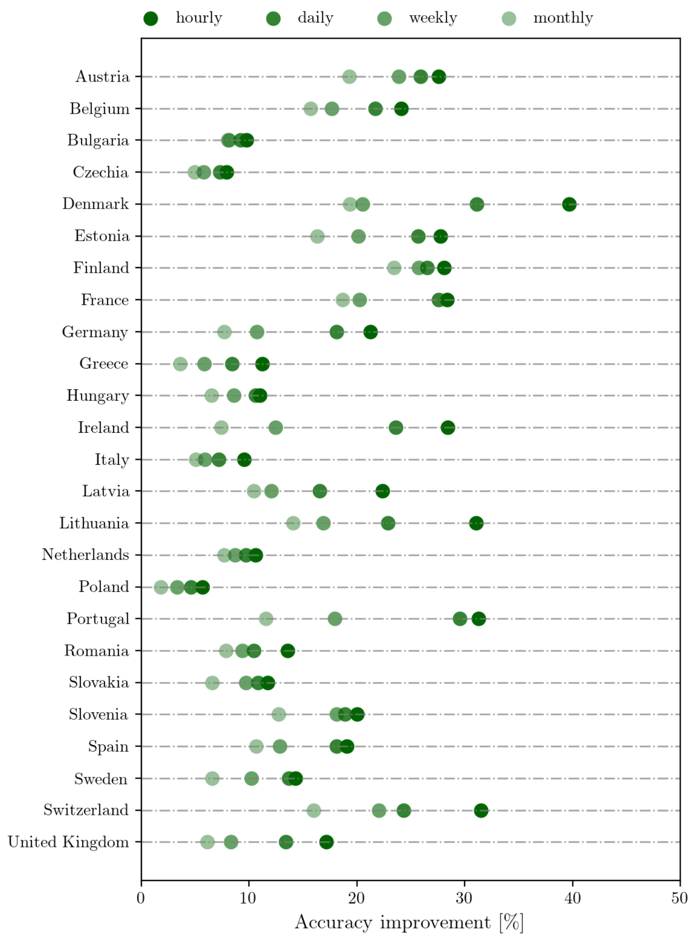

Figure 1.3.1 – Accuracy improvement of the real-time carbon tracking method with respect to today's carbon accounting standards. The plot show the means of the accuracy distributions (relative improvements) tested over different time intervals (hourly, daily, weekly and monthly). The characteristics of the distributions are gathered in tables A.2.1, A.2.2, A.2.3 and A.2.4

The relative improvement is estimated using random sampling with replacement (bootstrapping). Such method allows to approximate the accuracy distribution by sampling from the database of real-time environmental impacts (2019 used as reference year) and by measuring the relative deviation of the samples from the annual average. The sample size is set to 1,000 and the replacement process is repeated 10,000 times. Once the bootstrapping is completed, the accuracy metric is approximated using the constructed distribution.

As demonstrated, the hourly improvement is different in each country and is usually more significant in grids with high renewable penetration of the generated or imported electricity (Fig. 1.3.2). The real-time carbon accounting method brings the least benefit (6%) in Poland (RE share = 15%), where electricity is predominantly produced by base load coal-fired power plants, and the most in Denmark (40%), where the renewable penetration (66%) is currently the highest in Europe. As a result, the accuracy improvement is strictly connected to the variability of generation, which is substantial when renewables are the main source of electricity. The adoption of real-time carbon accounting techniques, such as the one presented in this work, is crucial for the correct estimation of indirect emissions in highly renewable grids, with the role of such grids being deemed essential in the path towards a decarbonized Europe.

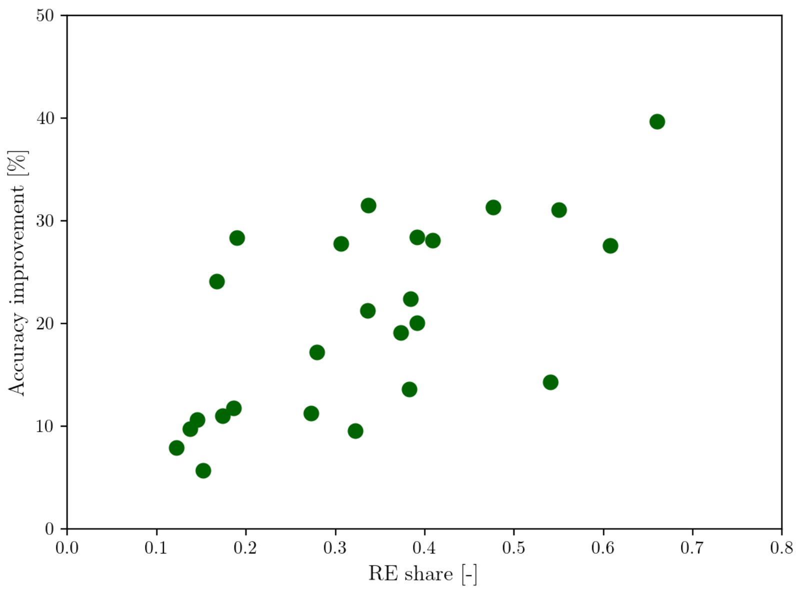

Figure 1.3.2 – Accuracy improvement [%] of the real-time carbon tracking method as a function of the RE share [-] by country.

1

1.4 Carbon emissions forecasting

The framework is able to generate predictions for the day-ahead and week-ahead equivalent carbon emissions profile. It uses information about the total forecasted generation, consumption, output from solar and wind, flow of imports, exports and electricity price (day-ahead spot market), all of which are gathered from the ENTSO-E database. Since the ENTSO-E does not provide forecasts longer than a day, an interface to the Visual Crossing API [42] is implemented to extend the predictions up to the week ahead. Weather information about wind speed and direction, temperature, precipitation and cloud cover are retrieved from more than 200 weather stations scattered across Europe and added to the dataset.

Feature selection

The number of the input variables is reduced to limit the computational cost of the predictive model. A statistical-based feature selection method is implemented to evaluate the relationship between each input variable and the target, namely the equivalent carbon emissions. The method consists of constructing the normalised covariance matrix of the features over a time period ranging between 1 and 3 years, based on the calculation of the Pearson Correlation Coefficients (PCC) which measures the strength of the linear correlations in the dataset. An example result is included in Fig. 1.4.1. The method makes it possible to identify features that are either redundant or irrelevant, and which can therefore be removed from the dataset without significant information loss. Indeed, when a strong linear correlation is found between two features, one can be considered redundant since the correlated one carries the same information. Conversely, when a feature is poorly correlated with the target variable it is interpreted as irrelevant and therefore excluded from the dataset.

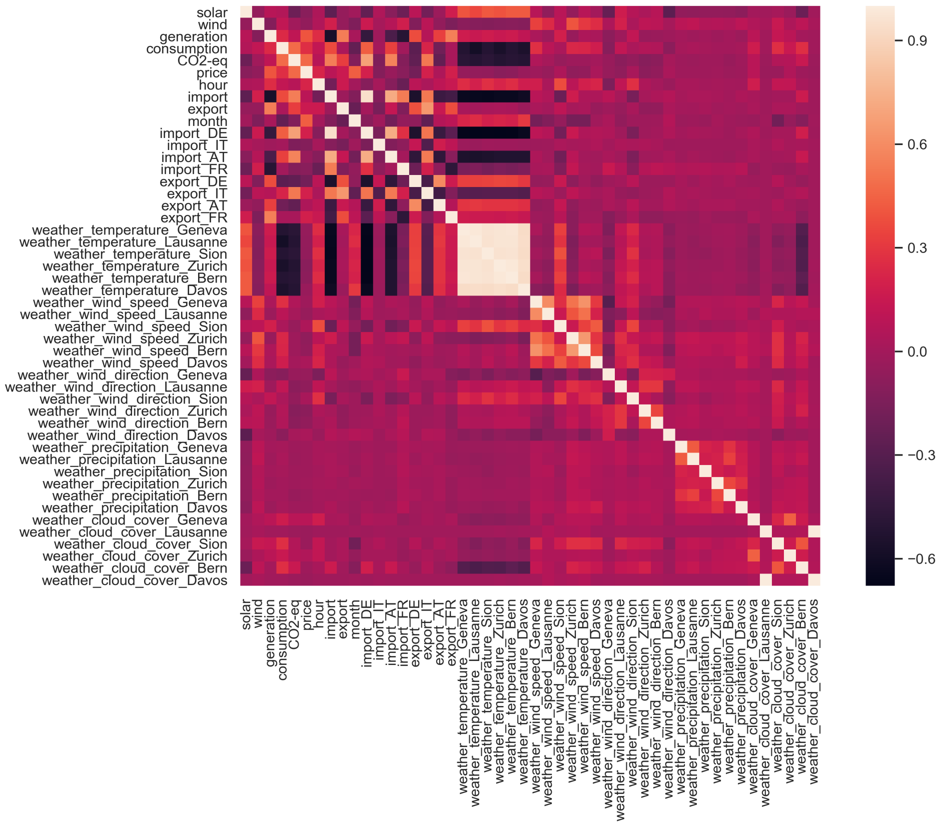

Figure 1.4.1 – Normalised covariance matrix for feature selection. The matrix is constructed by calculating the Pearson correlation coefficients to quantify the linear correlation between the features. In the example (Switzerland) a total of 48 features are considered, including information about electricity price, flow of imports and exports, weather data in different locations and the expected output from solar and wind resources. The normalized coefficients range between -1 and 1, with the first indicating a perfect linear negative correlation and the second a perfect positive correlation. As demonstrated, a significant negative correlation (PCC < -0.6) is detected between the external air temperature in the selected locations (Geneve, Lausanne, Sion, Zurich, Bern, Davos) and the grid carbon intensity (CO_2eq in the matrix).

Prediction algorithms

Since the feature selection can result in the removal of many features from the dataset – occasionally even the use of two features is acceptable – several learning algorithms are implemented, including less sophisticated ones. Simple linear regressions based on the gradient descent (batch) and stochastic gradient descent methods for the minimisation of the learning error were tested. LASSO [43] (least absolute shrinkage and selection operator) and Ridge regression [44] algorithms for L1 and L2 regularisation, respectively, and a combination of the two (Elastic Net regression [45]) were also considered to reduce the risk of over-fitting. Moreover, a multivariate polynomial regression was tested to model possible non-linear relations between the features and the response, and a

RANSAC (RANdom SAmple Consensus) [46] algorithm to detect outliers in the dataset.

All the discussed algorithms are investigated to potentially avoid complex solutions. However, the simplicity of these methods usually leads to insufficient prediction accuracy, or, oftentimes, they are inapplicable due to the irreducibility of a high dimensional feature set. For these reasons, advanced learning algorithms based on artificial neural networks (e.g. Multi-layer Perception [47], Dense neural network) and random forests [48] are implemented and tested. Although requiring higher computational cost, such methods guarantee greater precision with little need for data pre-processing (e.g. data re-scaling and transformation) and parameter configuration. Overall, the random forest is selected as the best performing algorithm; hence it is used to generate predictions. This regression method is able to handle high-dimensional data and it is robust to feature outliers. A hyperparameter tuning mechanism – based on the combinatorial testing of the parameters that are critical to reduce over-fitting – is used to find the optimal number of estimator trees [49], the maximum depth of the trees and the number of samples required at each leaf.

Emissions forecast with Random Forest

The random forest regressor is trained over the emissions database which is split between train and test sets. This algorithm usually achieves high predictive accuracy but suffers from over-fitting. As a consequence, the size of the dataset must be rationally chosen to avoid unnecessary high performance on the training set and poor predictions on unseen data. An excessively large dataset might lead to a model that is too closely representative of past grid configurations and therefore unreliable when used on future observations – with grid configuration changing over time due to increasing renewable technologies deployment. Conversely, a very small sample size does not allow the model to adequately capture the real underlying structures of the electricity grid, leading to an algorithm that may fail to fit additional data. For this reason, the training set is chosen by testing different sample sizes, with 1 or 2 years of data (closest as possible to the prediction window) being generally sufficient to maximise the prediction accuracy.

Fig. 1.4.2 shows an example of a week-ahead prediction (from the 1^{st} to the 7^{th} of January 2019) of the CO_2 content in the electricity consumed in Germany. The mean absolute error (MAE) and the coefficient of determination (R^2) are the metrics used to evaluate the suitability of the model. As demonstrated, the predictive model reproduces the trend of the electricity carbon intensity with satisfactory precision (R^2 = 0.860).

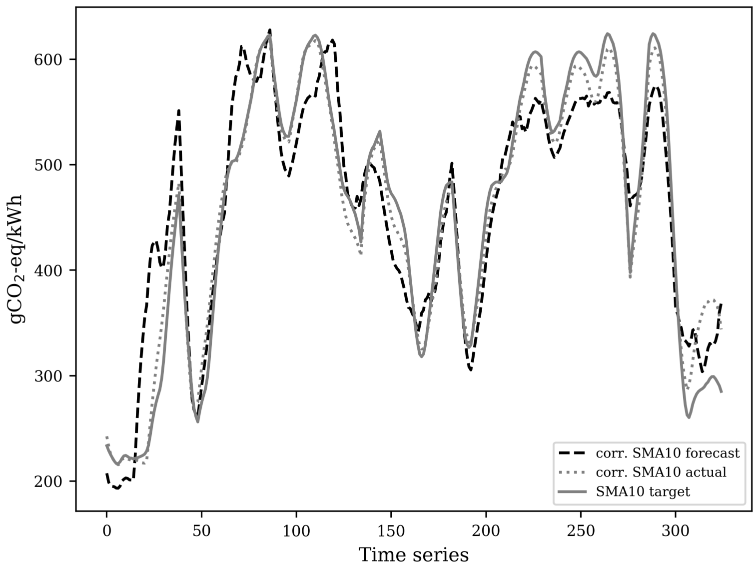

Figure 1.4.2 – Analysis of the week-ahead (from the 1^{st} to the 7^{th} of January 2019) prediction trend in Germany. The figure shows the prediction obtained by using a random forest regressor trained over two years of data (2017 and 2018). The simple moving average (SMA10) is used to quantify how well the model predicts the trend of the target variable. The curve labelled as 'actual' refers to the prediction obtained by applying the model to the actual features. **Arithmetic mean:** 452.4 (target), 465.9 (actual), 500.8 (forecast). **Standard deviation:** 135.7 (target), 125.1 (actual), 123.3 (forecast). **MAE:** 19.4 (actual), 14.3 (actual trend), 54.9 (forecast), 36.9 (forecast trend). **R^2:** 0.952 (actual), 0.971 (actual trend), 0.728 (forecast), 0.860 (forecast trend).

1.5 Application to the case study

A prediction-based optimizer with a weekly time horizon (168 hours) is applied to an industrial batch process and simulated over one month with hourly shifts of the rolling window. A scheduling model is embedded in the predictive controller using a mixed-integer linear programming (MILP) formulation, which is solved at each iteration of the algorithm. The detailed description of the use case is included in Section 2.2, together with all modelling equations. The only difference in this application is that the optimizer aims at minimizing the total emissions associated with the electricity consumption of the production schedule rather than costs. The objective function is therefore reformulated and the scheduling window is extended from 72 to 504 time slots for the weekly scenario – the duration of each time interval is 20 minutes.

1.5.1 Rolling scheduling algorithm with MPC

The predictive controller optimizes the process schedule on an hourly basis. At each iteration, the controller queries electricity and weather data from the ENTSO-E and the Visual Crossing API, respectively (Fig. 1.5.1). The fetched data are subsequently fed to the random forest regressor to update the carbon intensity predictions. The optimization problem is then solved to schedule the operations in each production line with minimum environmental target. At the end of each hour the iteration counter i is incremented and the procedure is repeated until the end of the month (N = 720).

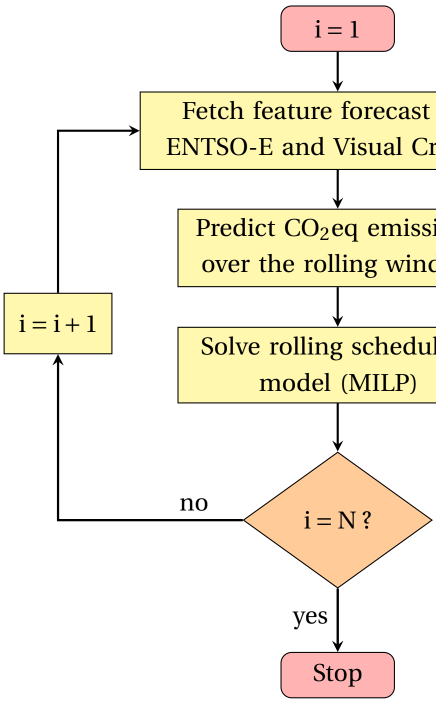

Figure 1.5.1 – Flow diagram of the on-line scheduling algorithm with MPC approach.

1.5.2 Emission improvements in a batch process

Fig. 1.5.2 shows the cumulative average emission profiles associated with two different rolling schedules. In the first scenario (process 1d) the emissions of the process are minimized using day-ahead predictions of the grid carbon intensity. In this case the rolling window is limited to 24 hours and the schedule is unable to see possible favorable conditions beyond this horizon. The process emissions are reduced by 11.6% relative to BAU (grid average in red) and the RE share of the consumed electricity is increased by 6.9pp over the simulated month (Fig. 1.5.3).

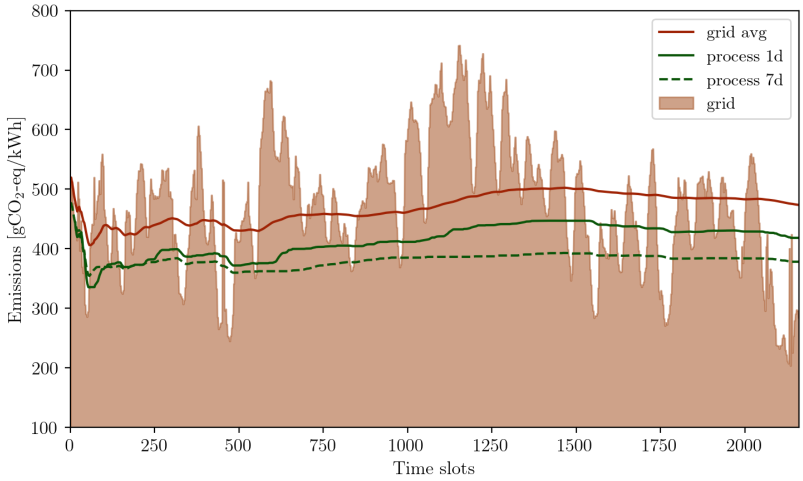

Figure 1.5.2 – Cumulative average emission profile of the MPC applied to an industrial batch process in Germany. The emissions associated to the process are shown for both day-ahead (solid green line) and week-ahead predictions (dashed green line) of the carbon intensity of the purchased electricity. The shaded area refers to the hourly grid intensity while the red line shows the emission associated with production schedule that is unaware of the grid (BAU scenario).

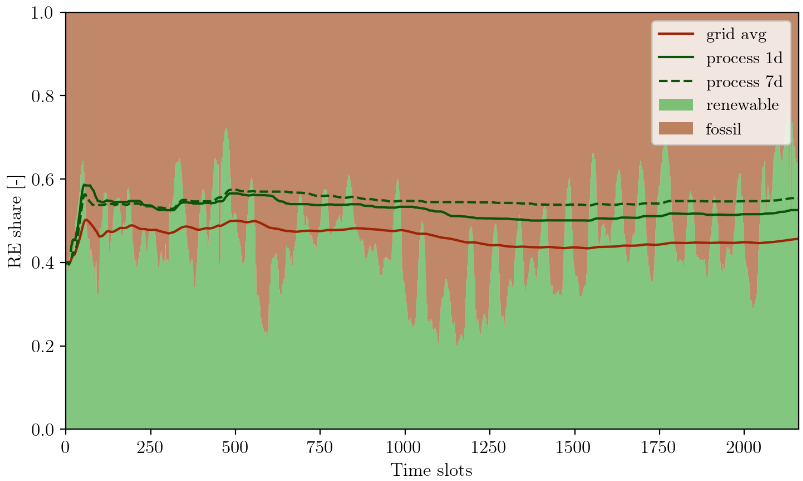

Figure 1.5.3 – Cumulative average renewable share of the MPC applied to an industrial batch process in Germany. Comparison between production schedules with 1-day and 7-day prediction window.

A more substantial reduction in emissions is achieved when the predictions are extended up to one week ahead. In this case, the optimizer has augmented knowledge of future conditions and is therefore able to schedule operations more effectively. The long schedule significantly outperforms the short one during periods of sustained high carbon intensity in the grid (e.g. time slots between

1000 and 1500). In such periods, while the short-term controller schedules the operations with marginal gain with respect to BAU, the longer one is able to identify favourable conditions for production much further in the future. Such knowledge allows the controller to minimize the electricity consumption during high emissions periods by moving energy-intensive operations to the favourable time slots as much as possible. As a result, the CO_2 emissions of the process are reduced by 17.5% relative to BAU (-6.6% relative to 1d scenario) and the RE share increases by 9.7pp (+2.8pp relative to 1d scenario).

Benefits of optimal operations scheduling with emission targets in Europe

The process is simulated in different European countries for both the 1-day and 7-day prediction windows. As shown in Tab. 1.5.1, the improvements in the process carbon emissions vary significantly between countries. Substantial environmental benefits are typically achieved in countries with high RE share in the consumed electricity, such as in Denmark (-28.6%) and Lithuania (-32.4%), while minor improvements are obtained in countries where the electricity is mainly produced from fossil sources, such as in Czechia (-9.2%) and Poland (-4.4%). This effect is due to strong variability in the carbon intensity of highly renewable grids. Under such conditions, long-term planning makes it possible to schedule operations more effectively, leading to larger improvements compared to fossil-based energy systems where the grid carbon intensity is almost constant throughout the day. Overall, the country-weighted reduction in carbon emissions and the RE share increase are -15% and +6.2pp, respectively.

	Grid		Process 1d		Process 7d		
Country	Emissions [gCO_2eq/kWh]	RE share [%]	Emissions [gCO_2eq/kWh]	RE share [%]	Emissions [gCO_2eq/kWh]	RE share [%]	Emission reduction
Austria	271.1	60.8	253.8	63.2	235.6	65.0	-13.1%
Czechia	763.5	12.2	731.2	15.3	692.8	17.1	-9.2%
Denmark	207.0	66.0	180.4	69.0	147.8	73.6	-28.6%
Estonia	583.0	30.6	567.5	32.0	517.1	34.4	-11.3%
Finland	191.7	40.9	181.3	41.9	172.5	43.1	-10.0%
Germany	473.5	45.7	418.4	52.6	390.6	55.4	-17.5%
Greece	666.0	27.2	614.3	34.9	523.5	40.8	-21.4%
Italy	382.9	32.2	358.9	35.8	334.7	39.9	-12.6%
Lithuania	227.9	55.0	189.3	58.7	154.1	62.0	-32.4%
Poland	947.4	15.2	925.4	16.3	905.3	18.3	-4.4%
Spain	232.5	37.3	215.6	39.4	201.3	41.1	-13.4%
Sweden	37.4	54.0	34.1	57.2	30.8	60.6	-17.7%
United Kingdom	270.8	28.0	248.3	29.2	203.1	31.8	-25.0%

Table 1.5.1 – Results of the MPC simulations by country. The performance of the MPC is assessed in terms of emission reduction and RE share increase for both the short- (daily) and long-term (weekly) optimizers.

1.6 Carbon tax

The environmental benefits achieved by operations scheduling with minimum emissions penalises the costs associated with production. Indeed, the proposed operating strategy leads to higher costs compared to a rolling mechanism that maximises consumption during periods of low electricity price. Such cost variation is quantified by comparing the implemented strategy with a similar algorithm that optimises production costs rather than emissions (see Section 2.2).

$$\textbf{Carbon tax} = \frac{\Delta Cost}{\Delta Emissions} \left[\frac{\text{EUR}}{\text{tCO}_2\text{eq}}\right] \tag{1.7}$$

The comparison between the reduced carbon emissions and increased operating cost allows for calculating the value of a carbon tax in industry (equation 1.7). This tax represents the minimum cost that should be associated with emissions to engage industries in operating strategies aimed at environmental protection. Any value below this threshold would result in increased cost of production, therefore making the proposed strategy economically unfavourable for the industry. Conversely, a carbon tax higher than the calculated value would boost the economic competitiveness of low-carbon operations which allow curbing of CO_2 emissions while reducing the overall cost of production.

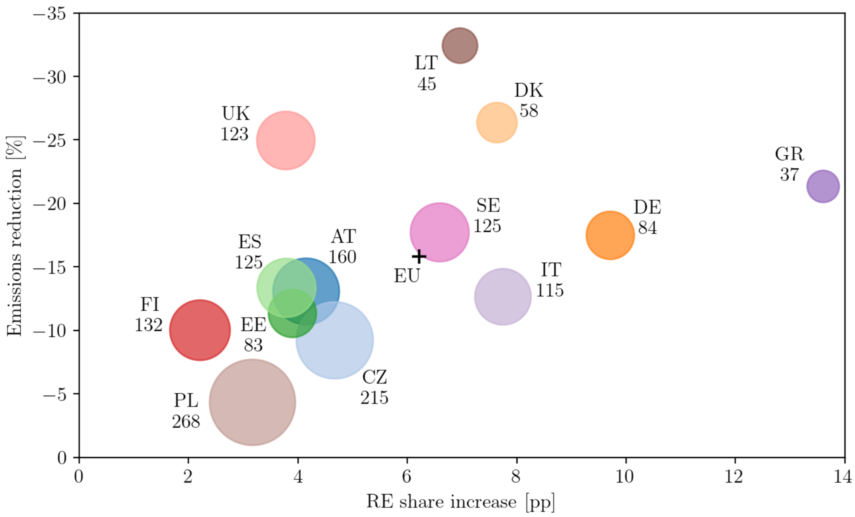

Figure 1.6.1 – Estimated carbon tax for indirect emissions in industry. The values of the carbon tax are denoted by the size of the bubbles and given in Euro per ton of CO_2 equivalent emitted due to electricity consumption.

The results of the calculations are presented in Fig. 1.6.1. The value of the carbon tax is usually higher in countries where the optimal environmental scheduling brings marginal benefits, while it is lower when the reduction in emissions is more significant. However, it is worth noting that the absolute grid intensity can substantially influence the value of the carbon tax. This is the case for Sweden where the presence of clean electricity in the grid drives the tax towards higher values.

1.7 Conclusions

In this chapter, a new real-time carbon tracing method for the electricity grid is presented, using hourly volumes of electricity consumption and generation, power exchanges across country borders and weather data to quantify the real-time environmental impact of electricity consumption with locally-differentiated emissions factors of the generation resources. The method achieves a high level of accuracy in the impact calculation with respect to current approaches commonly adopted by organisations for carbon accounting activities. A quantification of such improvement was included by using random sampling with replacement (bootstrapping) over different time scales (hourly, daily, weekly, monthly). As demonstrated, the hourly improvement ranges between 6% (Poland) and 40% (Denmark) and is more significant in grids with high renewable penetration.

An additional implemented feature is the ability to generate predictions for the day-ahead and week-ahead equivalent carbon emissions of the grid. These are based on the forecasted generation and consumption volumes, solar and wind outputs, flow of imports and exports, electricity price and weather data obtained from the ENTSO-E and Visual Crossing APIs. To reduce the computational cost of the predictive model, a statistical-based feature selection algorithm is implemented. It consists of constructing the normalised covariance matrix to measure the strength of the linear correlations between features by means of the Pearson Correlation Coefficients. Those that are found to be either redundant or irrelevant are removed from the dataset without significant loss of information.

Several carbon prediction algorithms based on a supervised learning approach are discussed, ranging from simple linear regressors and multivariate polynomial interpolators to more complex solutions such as artificial neural networks and random forests. The latter is found to be the best performing algorithm, hence chosen for further predictions. A hyperparameter tuning mechanism based on the combinatorial testing of the model parameters is used to reduce over-fitting, which is often critical in learning algorithms based on decision trees. Moreover, the random forest was found to be sensitive to sample size, with either excessively large or small training sets leading to poor predictions. A predictive model trained over one or two years of data closest to the prediction window was able to reproduce the trend of the electricity carbon intensity with adequate accuracy ($R^2 = 0.860$).

The random forest is subsequently embedded in the optimal controller of a real industrial batch process located in Germany. The prediction-based optimizer aims at minimizing the total emissions associated with the electricity consumption of the process schedule in a rolling window approach. The scheduling problem is modelled using a mixed-integer linear programming (MILP) formulation with weekly time horizon. The process emissions are reduced by 17.5% and the RE share increases by 9.7pp both relative to BAU. The process is also simulated in different European countries. Substantial environmental benefits are typically achieved in countries with high RE share in the consumed electricity (-32.4%), while little improvements are obtained in countries where electricity is mainly produced from fossil sources (-4.4%).

The comparison between the reduced carbon emissions and increased operating cost introduces a novel approach for the calculation of a carbon tax in industry. This value represents the minimum emissions cost that may contribute to spurring operating strategies aimed at environmental protection in industry, hence maintaining the momentum in climate change actions. However, it should be noted that the values of the carbon tax are obtained by simulating the process in an arbitrarily chosen month. For this reason, the carbon tax could be over-influenced by the simulated conditions of the grid. Running the production schedule over longer periods (e.g. one year) should be considered to obtain more reliable estimation of the carbon tax.

1

Industrial flexibility as demand-side response for electrical grid stability

2

Can grid-connected processes contribute to grid flexibility? What is the financial compensation to industrial actors for providing such a service?

Overview

- Rolling scheduling model that provides optimization of the short-term schedule.
- Application to an industrial batch process.
- Concept of "equivalent battery" that allows flexible operation by storing electricity as intermediate products.
- Methodology for pricing industrial flexibility as an ancillary service for the electrical grid.

This chapter is a preprint version of the article [50] submitted for publication.

Electricity markets are currently experiencing a period of rapid change. The intermittent nature of renewable energy is disrupting the conventional methods used in operational planning of the electrical grid, causing a shift from a day-ahead forecast policy to a real-time pricing of delivered electric power. A path towards a more renewable, robust and intelligent energy system is inevitable but poses many challenges to researchers and industry. In the field of process industry, strategies based on demand side response (DSR) are receiving attention and could represent a partial solution for this challenge. Coordination between production scheduling and procurement of electric power is of high importance and can contribute to reducing cost and emissions associated with production.

A methodology to quantify such benefits is presented here with a case study, which reveals the potential benefits of flexible operation. The method follows a rolling scheduling approach that provides optimization of the short-term schedule. This work introduces the concept of representing flexible processes as 'equivalent batteries' which store electricity from low-cost periods as intermediate products and consume the embedded energy during high-cost periods. Cost related to providing flexibility combined with the profits from optimized process scheduling contribute toward monetization of flexibility as an ancillary service for the grid. Balancing this service with the cost of implementing DSR solutions provides a means for calculating a pricing strategy for grid flexibility.

Introduction

2

Deep electrification paired with renewable-based generation has been identified by Europe as the main pathway for achieving a climate neutral economy by 2050. Future outlooks show that the share of electricity in final energy demand will at least double by the same year, reaching 53%, and electricity production will increase by up to 2.5 times current levels, depending on the options selected for the energy transition [51]. Reliable operation of the electricity grid is a fundamental requirement for this transition, but the conventional approach is constantly embattled by developments in variable generation, distribution outages and unexpected load changes [4]. Reliable power systems must guarantee a constant balance between supply and demand, which is achievable by efficient communication and flexible relations between suppliers and consumers [5]. In this regard, demand side response (DSR) can play a significant role in handling variability of electricity systems and therefore contribute towards balancing the grid. Moreover, the progressive electrification of numerous sectors could trigger competitive markets in ancillary services and encourage industry to provide responsive loads. Fair remuneration strategies should be identified to balance the incremental operating cost and open the door to flexible industrial consumers.

Recently, the allowance of unconventional grid resources such as demand response (DR) [6] contributed to grid balancing and improved the quality of the supplied electric power. Grid customers can benefit from lower wholesale market prices, increased reliability and system security [7], while guaranteeing favorable conditions to the grid operator. Peak load reduction translates into reducing requirements for expensive generation reserves and avoided capacity costs, such as the need for distribution and transmission infrastructure upgrades [8]. DR techniques based on real-time load shifting can additionally support variable generation [9], fostering the proliferation of distributed renewable energy resources as power generation devices connected to the grid.

Contribution

Industrial customers can play a major role in reducing demand on request [10] due to their high power consumption. This type of flexibility services are based on contracts between utility and customer, [11] which stipulate payments for load restrictions using peak load reduction programs. Attempts have been made by researchers to formulate methods for designing such contracts, starting from fundamental studies [12], to more elaborated solutions that exploit pool-based mechanisms for market clearing [13–15]. Although providing effective pricing techniques in flexible power systems, such methods do not use realistic models for quantifying consumer marginal costs due to power restrictions. This clear lack of complete methods for ensuring fair sharing of costs and benefits among stakeholders has motivated the research presented in this work. The proposed method allows quantification of the minimum financial compensation for industrial consumers to provide flexible load shifting services. Such results could either represent a starting value for the stipulation of fair contracts between stakeholders, or a minimum bid in a competitive and liberalized market of ancillary services.

2.1 Overview

This work investigates the effect of responsive loads on marginal cost due to power restrictions imposed on industrial consumers by the grid operator. The method follows a demand-side response strategy for optimal operations scheduling with corrective actions when unexpected events occur, i.e. power restrictions. A prediction-based optimizer with a 24-hour time horizon is applied to an industrial batch process and simulated over one month with hourly shifts of the rolling window. A scheduling model is embedded in the controller using a mixed-integer linear programming (MILP) formulation and solved at each iteration of the algorithm. Restrictions on the power consumption are simulated using the Monte Carlo method with pseudo-random drawings from a Sobol sequence, and implemented as operating constraints. The intensities of the power restrictions are calculated as percentage deviation from the optimal power profile, which is obtained by operating the process in unperturbed state. Moreover, the study introduces the concept of industrial processes as equivalent batteries that allow flexible operation by storing electricity as intermediate products during certain periods and consuming it in others. Finally, this work analysis the effect of power constraints on process performance and investigates the influence of their intensity and frequency on the marginal cost by simulating the process in different European countries.

2.2 Rolling scheduling model

Industrial use case

The process is divided into two sub-systems producing different types of final products, A and B. Each product is characterized by its sequence that uses only one raw material (raw A and raw B), as shown in Figure 2.2.1. Raw materials are converted to products through a number of independent jobs which comprise single or multiple operations, each of them requiring electricity. In total, there are 13 operations to be accounted for, belonging to 10 jobs. The intermediates produced by each job can either be stored or directly sent to the next job in the sequence. A total of five production lines can be used for scheduling the operations. The process runs at 70% of its full load capacity reflecting real operating conditions of the case study.

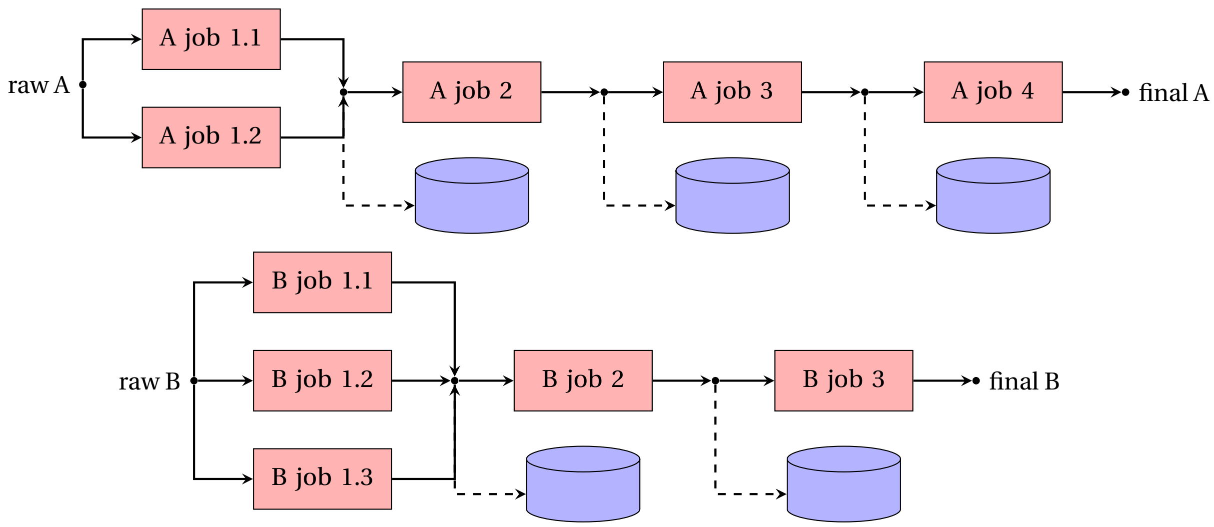

Figure 2.2.1 – Scheme of the use case batch process, comprising 10 jobs and 13 operations (not represented).

2

Problem formulation

The formulation of the scheduling problem is based on a discrete time representation. The time window is divided into intervals of equal duration (20 minutes). Each iteration of the algorithm therefore involves solving the scheduling problem over a single day rolling window for a total of 72 time slots. The duration of the time step was selected as the smallest common factor among all processing times required by the operations. Based on this representation of the time horizon, the following variables [1] are introduced:

- $x_{t,r,j,p}$ binary variable - 1 if operation p of job j is scheduled in resource r at time t, 0 otherwise.
- $I_{m,t}$ integer variable representing the level of inventory of material m at time t. m is defined within **M**, a set that contains all materials involved in the system (raw materials, intermediates and final products).

The two variables x and I are subject to constraints that represent process requirements and external impositions such as deliveries of raw materials and demand satisfaction. The constraints (2.1–2.12) can be identified:

1. Not allowed resources: Eq. 2.1 restricts the usage of resources for operation p, excluding those which cannot process job j.

$$\sum_{t\in\mathbf{T}}\sum_{r\in\mathbf{R}:\, r\notin\mathbf{AR}_j} x_{t,r,j,p} = 0 \quad \forall\ j\in\mathbf{J}, p\in\mathbf{O}_j \tag{2.1}$$

[1] *Variables* are expressed using italic font while roman font is used for parameters.

where $\mathbf{AR}_j$ is the set of the allowed resources and $\mathbf{O}_j$ is the sequence of ordered operations, also denoted as $\langle \mathrm{p}_1, ..., \mathrm{p}_\mathrm{u} \rangle_j$ with p_u being the last operation of j. $\mathbf{T}$ is also defined as an ordered sequence and it can be written as $\langle \mathrm{t}_1, ..., \mathrm{t}_\mathrm{n} \rangle$ with n equal to the number of time slots in the rolling window.

2. Allocation constraints: Ensures that at most one operation is scheduled in production line r at time t, as expressed in Eq. 2.2.

$$\sum_{j \in \mathbf{J}} \sum_{p \in \mathbf{O}_j} x_{t,r,j,p} \leq 1 \quad \forall\, t \in \mathbf{T}, r \in \mathbf{R} \tag{2.2}$$

Additionally, a second relation should ensure a proper duration of the scheduled operations. This is achieved by preventing an operation from starting before the end of the previous operation on the same production line (Eq. 2.3).

$$\sum_{g \in \mathbf{J}} \sum_{v \in \mathbf{O}_g} \sum_{h \in \mathbf{T}'} x_{h,r,g,v} - 1 \leq \mathrm{Z}(1 - x_{t,r,j,p}) \quad \forall\, t \in \mathbf{T}, j \in \mathbf{J}, p \in \mathbf{O}_j, r \in \mathbf{AR}_j \tag{2.3}$$

with $\mathbf{T}' = \langle \mathrm{t}, ..., \mathrm{t} + \mathrm{RT}_{\mathrm{j,p}} - 1 : h \leq \mathrm{t}_\mathrm{n} \rangle$ and Z a sufficiently large positive number calculated reflecting the problem size: $\mathrm{Z} = \sum_{j \in \mathbf{J}} \sum_{p \in \mathbf{O}_j} 1$.

3. Initialisation constraints: These constraints simplify the problem in the early time slots. Three main constraints can be defined. The first (Eq. 2.4) avoids scheduling an operation if insufficient time has passed to conclude all previous operations within the same job. This constraint accounts for the schedule of the previous iteration and avoids re-scheduling jobs that have already started.

$$x_{t,r,j,p} = 0 \quad \forall\, j \in \mathbf{J}, r \in \mathbf{AR}_j, p \in \langle \mathbf{O}_j : p \neq \mathrm{p}_1 \rangle, t \in \langle \mathrm{t}_1, ..., \sum_{v \in \langle \mathrm{p}_1, ..., \hat{\mathrm{p}} \rangle} \mathrm{RT}_{\mathrm{j,v}} : \sum_{g \in \mathbf{J}} \sum_{v \in \mathbf{O}_g} \mathrm{C}_{\mathrm{r,g,v}} = 0 \rangle \tag{2.4}$$

where $\mathrm{RT}_{\mathrm{j,v}}$ is the required processing time in number of time slots, $\hat{p}$ is the previous operation of p in the sequence $\mathbf{O}_j$ and $\mathrm{C}_{\mathrm{r,j,p}}$ is an auxiliary parameter used for transferring information from one iteration of the algorithm to the next one. $\mathrm{C}_{\mathrm{r,j,p}}$ indicates whether an operation is currently being processed: it is equal to 0 if the operation is not yet started, or it assumes an integer value equal to the number of time slots already spent processing p otherwise. This constraint is taken into account only if condition $\sum_{g \in \mathbf{J}} \sum_{v \in \mathbf{O}_g} \mathrm{C}_{\mathrm{r,g,v}} = 0$ is satisfied, meaning that Eq. 2.4 is added to the optimization problem only if no job is scheduled in the first time slot. Conversely, if an operation is not concluded at the end of an iteration, it is carried over to the next schedule as formulated by Eq. 2.5.

$$\sum_{g \in \mathbf{J}} \sum_{v \in \mathbf{O}_g} \sum_{t \in \mathbf{T}''} x_{t,r,g,v} = 0 \;\; \text{if } 1 \leq \mathrm{C}_{\mathrm{r,j,p}} \leq \mathrm{RT}_{\mathrm{j,p}} - 1 \quad \forall\, j \in \mathbf{J}, r \in \mathbf{AR}_j, p \in \mathbf{O}_j \tag{2.5}$$

where $\mathbf{T}'' = \langle \mathrm{t}_1, ..., \mathrm{RT}_{\mathrm{j,p}} - \mathrm{C}_{\mathrm{r,j,p}} \rangle$ are the first $\mathrm{RT}_{\mathrm{j,p}} - \mathrm{C}_{\mathrm{r,j,p}}$ time slots allocated to operation p of job j. Moreover, to ensure proper sequencing in the early time slots, a third constraint must be added, Eq.

2.6.

$$x_{\mathrm{RT}_{\mathrm{j},\hat{\mathrm{p}}}-\mathrm{C}_{\mathrm{r},\mathrm{j},\hat{\mathrm{p}}}+1,r,j,p} = 1 \quad \forall\ j \in \mathbf{J}, r \in \mathbf{AR}_j, p \in \langle \mathbf{O}_j : p \neq \mathrm{p}_1 \rangle \tag{2.6}$$

that is valid only if $\mathrm{C}_{\mathrm{r,j,\hat{p}}} \geq 1$ and $\mathrm{C}_{\mathrm{r,j,p}} = 0$, conditions meaning that the previous operation of p ($\hat{p}$) in the sequence was not concluded during the previous iteration.

4. Operations precedence: The constraint in Eq. 2.7 stipulates that an operation cannot start if the previous one within the same job has not been scheduled.

2

$$x_{t,r,j,p} \leq x_{t-\mathrm{RT}_{\mathrm{j},\hat{\mathrm{p}}},r,j,\hat{p}} \quad \forall\ j \in \mathbf{J}, p \in \langle \mathbf{O}_j : p \neq \mathrm{p}_1 \rangle, r \in \mathbf{AR}_j, t \in \langle \mathbf{T} : t - \mathrm{RT}_{\mathrm{j},\hat{\mathrm{p}}} \geq \mathrm{t}_1 \rangle \tag{2.7}$$

5. Operations sequence: Job operations must be performed sequentially and without stops since storage is not available between operations of the same job (Eq. 2.8). This constraint can be formulated similarly to Eq. 2.7 with the difference being that an operation is set to 1 if its previous one in the sequence ($\hat{p}$) is scheduled at time $t - \mathrm{RT}_{\mathrm{j},\hat{\mathrm{p}}}$.

$$x_{t,r,j,p} \geq x_{t-\mathrm{RT}_{\mathrm{j},\hat{\mathrm{p}}},r,j,\hat{p}} \quad \forall\ j \in \mathbf{J}, p \in \langle \mathbf{O}_j : p \neq \mathrm{p}_1 \rangle, r \in \mathbf{AR}_j, t \in \langle \mathbf{T} : t - \mathrm{RT}_{\mathrm{j},\hat{\mathrm{p}}} \geq \mathrm{t}_1 \rangle \tag{2.8}$$

6. Material sufficiency: Eq. 2.9 ensures that a job cannot start processing if the level of inventory of a material $I_{m,t}$ is insufficient. The constraint is formulated by introducing a new set $\mathbf{JR}_m$ denoting all the jobs requiring m and defined as a proper subset of $\mathbf{J}$ ($\mathbf{JR} \subset \mathbf{J}$).

$$\sum_{j \in \mathbf{JR}_m} \sum_{r \in \mathbf{AR}_j} x_{t,r,j,\mathrm{p}_1} \leq \begin{cases} \mathrm{I}_{\mathrm{m}}, & \text{if } t = 1 \\ I_{m,t-1}, & \text{if } t > 1 \end{cases} + \begin{cases} \mathrm{DS}_{\mathrm{t,m}}, & \text{if } t \in \mathbf{DD} \text{ and } m \in \mathbf{RM} \\ 0, & \text{otherwise} \end{cases} \quad \forall\ t \in \mathbf{T}, m \in \mathbf{RI} \tag{2.9}$$

$$\mathrm{I}^{\mathrm{i}}_{\mathrm{m}} = \begin{cases} 0, & \text{if i} = 1 \\ I^{\mathrm{i-1}}_{m,s}, & \text{if i} > 1 \end{cases} \quad \forall\ m \in \mathbf{RI} \tag{2.10}$$

where I_{m} is the level of inventory at the beginning of the schedule (Eq. 2.10). This parameter is initialized to the level of inventory at the step length s ($I_{m,s}$) of the previous iteration, where s is equal to the number of time slots shifted at each iteration of the rolling window. **RI** is the raw materials and intermediates set contained in **M** ($\mathbf{RI} \subset \mathbf{M}$). The other two sets introduced in Eq. 2.9, **DD** and **RM**, represent the delivery dates and raw material sets ($\mathbf{RM} \subset \mathbf{RI}$), respectively. Finally, $\mathrm{DS}_{\mathrm{t,m}}$ is the delivery size, in number of batches, of material m at the start of time slot t.

7. Inventory balance: This constraint ensures the mass balance in each inventory of material m. It is constructed as a sum of contributions as shown in Eq. 2.11.

$$I_{m,t} = \begin{cases} \mathrm{I_m}, & \text{if } t = 1 \\ I_{m,t-1}, & \text{otherwise} \end{cases} - \begin{cases} \sum_{j\in\mathbf{JR}_m}\sum_{r\in\mathbf{AR}_j} x_{t,r,j,\mathrm{p_1}}, & \text{if } m \in \mathbf{RI} \\ 0, & \text{otherwise} \end{cases}$$
$$+ \begin{cases} \sum_{j\in\mathbf{JP}}\sum_{r\in\mathbf{AR}_j} 1, & \text{if } m \in \mathbf{PI} \text{ and } \sum_{p\in\mathbf{O}_j}\mathrm{C_{r,j,p}} \neq 0 \text{ and } t = \mathrm{RT_j} - \sum_{p\in\mathbf{O}_j}\mathrm{C_{r,j,p}} \\ 0, & \text{otherwise} \end{cases}$$
$$+ \begin{cases} \sum_{j\in\mathbf{JP}}\sum_{r\in\mathbf{AR}_j} x_{t-\mathrm{RT_j}+1,r,j,\mathrm{p_1}}, & \text{if } m \in \mathbf{PI} \text{ and } t - \mathrm{RT}_{\mathbf{j}} \geq 0 \\ 0, & \text{otherwise} \end{cases}$$
$$+ \begin{cases} \sum_{d\in\mathbf{DD}}\mathrm{DS_{d,m}}, & \text{if } m \in \mathbf{RM} \text{ and } d = t \\ 0, & \text{otherwise} \end{cases}$$
$$- \begin{cases} \sum_{d\in\mathbf{DD}}\mathrm{DS_{d,m}}, & \text{if } m \in \mathbf{P} \text{ and } d = t \\ 0, & \text{otherwise} \end{cases} \quad \forall\ m \in \mathbf{M}, t \in \mathbf{T} \tag{2.11}$$

where $\mathrm{RT_j}$ is the total time required by job j ($\sum_{p\in\mathbf{O}_j}\mathrm{RT_{j,p}}$). Each inventory $I_{m,t}$ describes the quantity of material m stored at the end of each discrete time slot t. It is calculated as the sum of the previous inventory $I_{m,t-1}$ (1^{st} term) and additional terms representing the consumption of material (2^{nd} term) and the production of intermediates and final products (3^{rd} and 4^{th} terms), with $\mathbf{JR}_m$ and $\mathbf{JP}_m$ being the sets of jobs requiring and producing material m, respectively. The balance also accounts for the deliveries of raw materials (5^{th} term) and demand requirements (6^{th} term). Note that since $I_{m,t}$ is defined as an integer variable always greater than or equal to 0, the production demand of the process is satisfied for each delivery date d of size $\mathrm{DS_{d,m}}$.

8. Maximum storage capacity: Allows the storage capacity to be constrained for each intermediate m in the intermediates set $\mathbf{I}$ ($m \in \mathbf{I}$). This constraint (Eq. 2.12) can be written in the optimization problem as:

$$I_{m,t} \leq \mathrm{SC_m} \quad \forall\ m \in \mathbf{I}, t \in \mathbf{T} \tag{2.12}$$

where $\mathrm{SC_m}$ is a parameter representing the maximum storage capacity of m.

The auxiliary parameter $\mathrm{C_{r,j,p}}$ is used to link two consecutive iterations. The results of the schedule optimized at iteration i are passed to the next iteration i+1 by setting C of iteration i+1, for simplicity called $\mathrm{C^{i+1}}$, equal to an additional auxiliary variable (y) that is calculated once the optimal schedule of iteration i is found. y^{i} allows the identification of the operations that are not ended at iteration i and have to be considered in the next moving window, i+1. This variable has the same structure as C and its value depends on the step length s. Since this method considers day-ahead spot-electricity prices and a time-slot duration (w) of 20 minutes, the step length is set to three. The relations

(2.13–2.16) can be finally identified:

$$\mathrm{C}^{\mathrm{i}+1}_{\mathrm{r,j,p}} = y^{\mathrm{i}}_{r,j,p} \tag{2.13}$$

$$y^{\mathrm{i}}_{r,j,p} = \begin{cases} A, & \text{if } \mathrm{RT_j} - \sum_{v\in \mathbf{O}_j} \mathrm{C_{r,j,v}} \geq \mathrm{s}+1 \text{ and } \sum_{v\in \mathbf{O}_j} \mathrm{C_{r,j,v}} \neq 0 \\ 0, & \text{otherwise} \end{cases}$$
$$+ \begin{cases} B, & \text{if } \sum_{t\in \tilde{\mathbf{T}}} x_{t,r,j,\mathrm{p_1}} = 1 \text{ and } t + \mathrm{RT_j} - 1 > \mathrm{s} \\ 0, & \text{otherwise} \end{cases} \quad \forall\, r \in \mathbf{R}, j \in \mathbf{J}, p \in \mathbf{O}_j \tag{2.14}$$

with $\tilde{\mathbf{T}} = \langle \mathbf{T} : t \leq \mathrm{s} \rangle$ and the two terms A and B accounting for the jobs that require more time than the step length s. More precisely, while A (Eq. 2.15) represents the operations that started in the previous iteration, B (Eq. 2.16) refers to the jobs starting in the current window. Any job outside these two categories does not require tracking into the next iteration.

$$\begin{aligned} A = {} & \mathrm{C_{r,j,p}} \\ & + \begin{cases} \mathrm{s}, & \text{if } \mathrm{C_{r,j,p}} + \mathrm{s} < \mathrm{RT_{j,p}} \text{ and } \mathrm{C_{r,j,p}} \neq 0 \\ 0, & \text{otherwise} \end{cases} + \begin{cases} \mathrm{RT_{j,p}} - \mathrm{C_{r,j,p}}, & \text{if } \mathrm{RT_{j,p}} - \mathrm{C_{r,j,p}} \leq \mathrm{s} \text{ and } \mathrm{C_{r,j,p}} \neq 0 \\ 0, & \text{otherwise} \end{cases} \\ & + \begin{cases} \sum_{t\in \tilde{\mathbf{T}}} x_{t,r,j,p} \mathrm{RT_{j,p}}, & \text{if } t + \mathrm{RT_{j,p}} - 1 < \mathrm{s} \\ 0, & \text{otherwise} \end{cases} + \begin{cases} \sum_{t\in \tilde{\mathbf{T}}} x_{t,r,j,p} (\mathrm{s} - t + 1), & \text{if } t + \mathrm{RT_{j,p}} - 1 \geq \mathrm{s} \\ 0, & \text{otherwise} \end{cases} \end{aligned} \tag{2.15}$$

$$\begin{aligned} B = {} & \begin{cases} \sum_{t\in \tilde{\mathbf{T}}} x_{t,r,j,p} \mathrm{RT_{j,p}}, & \text{if } t + \mathrm{RT_{j,p}} - 1 < \mathrm{s} \text{ and } \sum_{v\in \langle \mathrm{p},\ldots,\mathrm{p_u} \rangle_j} \mathrm{RT_{j,v}} > \mathrm{s} - t + 1 \\ 0, & \text{otherwise} \end{cases} \\ & + \begin{cases} \sum_{t\in \tilde{T}} x_{t,r,j,p} (\mathrm{s} - t + 1), & \text{if } t + \mathrm{RT_{j,p}} - 1 \geq \mathrm{s} \\ 0, & \text{otherwise} \end{cases} \end{aligned} \tag{2.16}$$

Finally, the scheduling variable x allows the calculation of the total electricity power consumption at time t, denoted by P_t, through the relation expressed in Eq. 2.17.

$$P_t = \sum_{j\in\mathbf{J}} \sum_{p\in\mathbf{O}_j} \sum_{q\in\mathbf{T}'''} \sum_{r\in\mathbf{AR}_j} \mathrm{e_{j,p}}\, x_{q,r,j,p} + \begin{cases} \sum_{j\in\mathbf{J}} \sum_{p\in\mathbf{O}_j} \sum_{r\in\mathbf{AR}_j} \mathrm{e_{j,p}}, & \text{if } t \le \mathrm{RT_{j,p}} - \mathrm{C_{r,j,p}} \text{ and } \mathrm{C_{r,j,p}} \neq 0 \\ 0, & \text{otherwise} \end{cases} \quad \forall\, t \in \mathbf{T} \tag{2.17}$$

where $\mathbf{T}''' = \langle t - \mathrm{RT_{j,p}} + 1, \ldots, t : q \ge \mathrm{t_1} \rangle$ and $\mathrm{e_{j,p}}$ is the power required by p. The minimization of the operating cost can be finally expressed using the variable P_t as shown in Eq. 2.18:

$$\min_x \sum_{t\in\mathbf{T}} P_t \frac{\mathrm{w}}{60} \mathrm{c_t} \tag{2.18}$$

where $\mathrm{c_t}$ is the electricity price at time t.

2

2.3 Discrete rolling scheduling algorithm

The rolling scheduling model is solved on an hourly basis with continuity between iterations. The day-ahead electricity price forecasts are queried from the ENTSO-E API at the end of each hour (i) and converted into input data for the next iteration $(\mathrm{i}+1)$. The operation scheduling problem is then solved and the optimal decision variable x is found to schedule the operations on the available production lines for the next hour. The procedure (Fig. 2.3.1) is repeated until the iteration counter reaches its maximum allowed value N, namely the total number of simulated hours. At the end of each iteration, the scheduling variable x is used to derive variables I and y as shown in (2.11) and (2.14). These two variables are converted into parameters and injected again into the model by means of the relations expressed in (2.10) and (2.13).

The algorithm is run for the considered countries allowing the identification of the optimal power consumption profile. N is set to 720 for a single month simulation or to 4344 for a six-month simulation. The obtained profiles represent the best-case scenarios, in which operations can be scheduled under optimal operating conditions. Deviations from such profiles constitute sub-optimal solutions and are due to the introduction of external perturbations.

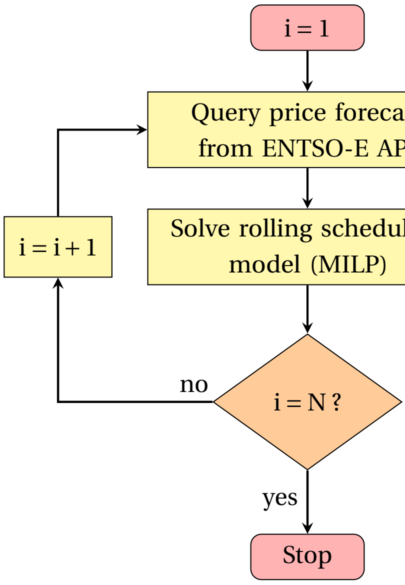

Figure 2.3.1 – Flow diagram of the on-line scheduling algorithm with rolling window approach.

Power limitations and modified rolling process

Power limitations imposed by the grid operator are simulated and their effect on the system performance is quantified in term of additional operating cost incurred by the process. Given the optimal power consumption profile $\mathrm{P}_\mathrm{t}^{\mathrm{opt}}$ over the considered time span of duration $\mathrm{s} \times \mathrm{N}$, the power constraint can be written as in Eq. 2.19.

$$P_t \leq \lambda_\mathrm{t} \mathrm{P}_t^{\mathrm{opt}} \quad \forall\, t \in \mathbf{TC} \tag{2.19}$$

where λ_t, within the interval $[0, 1]$, is the power factor representing the intensity of the restriction and **TC** is a proper subset of **T** (**TC** $\subset$ **T**) containing the time slots for which a power constraint is imposed. The newly defined constraint is added to the scheduling problem and the rolling process model modified as depicted in Fig. 2.3.2. The parameter $\mathrm{t}^{\mathrm{start}}$, within the interval $[1, \mathrm{s} \times \mathrm{N}]$, represents the initial time slot of the rolling window that is randomly selected for the power restriction. Together with **TC** and λ_t, $\mathrm{t}^{\mathrm{start}}$ constitutes a 3-dimensional space in which power curtailments can be applied to the process for different times and variable intensities.

A Sobol sequence is used for drawing samples and simulate the process with a Monte Carlo approach that ensures low discrepancy of the explored space. After each draw the variables are fed into the modified scheduling problem that is solved for a total of $\mathrm{N}^{\mathrm{min}}$ iterations. The latter parameter $\mathrm{N}^{\mathrm{min}}$, represents the minimum number of iterations required by the controller before converging to the unperturbed state P^{opt}.

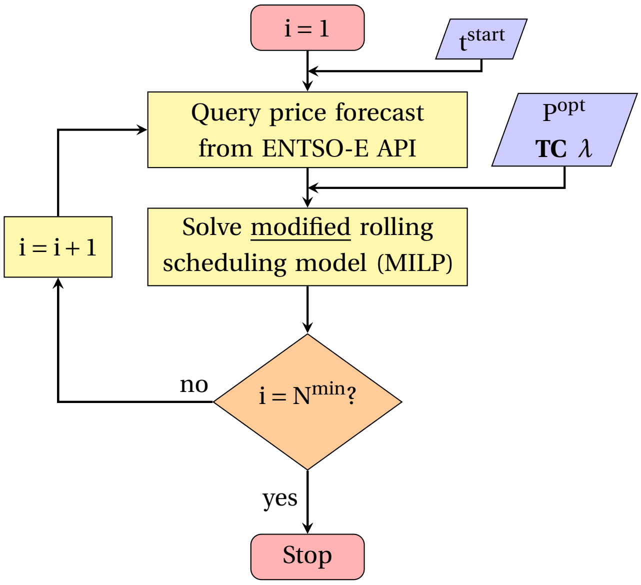

Figure 2.3.2 – Modified rolling process.

The execution of the modified algorithm enables analysis of system behaviour when unforeseen events occur, such as power restrictions, causing operations re-scheduling and therefore deviations from the optimal profile. Balancing between the increased operating cost due to the implementation of such a DSR-based control strategy and the grid service offered by the process encourages the definition of a methodology for pricing electrical flexibility related to the severity of the power restriction (EUR/MWh). Finally, the effect of restriction frequency on the incurred cost can be investigated by testing different sizes of the set **TC**.

2.4 Results and discussion

Fig. 2.4.1 shows the concept of the process as an equivalent battery plotted together with the electricity prices for Germany in the month of April 2018. The state of charge is defined as the cumulative electrical energy that is consumed to produce intermediates which are stored in buffers. The results show that the buffers are either charged or discharged during times of low electricity prices and kept constant in high-cost periods. Flat segments in the equivalent battery profile do not necessarily indicate a complete production stop but simply that the produced intermediates are directly sent to the next job in the sequence instead of being stored. In such time periods, the process runs at the lowest possible capacity to minimize the operating cost, while still meeting the delivery schedule.

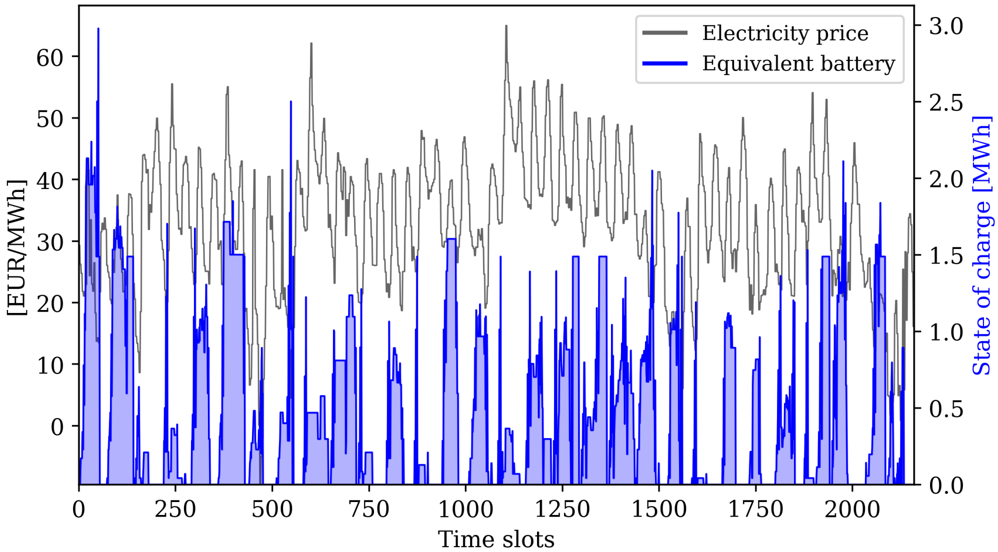

Figure 2.4.1 – Results of the rolling process. Equivalent battery plot (1 month simulation).

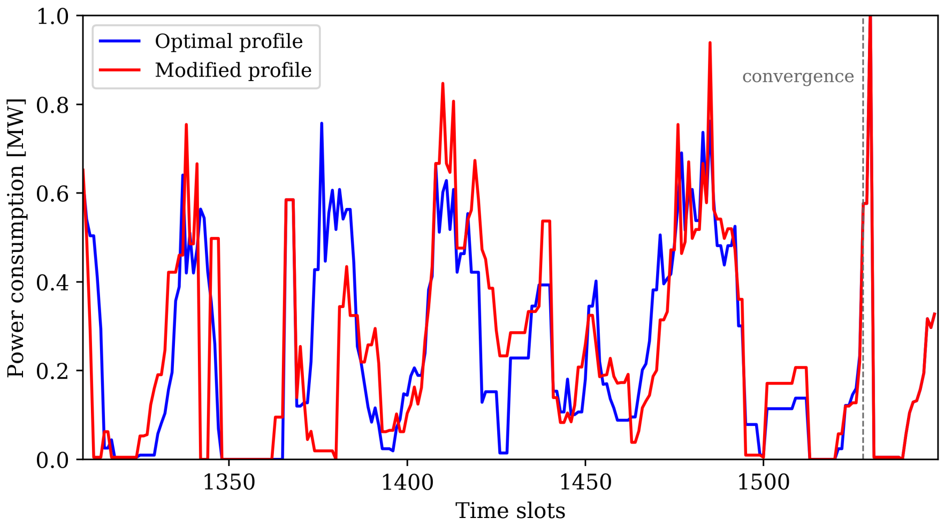

Figure 2.4.2 – Effect of restrictions on power profile.

Power restrictions from the grid operator would be expected either during periods of high price (reflecting high demand) or low renewable generation; however, a relationship between price and restriction could not be established from existing literature. Therefore, restrictions on power consumption are simulated by assuming random behaviour of the grid operator. The latter can require the process to completely or partially cut its power demand at any time of the schedule with notification ranging from one to twenty-four hours. Whenever the process is required to decrease its consumption, the schedule is completely updated and the process incurs some operating losses when compared to the optimal schedule. Fig 2.4.2 shows the deviation of the modified power profile (in red) from the optimal one (in blue) due to four restrictions with hourly duration for a total of 1.9 MWh. The convergence to the optimal consumption profile is reached after approximately 73 iterations of the modified rolling process (Fig. 2.3.2) as shown by the vertical dashed line in Fig. 2.4.2. All electricity demand restrictions simulated in this study are found to converge in less than 80 iterations; therefore, N^{min} was set to this value.

The same procedure is repeated several times using different frequencies and restriction intensities. The results of the simulations for Germany are illustrated in Fig. 2.4.3, which shows the incremental operating costs associated to electricity consumption in Euros per MWh of constrained electrical energy. Each point in the plot represents a simulation and different colors are used for each tested frequency f, measured in restrictions per day. Linear trends were identified in the results with increasing slope related to restriction frequency, meaning that the number of power constraints imposed on the process impacts marginal operating cost.

Moreover, it is observed that the obtained linear relations divide the graphs into two parts. The unfavourable zone is located in the lower side of the plot and represents situations that are likely unprofitable for the industrial customer. Any financial compensation placed in this zone and paid by the grid operator to the service provider would often be insufficient to compensate financial losses incurred by the consumer. Conversely, contracts for provision of a flexibility service that are placed above the marginal cost line can be defined as potentially favourable. Here, industry can either profit from providing grid services or potentially incur financial losses if load shifting techniques, such as the one presented in this work, are not adopted.

Moreover, Fig. 2.4.3 shows that the maximum admissible severity of a single restriction depends on f. This effect is represented by the different lengths of the marginal cost lines. Indeed, each single restriction cannot exceed a maximum threshold to avoid infeasible solutions of the schedule and to allow the process to meet its delivery requirements.

2

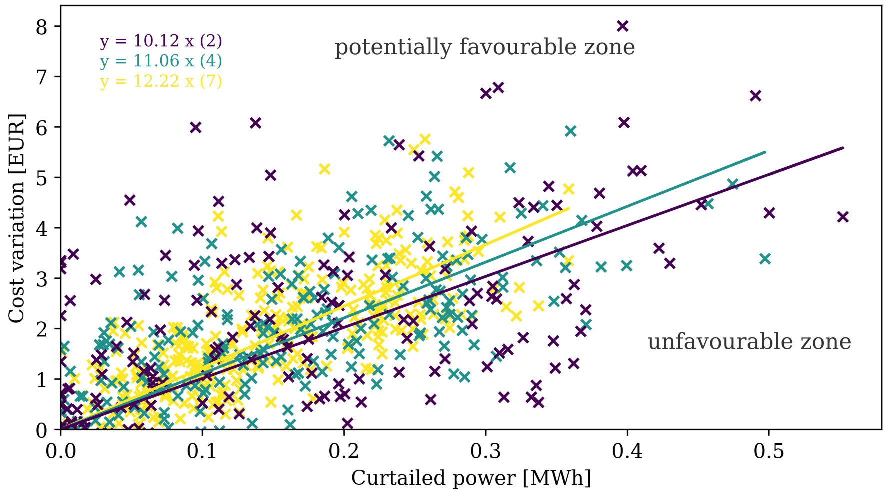

Figure 2.4.3 – Marginal operating costs due to power restrictions (Germany). April 2018. Correlations are denoted in the upper left corner. y and x represent cost variation and curtailed power, respectively. The slope is the required remuneration for the imposed curtailment (EUR/MWh) or the minimum bid in a liberalized market of ancillary services. The value in brackets () is the curtailment frequency, f.

By comparing Figs. 2.4.3 and 2.4.4, it is also noticeable that the correlations do not vary considerably for different durations of the time horizon. Similar slopes of the linear fits are obtained by constricting the power over a single month (April 2018) or a six-month period (January - June 2018). The relative differences between linear correlations of same frequency in the two periods reach a maximum value of 3.3% for $f = 7$. It can be concluded therefore, that results are relatively independent of the time horizon and are thus applicable throughout the year with little to be gained from examining extended periods of time.

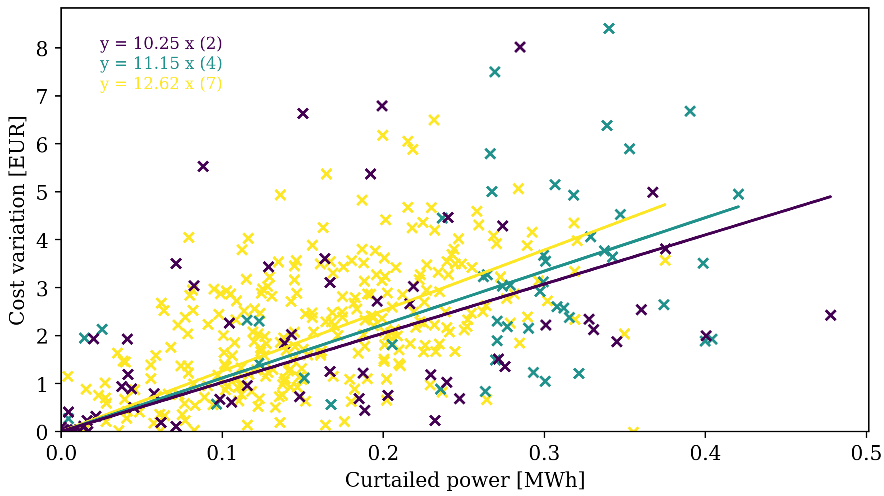

Figure 2.4.4 – Marginal operating costs. January - June 2018.

A similar effect to the influence of frequency f on the maximum admissible severity of a restriction is observed on the standard deviation of the simulated points (Tab. 2.4.1). The results reveal more scatter around the average values, identified by the marginal cost lines, at lower frequencies. Furthermore, the probability that a power restriction strategy would generate either very high or very low marginal cost is inversely proportional to the number of restrictions per day. This effect is demonstrated by the decreasing standard deviations of distributions associated to the tested frequencies. Tab. 2.4.1 gathers all the results obtained by testing the method in seven countries of the Euro zone for which a total of 4773 simulations are collected. A similar behavior to that obtained for Germany can be deduced.

	Marginal cost [$\frac{\mathrm{EUR}}{\mathrm{MWh}}$]			Standard deviation [$\frac{\mathrm{EUR}}{\mathrm{MWh}}$]		
Country	$f=2$	$f=4$	$f=7$	$f=2$	$f=4$	$f=7$
Germany	10.11 (182)*	11.06 (208)	12.22 (315)	1.64	1.09	0.79
France	10.32 (178)	11.08 (243)	12.24 (341)	1.57	1.16	0.95
Italy	12.63 (165)	14.09 (239)	16.63 (238)	2.29	1.53	1.49
Spain	7.59 (204)	8.63 (232)	10.56 (289)	1.30	1.16	1.09
Great Britain	10.75 (155)	12.99 (198)	14.55 (341)	2.25	1.60	1.13
Poland	9.83 (108)	10.25 (111)	10.80 (186)	1.54	1.08	0.95
Switzerland	9.92 (173)	10.75 (270)	11.83 (397)	1.89	1.08	1.02

* Number of simulations.

Table 2.4.1 – Results of the simulations for each country (April 2018).

2.5 Conclusion

In this work, a new methodology for pricing industrial flexibility as an ancillary service for electrical grids is proposed. Such a compensation is calculated in terms of service marginal cost per unit of restricted electrical energy and it represents the minimum indemnity that would encourage an industrial consumer to participate in grid balancing by load shifting. The service is achieved by implementing a demand side response strategy that minimizes the incremental cost through reactive response. Similar DSR solutions could be either used to shift energy consumption to off-peak hours or to aid grid operators in balancing intermittent generation from renewable sources.

Additionally, the study introduces the concept of industrial processes as flexible storage solutions for demand response with respect to the electrical grid. From the perspective of the electrical grid, the processes can be regarded as a battery with capacity related to their buffer capacity. Decoupled process operations, as in the case study used herein, can therefore mimic storage by temporally displacing operations with large energy requirements.

The findings show that the minimum compensation varies depending on the intensity and frequency of the power restrictions. Similar marginal cost relations are found for several European countries considered in this work. One limitation of the work is that the results might be dependent on the type of industrial process that was selected as a case study and on the level of production demand imposed by the schedule. Therefore, future work should focus on extending the investigation to consider the effect of schedule capacity on the marginal cost. Ultimately, this method provides a quantitative approach to estimate cost associated with industrial flexibility for providing grid services. Application of this method in industry would enable fair negotiation of flexibility contracts, and more broadly to estimate the total potential of grid flexibility services that could be provided by the European industrial sector, and the required compensation.

The indispensability of electricity storage for a 100% renewable Europe

What is the role of electricity storage in the future European grid? Which power sources are more promising when the electrification of the energy end-use is considered?

3

Overview

- New algorithm to efficiently generate macro designs of the future electricity grid.
- Electrification of the residential, service and mobility sectors in Europe.
- Multiple grid desings explored in a Monte Carlo approach with Sobol drawings.
- Definition of KPIs to assess the economic and environmental competitiveness.
- Self-sufficiency potential of renewable electricity and fundamental role of long- and short-term electricity storage to achieve a 100% renewable Europe.

This chapter is a preprint version of the article [52] submitted for publication.

This study considers the electrification of the future European households, services and mobility sectors through the large-scale deployment of heat pumping and electric vehicles. Heating and mobility demand profiles are constructed using hourly traffic data and external temperature measurements for more than 150 weather stations in Europe. Based on hourly capacity factors of hydro (run-of-river and water reservoir), solar (photovoltaic) and wind (onshore and offshore) generation, the importance of electricity storage is demonstrated on both long (day to season) and short (hours) time scales, that is achieved by P2G and batteries, respectively. The resolution of the hourly electricity balance with inter-storage transfer of energy allows to calculate the required capacities in terms of storage size, peak charging/discharging power and installed generation.

Different combinations of storage technologies and generation shares are explored using a Monte Carlo approach with pseudo-random drawing from a Sobol sequence. The collected solutions are validated using the renewable potential in each country, and compared in terms of LCOE [EUR/MWh] and climate change (Global Warming Potential – GWP100a). The model determines the equivalent carbon emissions per kWh of consumed electricity following a full life-cycle assessment approach with locally differentiated impact factors of the generation resources. The results show that PV panels are less attractive than wind and their use is limited to offsetting shortages in wind, whose production pattern is found to be complementary to solar in most countries. Moreover, the inclusion of long- and short-term storage of electricity in Europe reduces the need for overcapacity investments by a factor of two. As a consequence, decarbonization pathways based on storage with interconnected grids are associated with an environmental impact 33% lower compared to overbuilt solutions.

Introduction

There is a growing consensus that cross-sector flexibility is significant [31, 53] whereas different storage strategies are pivotal to closing the supply-and-demand gap. Robust and affordable future energy systems based on RE rely on the capacity to store substantial electricity on both short and long timescales. More importantly, as pointed out by Braff et al. [26] the ability to meet climate change goals with RE depends ultimately on self-sustaining adoption.

The largest share of RE is weather-dependent with hourly, daily and seasonal variations. Electricity self-sufficiency is achieved when the potential for RE exceeds the annual electricity demand. Trondle et al. [54] highlighted the complexity in assessing the potential of a single technology. Depending on the assumptions and limitations considered, European on-shore wind potential ranges from 4,400 TWh/y to 45,000 TWh/y; a similar uncertainty affects PV. Nevertheless, there seems to be a growing awareness that both technologies are in a position to satisfy the future European electricity demand. A fully renewable and self-sufficient Europe has proved achievable at country level [54], based on substantial investments on renewable technologies and the allocation of considerable fractions of non-built-up land. A recent review [22] emphasises the feasibility – both technical and economic – of a fully renewable European energy system, with a growing number of publications addressing the increasing electrification of society sectors.

Energy storage at different timescales is central in allowing a further growth of RE in energy systems [24, 54], smoothing seasonal fluctuations of intermittent generation, absorbing peaks of electricity production, offering network transmission services, while avoiding the need for generation oversizing. Storage also guarantees that RE can be fully dispatchable, a crucial feature for ubiquitous adoption. Acting in several time-scales, ranging from the hourly level, where batteries outperform, to weekly and monthly patterns, in which long-storage technologies are better suited [23, 32], is crucial for large-scale storage deployment. While no single technology outperforms all others [26] in both energy and power costs, storage technologies with longer storage duration have lower energy capacity costs and a modular behaviour between energy and power-related costs (i.e. adding to one component is independent of adding to the other) which constitutes an enhanced flexibility feature.

Contributions

This work proposes a complete framework to model large-scale grid systems considering electrification of the energy end-use in households, services and mobility sectors in Europe. All system constraints, such as availability of resources, currently installed capacities and locally-dependent capacity factors are considered to ensure feasible and realistic designs of the grid. Both isolated and interconnected designs of the energy systems are proposed and compared using economic and environmental metrics. Different types of batteries (lead-acid, lithium-ion, vanadium and zinc flow) and power-to-gas (SNG and Hydrogen) are included to highlight differences among competing technology options that are deemed promising for utility-size energy storage. Overall, the presented work takes into account a large number of variables (e.i. generation shares, storage technology choices, curtailments, interconnections) and metrics, such as frequently overlooked environmental indicators (GWP100a, GWP20a, RE share, ecological footprint, ecological scarcity), to develop a single consistent framework for the design and operation of the European power grids, which constitutes a novelty in literature.

3.1 Electricity generation and demand

A fully renewable electricity mix is considered, which is composed of hydro power technologies, such as run-of-river and water reservoir, offshore and onshore wind generation, and solar photovoltaics. Hourly generation profiles are constructed for each resource using 2019 as a reference year. The hourly data are fetched from the ENTSO-E public API [3] for each European country and validated, or if needed adjusted, using the annual cumulative generation provided by Eurostat [55] and the Swiss Federal Office of Energy (SFOE) [56–58] for the same year (Table C.1.1).

The currently installed capacities per production type are mostly obtained from the aggregated values of the ENTSO-E database [59]. Alternative data sources [58, 60–80] are used whenever the installed capacities are either inaccurate or not available from ENTSO-E. Moreover, generation shares [55] are used to exclude pumped hydro storage from the aggregated capacities, and in the case of Italy [81] and France [82] to estimate the total installed generation of run-of-river facilities. The current capacities of each hydro power resource in Switzerland are calculated using the data published by the SFOE [56] (Table C.1.2).

The generation profiles are further validated by comparing the calculated capacity factors to the average values observed in the reviewed literature [83, 84]. Whenever the annual average capacity factor of a technology falls outside the validity range, a correction factor is applied to the generation profile to ensure consistency with the literature (Table C.1.3).

Renewable energy potentials

Renewable energy potentials at national level were retrieved from the open ENSPRESO database [85] for solar (rooftops and facades with 100% artificial and 3% non-artificial land) and wind resources. For hydro, Bodis at al. [86] together with studies carried out by the European Commission [87, 88] were used. The former takes into account GIS-based land-restriction, geo-spatial wind speed and irradiation data, and the maximum electricity production from renewable sources was derived considering EU-wide low restrictions, such as low setback distance for wind turbines (Table C.1.4).

Although the potential of photovoltaic and offshore wind are non-zero in some countries, their penetration in the current mix may be zero due to lack of adoption. Hourly generation data are not available in such cases, therefore average solar and wind offshore profiles are used to account for future installations of these two technologies. Such profiles are constructed aggregating all normalised generations of the European countries where solar and offshore wind are currently installed.

Residential and services sectors

The hourly electricity demand profile is constructed assuming full electrification of the residential, service and mobility sectors (Table C.1.5). The current hourly electricity consumption is retrieved from the ENTSO-E database and heating demand is satisfied by mechanical heat pumping. Space heating and domestic hot water preparation are included in the heating demand using the final energy consumption data of the residential and service sectors from Eurostat [89, 90]. The heating degree index [91] is used to describe the need for space heating depending on the severity of the cold on an hourly basis, which is calculated assuming a base temperature of 15°C and a cut-off temperature of 18°C as described by domain-specfic standards [91]. Hourly values of the external air temperature are fetched from a weather API [42] for more than 150 weather stations located in the most populated areas of Europe (Tables C.1.6). A single average temperature profile is built for each country weighting the profiles by the population [92] of the corresponding cities. The hourly thermal profile for space heating is estimated using the heat transfer equations of domestic hydronic systems [93], assuming supply and return temperatures of 55°C and 45°C, respectively. Finally, the air temperature-variant coefficient of performance is calculated and used to estimate the total electricity demand associated with heat pumping. The same procedure is followed to calculate the energy requirement for domestic hot water, with a requirement of 65°C that ensures appropriate sanitary conditions.

Mobility

The total energy demand of mobility is retrieved from EU statistics [94], considering road and freight transport, and excluding aviation, which is negligible energy-wise. The hourly demand profiles are obtained assuming full electrification of private and public transportation (electric cars, buses and trains). They may not necessarily represent the power demand profiles of battery electric vehicles, as charging and discharging profiles differ from each other. However, as the profiles are significantly affected by the driver's behaviour and type of (re)charging station, traffic measurement data [95, 96] were used for simplification.

Cost data of generation technologies

The capital and the maintenance costs of the generation technologies are obtained from literature. Different research studies and technical reports are reviewed to construct cost distributions, with precedence given to more recent work. Costs associated with commissioning new PV facilities are mostly taken from the Lazard's levelized cost of energy analysis [97], the technical report provided by the IRENA [98] and the most recent EIA's energy outlook [99]. The same reports are used to obtain the cost of wind-based technologies, with the addition of the NREL study on the future of renewable energies [100] and other sources [73, 101–104].

Unlike solar and wind, the cost of hydro power is affected by high variability. Adding capacity to existing dams is significantly less expensive than commissioning new projects in remote sites with poor infrastructure. Although advancements in civil engineering will most likely drive expenses lower, the cost reduction of hydro generation has been far less significant than solar and wind technologies in the last decade. As reported by IRENA [98], hydro projects have occasionally witnessed more expensive developments compared to earlier projects due to more challenging site conditions. For this reason, the costs of run-of-river and hydro reservoirs are derived from recent work [105] as well as earlier studies [84, 106–109] to increase the number of data points in the distributions.

Moreover, medium- to long-term cost projections are included to account for future low-cost energy scenarios through uncertainty analysis. The baseline results are built for each country and the interconnected system by assuming deterministic cost parameters. Such deterministic values are assumed equal to the medians of the empirical distributions, rather than the means, to limit the impact of outliers and distribution tails on the reference conditions.

3.2 Storage models

Storage models are categorised based on their time-scale operation: short-term refers herein to batteries, whilst long-term storage refers to power-to-X technologies. Batteries are generally used over short time horizons because of their high self-discharge losses compared to other storage types, such as mechanical (e.g. PHS) or chemical (P2G) storage, and their possibly lower discharge time. Solving the design and operating management of batteries over one year can become computationally expensive; the charging/discharging strategy of batteries is therefore based on the sizing and operation strategy of the P2G plant. Four battery types are considered in this work, namely: lead-acid, lithium-ion, vanadium and zinc flow batteries. The two former types are widely used for electricity storage in the power and transportation sectors, whereas the two latter are deemed promising since they are easier to scale for utility-size energy storage and are characterised by a low-power density. The cost of each battery type is taken from the Lazard's report on the levelized cost of storage [110] and the NREL [111, 112].

Batteries' lifetime is calculated following the capacity degradation model proposed by Ranaweera et al. [113]. The model uses the average depth of discharge and the number of cycles to failure, namely the number of equivalent full discharges available from experimental results [114, 115], to estimate the total throughput of the battery during its lifetime. A conservative replacement criterion of 80% remaining capacity [116] is assumed to ensure good battery health during the entire operating period. Finally, the calculated throughput and the annual battery usage resulting from the simulations allow us to estimate the expected lifetime in years.

Regarding long-term storage, the focus is on P2G with hydrogen (H_2) or synthetic natural gas (SNG). Besides being a necessary step in all power-to-X schemes, H_2 generation has been gaining interest as a possible vector for energy storage. SNG production, although requiring an additional reaction step and thus implying lower efficiency, benefits from a widely developed infrastructure (storage, transport and power generation). Power-to-liquid options are discarded, as the production of liquid fuels such as methanol or ammonia is seen as a suitable option only in specific sectors, and large-scale liquid-to-power facilities are uncommon. The charging/discharging strategy of P2G plants was set considering a cyclic behaviour over one-year horizon. The cost associated with the installation of power-to-hydrogen facilities is obtained from well-known literature[117, 118], while the works of Denft et al. [119] and Gorre et al. [120] are used for modeling SNG processes.

3.3 Simulation algorithm

The modelling is conducted for an entire year with hourly resolution. The electricity supply and demand are matched on an hourly basis, charging or discharging storage units to remove excess electricity from the grid or inject it when demand exceeds generation. Moreover, the model follows an overnight approach that assumes electricity is entirely generated from renewable resources in all countries - therefore disregarding the transition from the current state. Strategic pathways to achieve such an energy system are not the focus of this work. The goal is rather to demonstrate how storage and large-scale networks would make the European economy more sustainable.

Multiple scenarios are generated by means of a simulation algorithm that uses a predefined set of parameters as input. Such parameters allow the selection of the long- and short-term storage types and the choice of the generation multipliers (m_g in equation 3.1), which represent the initial level of penetration of each generation technology in the production mix. Each generated scenario corresponds to a possible future evolution of events that would lead to a certain design of the energy system. The approach is deterministic, meaning that each scenario can be reproduced for a given set of input parameters.

Electricity generation profiles

The simulation algorithm iteratively scales the generation profiles of the electricity production technologies by means of the scaling factor s^{i}. Equation 3.1 shows how the generation mix, represented by the set **GT**, is updated at each iteration i. The electricity output $G_g^{\mathrm{i}}(h)$ from technology g ($g \in \mathbf{GT}$) at time h is obtained by multiplying the current generation $G_g^0(h)$ by the scaling factor and the multiplier m_g. Not all technologies are scaled, but only those for which enough potential is available. This constraint is formulated through the definition of the variable generation technology (**VGT**) set. **VGT** can either be a proper (**VGT** $\subset$ **GT**) or improper (**VGT** $\subseteq$ **GT**) subset of **GT**. The membership of a given technology g in set **VGT** can be written as in Equation 3.2, meaning that g is part of **VGT** only if its potential capacity PC_g is considerably greater than its current capacity CC_g. The use of **VGT** is fundamental to avoid unfeasible solutions in which the output from a certain resource exceeds the technical potential.

$$G_g^{\mathrm{i}}(h) = \begin{cases} G_g^0(h) \times s^{\mathrm{i}} \times m_g, & \text{if } g \in \mathbf{VGT} \\ G_g^0(h) \times m_g, & \text{otherwise} \end{cases} \tag{3.1}$$

$$\mathbf{VGT} = \{g \mid PC_g \gg CC_g,\ \forall g \in \mathbf{GT}\} \tag{3.2}$$

At each iteration i+1, the scaling factor s is either reduced or increased by the residual of the previous iteration r^{i} (Equation 3.3). This dimensionless residual represents the deficit ($r^{\mathrm{i}} > 0$) or excess ($r^{\mathrm{i}} < 0$)

annual electrical energy that is estimated for a certain design.

$$s^{\mathrm{i}+1} = s^{\mathrm{i}} + r^{\mathrm{i}} \quad \text{with} \quad s^1 = 1 \tag{3.3}$$

Electricity balance and convergence criterion

The residual r^{i} is calculated by summing the hourly contributions $r^{\mathrm{i}}(h)$ (Equation 3.4), which are obtained from the electricity balance expressed in Equation 3.5. The electricity balance is solved on an hourly basis and accounts for the electricity loss due to storage. The terms $S^{\mathrm{i}}_{long}(h)$ and $S^{\mathrm{i}}_{short}(h)$ represent the charged ($S^{\mathrm{i}}(h) > 0$) or net discharged ($S^{\mathrm{i}}(h) < 0$) electrical energy associated with long- and short-term storage, respectively, and the term $C^{\mathrm{i}}(h)$ is the electricity consumption.

$$r^{\mathrm{i}} = \sum_h r^{\mathrm{i}}(h) \tag{3.4}$$

3

$$\sum_g^{\mathbf{GT}} G^{\mathrm{i}}_g(h) = C^{\mathrm{i}}(h) + S^{\mathrm{i}}_{long}(h) + S^{\mathrm{i}}_{short}(h) + r^{\mathrm{i}}(h) \tag{3.5}$$

Convergence is achieved at the closure of the electricity balance. The stopping criterion adopted in the simulations ensures a good accuracy of the result. When the total residual r^{i} reaches 10^{-5}% of the annual demand the algorithm halts its execution and the last available iteration is considered as converged.

Operating profile and size of the long-term storage

At each iteration, the sizes of the long- and short-term storage are calculated according to the available power at different time scales. The two systems are designed sequentially, starting with the long-term one. The seasonal and daily excess of electricity is stored using the power-to-gas system and released in periods of high consumption. Conversely, the battery system is designed using the hourly power imbalances, hence ensuring grid stability over the short term. The algorithm starts with the calculation of the hourly power imbalances $p^{\mathrm{i}}_{hourly}(h)$, as defined in Equation 3.6.

$$p^{\mathrm{i}}_{hourly}(h) = \sum_g^{\mathbf{GT}} G^{\mathrm{i}}_g(h) - C^{\mathrm{i}}(h) \tag{3.6}$$

The daily electricity excess or deficit $p^{\mathrm{i}}_{daily}(d)$, namely the daily difference between the produced and consumed electric energy, is calculated at each iteration i by averaging the corresponding hourly values $p^{\mathrm{i}}_{hourly}(h)$ (Equation 3.7). This daily profile is subsequently used to calculate the power profile of the long-term storage $p^{\mathrm{i}}_{long}(d)$ as shown in Equation 3.10.

$$p^{\mathrm{i}}_{daily}(d) = \frac{1}{24} \sum_{h=24d}^{24d+23} p^{\mathrm{i}}_{hourly}(h) \tag{3.7}$$

where $p^{\mathrm{i}}_{hourly}(h)$ and $p^{\mathrm{i}}_{daily}(d)$ are two discrete functions in the positive integer domains $[0, 8759]$ and $[0, 364] \subset \mathbb{N}_0$, respectively.

$$E^{\mathrm{i}}_{\mathrm{d}} = \sum_{d} p^{\mathrm{i}}_{daily}(d) \;\text{ if }\; p^{\mathrm{i}}_{daily}(d) > 0 \tag{3.8}$$

$$D^{\mathrm{i}}_{\mathrm{d}} = \sum_{d} -p^{\mathrm{i}}_{daily}(d) \;\text{ if }\; p^{\mathrm{i}}_{daily}(d) < 0 \tag{3.9}$$

$$p^{\mathrm{i}}_{long}(d) = \begin{cases} p^{\mathrm{i}}_{daily}(d)\,\frac{E^{\mathrm{i}}_{\mathrm{d}}\,\eta^{\mathrm{rt}}_{\mathrm{l}}}{D^{\mathrm{i}}_{\mathrm{d}}}, & \text{if } D^{\mathrm{i}}_{\mathrm{d}} > E^{\mathrm{i}}_{\mathrm{d}}\,\eta^{\mathrm{rt}}_{\mathrm{l}} \text{ and } p^{\mathrm{i}}_{daily}(d) < 0 \\ p^{\mathrm{i}}_{daily}(d)\,\frac{D^{\mathrm{i}}_{\mathrm{d}}}{E^{\mathrm{i}}_{\mathrm{d}}\,\eta^{\mathrm{rt}}_{\mathrm{l}}}, & \text{if } D^{\mathrm{i}}_{\mathrm{d}} \le E^{\mathrm{i}}_{\mathrm{d}}\,\eta^{\mathrm{rt}}_{\mathrm{l}} \text{ and } p^{\mathrm{i}}_{daily}(d) > 0 \\ p^{\mathrm{i}}_{daily}(d), & \text{otherwise} \end{cases} \tag{3.10}$$

where $\eta^{\mathrm{rt}}_{\mathrm{l}}$ is the round-trip efficiency of the long-term storage, and $E^{\mathrm{i}}_{\mathrm{d}}$ (Eq. 3.8) and $D^{\mathrm{i}}_{\mathrm{d}}$ (Eq. 3.9) are the total annual excess and deficit energy at daily time scale at iteration i. The profile $p^{\mathrm{i}}_{long}(d)$ represents the power load associated to the long-term storage perceived by the electricity grid. This operating profile is constructed at each iteration using the set of Eqs. 3.10, which fits the storage power load to $p^{\mathrm{i}}_{daily}(d)$. Moreover, the inclusion of the round-trip efficiency in the set of equations ensures that the energy loss is considered during the charging and discharging phases. $p^{\mathrm{i}}_{long}(d)$ is afterwards used to calculate the hourly electrical intake or output of the storage as described by Eq. 3.11.

$$S^{\mathrm{i}}_{long}(h) = p^{\mathrm{i}}_{long}(d) \times 1\ [\text{hour}] \tag{3.11}$$

Operating profile and size of the short-term storage

After sizing the long-term storage, the hourly available power $p^{\mathrm{i}}_{avail}(h)$ is calculated as the difference between the hourly and the daily average excess or deficit power (Equation 3.12). The obtained profile corresponds to the operating load that the battery system could ideally follow to either store or discharge electricity. For this reason, $p^{\mathrm{i}}_{avail}(h)$ can be considered as the battery-equivalent of $p^{\mathrm{i}}_{daily}(d)$, and it can therefore be used to identify the true power profile of the short-term storage (Equation 3.15).

$$p^{\mathrm{i}}_{avail}(h) = p^{\mathrm{i}}_{hourly}(h) - p^{\mathrm{i}}_{daily}(d)|_{d=h\div 24} \tag{3.12}$$

$$E^{\mathrm{i}}_{\mathrm{h}} = \sum_{h} p^{\mathrm{i}}_{avail}(h) \text{ if } p^{\mathrm{i}}_{avail}(h) > 0 \tag{3.13}$$

$$D^{\mathrm{i}}_{\mathrm{h}} = \sum_{h} -p^{\mathrm{i}}_{avail}(h) \text{ if } p^{\mathrm{i}}_{avail}(h) < 0 \tag{3.14}$$

$$p^{\mathrm{i}}_{short}(h) = \begin{cases} p^{\mathrm{i}}_{avail}(h)\,\frac{E^{\mathrm{i}}_{\mathrm{h}}\,\eta^{\mathrm{rt}}_{\mathrm{s}}}{D^{\mathrm{i}}_{\mathrm{h}}}, & \text{if } D^{\mathrm{i}}_{\mathrm{h}} > E^{i}_{\mathrm{h}}\,\eta^{\mathrm{rt}}_{\mathrm{s}} \text{ and } p^{\mathrm{i}}_{avail}(h) < 0 \\ p^{\mathrm{i}}_{avail}(h)\,\frac{D^{\mathrm{i}}_{\mathrm{h}}}{E^{\mathrm{i}}_{\mathrm{h}}\,\eta^{\mathrm{rt}}_{\mathrm{s}}}, & \text{if } D^{\mathrm{i}}_{\mathrm{h}} \le E^{\mathrm{i}}_{\mathrm{h}}\,\eta^{\mathrm{rt}}_{\mathrm{s}} \text{ and } p^{\mathrm{i}}_{avail}(h) > 0 \\ p^{\mathrm{i}}_{avail}(h)), & \text{otherwise} \end{cases} \tag{3.15}$$

where $p^{\mathrm{i}}_{short}(h)$ is the battery-equivalent of $p^{\mathrm{i}}_{long}(d)$, $\eta^{\mathrm{rt}}_{\mathrm{s}}$ is the round-trip efficiency of the short-term storage, and $E^{\mathrm{i}}_{\mathrm{h}}$ (Eq. 3.13) and $D^{\mathrm{i}}_{\mathrm{h}}$ (Eq. 3.14) are the total annual excess and deficit energy at hourly time scale, respectively. As in the case of the long-term storage, the battery power profile $p^{\mathrm{i}}_{short}(h)$ can be used to calculate the hourly charged or discharged electricity as indicated by Eq. 3.16.

$$S^{\mathrm{i}}_{short}(h) = p^{\mathrm{i}}_{short}(h) \times 1 \text{ [hour]} \tag{3.16}$$

It should be noted that Eq. 3.12 enables the exchange of electricity between the two storage systems. The batteries indeed discharge energy whenever the generated electricity is insufficient for the demand and long-term charging load at the same time. Conversely, they can absorb the excess energy that is discharged by the long-term storage during hours of low demand. As a result, any sudden power imbalance is buffered by the batteries, ensuring smooth operating conditions of the power-to-gas system.

Accuracy error of the algorithm

Due to the storage inefficiency a residual power profile $p^{\mathrm{i}}_{res}(h)$ can be calculated from the difference between the storage load and the hourly excess and deficit profile (Eq. 3.17). A negative value of $p^{\mathrm{i}}_{res}(h)$ means that the excess power is greater than the combined storage and demand loads, hence the electricity generation is likely oversized. In such a case, the link imposed by Eqs. 3.18, 3.4 and 3.3 triggers a decrease of generation in the next iteration. Conversely, a positive value of $p^{\mathrm{i}}_{res}(d)$ indicates a deficit of electricity, leading to an increase of the generation scaling factor s at iteration $\mathrm{i}+1$.

$$p^{\mathrm{i}}_{res}(h) = p^{\mathrm{i}}_{short}(h) - p^{\mathrm{i}}_{hourly}(h) + p^{\mathrm{i}}_{long}(d)|_{d=h\div 24} \tag{3.17}$$

$$r^{\mathrm{i}}(h) = p^{\mathrm{i}}_{res}(h) \tag{3.18}$$

3

While the algorithm closes the annual electricity balance with high precision, the hourly residual energy term $p^{\mathrm{i}}_{res}(h)$ is typically non-zero. Although small, such error is inevitable due to a problem formulation that accounts for storage inefficiencies and constrains the shape of the electricity generation profile. The scaling factor s uniformly applies to each resource technology, limiting the freedom of the simulation algorithm in exploring alternative configurations which could lead to lower residuals. However, if instead technology-specific scaling factors were used, the problem would be shifted toward optimisation, leading to undesired complexity while still not ensuring full convergence of the hourly electricity balance.

The distributions of the hourly residuals (errors) generated by the implemented algorithm are shown in Fig. 3.3.1. The hourly error (median) varies between a minimum of 0.4% (Sweden) and a maximum of 4.8% (Belgium) of the demand, with the all-country weighted median equal to 1.3%. As expected, the errors are directly correlated with the variability of the electricity output, meaning that achieving convergence becomes more difficult with fluctuating generation. Overall, a similar average error can be considered sufficiently small, and certainly less significant than the uncertainty introduced by the demand projections and ENTSO-E generation data. Specifically, the latter is characterised by an average energy imbalance relative to demand of 3.9% (Tab. C.2.2). This error in background data alters the real shape of the generation capacity factors, affecting the solutions more than the inaccuracy caused by the simulation algorithm.

3

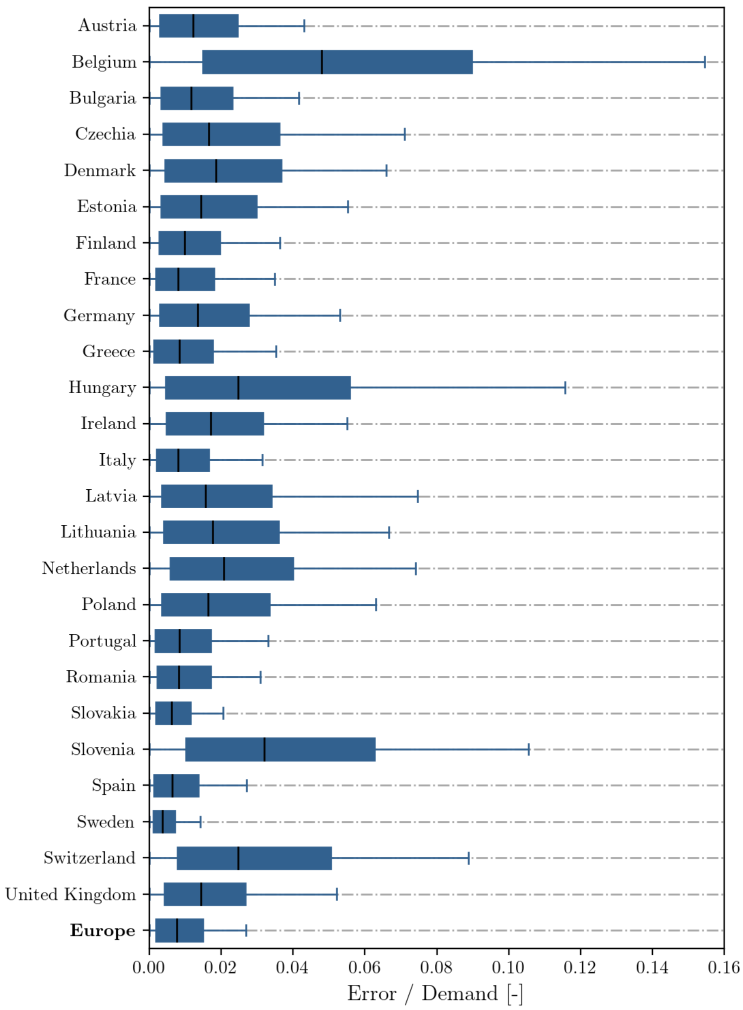

Figure 3.3.1 – Error distributions of the simulation algorithm by country. Residual of the hourly electricity balance calculated as relative error [-] with respect to the hourly electricity demand. Results in Table C.2.1.

Comparison with alternative approaches

Zero residuals could be achieved by allowing for energy accumulation or variable electricity curtailments. Energy accumulation in storage, cyclically asymmetric State of Charge (SOC), could be modelled by changing the set of Eqs. 3.10 and 3.15 with a formulation that ensures full cover of the energy deficit with discharges from storage. As a consequence, the power residual term $p^{\mathrm{i}}_{res}(h)$ would more likely assume positive values, pushing the convergence towards solutions with higher storage and generation capacity. Alternatively, variable curtailments could be implemented to avoid accumulation by increasing the share of direct electricity supply while losing potentially useful energy.

Despite closing the hourly balance with absolute precision, the two approaches lead to overbuilt generation and storage. This issue is prevented in this model. The proposed algorithm finds the storage operating profile by fitting its shape to the hourly excess and deficit power. The fitting is achieved by minimising the total annual error while taking into account the signs of the hourly energy residuals. As a result, the algorithm is not biased towards the under-sizing or over-sizing of the generation and storage capacities, a conclusion that is further supported by errors that are symmetrically distributed around zero (Fig. C.2.1).

State of charge and required capacity of storage

Once the algorithm achieves convergence, the SOC of the storage system can be calculated using the integral of the converged power functions $p_{short}(h)$ and $p_{long}(d)$. This integral is formulated using a cumulative summation function of the power profile (first term) in the discrete h and d domains. The sum is then shifted by the minimum storage level (second term) encountered over the simulated period, ensuring that the SOC function is always positive (Eqs. 3.19 and 3.20).

3

$$SOC_{short}(\tilde{h}) = \sum_{h=0}^{\tilde{h}} p_{short}(h) + \left|\min\left(\sum_{h=0}^{8759} p_{short}(h)\right)\right| \tag{3.19}$$

$$SOC_{long}(\tilde{h}) = \sum_{h=0}^{\tilde{h}} p_{long}(d)|_{d=h\div 24} + \left|\min\left(\sum_{h=0}^{8759} p_{long}(d)|_{d=h\div 24}\right)\right| \tag{3.20}$$

Finally, the storage capacity (SC) is calculated as the maximum value of the SOC (Eq. 3.21) and the total stored electricity (SE) by summing the positive values of the storage power profile (Eqs. 3.22 and 3.23).

$$SC_{short} = \max\left(SOC_{short}(\tilde{h})\right) \quad SC_{long} = \max\left(SOC_{long}(\tilde{h})\right) \tag{3.21}$$

$$SE_{short} = \sum_{h} \begin{cases} p_{short}(h), & \text{if } p_{short}(h) > 0 \\ 0, & \text{otherwise} \end{cases} \tag{3.22}$$

$$SE_{long} = \sum_{h} \begin{cases} p_{long}(d)|_{d=h\div 24}, & \text{if } p_{long}(d)|_{d=h\div 24} > 0 \\ 0, & \text{otherwise} \end{cases} \tag{3.23}$$

Summary of the algorithm procedure

The equations presented above are solved in the order specified in Algo. 1. The algorithm takes the current generation and demand profiles, the resource multipliers and the tolerance as inputs to iteratively design the energy system.

Algorithm 1 Simulation algorithm.

procedure BUILD SCENARIO($G_g^0(h), C(h), m_g, tol$) ▷ specify tolerance (e.g. 1e−5%)
  $i, r \leftarrow 0, 1$ ▷ initialise iteration counter and residual
  while true **do**
    $i \leftarrow i+1$
    if $i > 1$ **then**
      $s \leftarrow s+r$ ▷ update scale factor
    end if
    $G_g(h) \leftarrow$ `solve equation 3.1` ▷ solve equations in the following order
    $p_{hourly}(h) \leftarrow$ `solve equation 3.6`
    $p_{daily}(d) \leftarrow$ `solve equation 3.7`
    $p_{long}(d) \leftarrow$ `solve system 3.10 with 3.8 and 3.9`
    $p_{avail}(h) \leftarrow$ `solve equation 3.12`
    $p_{short}(d) \leftarrow$ `solve system 3.15 with 3.13 and 3.14`
    $p_{res}(h) \leftarrow$ `solve equation 3.17`
    $r \leftarrow$ `solve equations 3.18 and 3.4` ▷ update residual
  end while
  save simulation
end procedure

3.4 Sobol simulations

A Sobol sequence is used for drawing pseudo-random samples and simulate the process with a Monte Carlo approach that ensures low discrepancy of the explored space. Different combinations of technologies for the long- (Hydrogen and SNG) and short-term (Lead-acid, Lithium-ion, Vanadium and Zinc flow) storage, generation shares and curtailment factors are investigated (Fig. 3.4.1). After the drawing of each Sobol set of variables, the simulation algorithm is run until it reaches convergence, which is defined as the closure of the electricity balance.

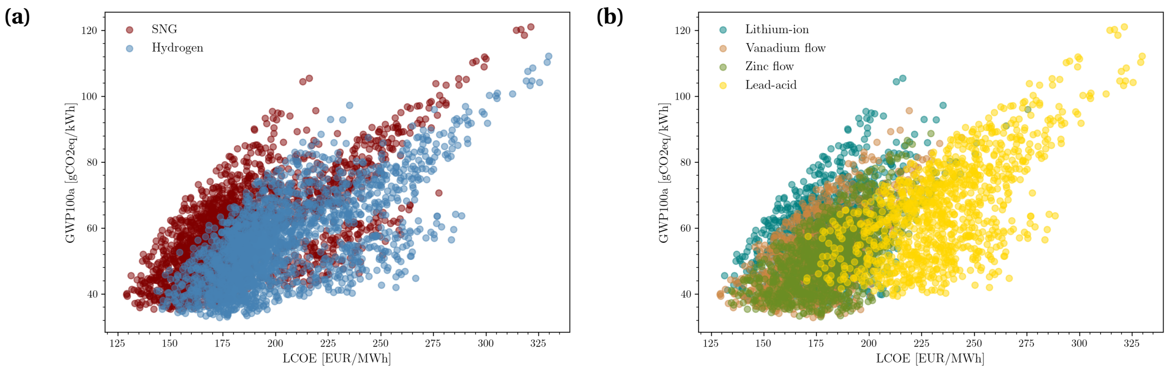

Figure 3.4.1 – Simulated solutions obtained for all Europe assuming interconnected grids between countries. The solutions are scattered with respect to the Levelized Cost of Electricity (LCOE) [EUR/MWh] and Global Warming Potential (GWP100a) [gCO_2eq/kWh]. **(a)**, power-to-gas technologies: Synthetic Natural Gas (SNG) and hydrogen. **(b)**, types of battery: lithium-ion, lead-acid, vanadium and zinc flow.

3

The bounds of the Sobol parameters must be accurately pre-defined to avoid convergence to infeasible solutions. This happens when at least one of the installed generation capacities exceeds its available potential. For this reason, the minimum and maximum bounds of the Sobol variables are defined using the current and potential generation capacities (Equation 3.24). This ensures that, at the initial state of the simulation, each resource capacity is at least equal to the current installation and lower than the available potential. Although the initial state is always a feasible scenario, the algorithm iteratively scales the generation and storage profiles, leading to possible unfeasibilities. More than 110,000 simulations are collected, including solutions with curtailments (Chapter 4). After each run, the converged scenario is checked against the potential capacities and the infeasible solutions are marked as invalid.

$$m_g = \begin{cases} 1, & \text{if } PC_g = CC_g \\ \text{Sobol draw from } [1, \frac{PC_g}{CC_g}], & \text{otherwise} \end{cases} \tag{3.24}$$

Pareto-efficient solutions

At the end of the simulation the set of Pareto-efficient solutions can be extracted by applying Algo. 2 to the ensemble of scenarios. The algorithm returns the set of non-dominated solutions from which the *knee point* is identified by selecting the solution that minimises the element-wise multiplication between the normalised LCOE and GWP100a. The knee point is considered as one of the possible best solutions; the rest of the Pareto-efficient points are also taken into account by analysing different designs and performing uncertainty analysis.

Algorithm 2 Pareto-efficient solutions selection.

```
procedure PARETO-EFFICIENT
    LCOE, GWP100a ← get values                                   ▷ read data from Sobol simulations
    costs ← column stack (LCOE, GWP100a)                          ▷ build N × 2 array
    is_eff ← ones-filled array with shape[0] of costs             ▷ N × 1 boolean array
    for c ∈ costs do
        i ← get index of c
        if is_eff[i] then
            is_eff[is_eff] ← any costs[is_eff] < c               ▷ check if dominated
            is_eff[i] ← True                                      ▷ save index of non-dominated solution
        end if
    end for
    pareto_eff ← (LCOE[is_eff[i]], GWP100a[is_eff[i]])
    return pareto_eff
end procedure
```

3

3.5 Key performance indicators

Levelized Cost of Electricity

The Levelized Cost of Electricity (LCOE) is used to compare the economic competitiveness of the simulated scenarios and determine the minimum market price for which the investments become profitable. This metric is calculated by equalising the net present value (NPV) of all cash inflows from electricity sales to the NPV of all costs over the system lifetime (Eq. 3.25). Capital and maintenance costs are taken into account and the LCOE is measured in Euro per MWh of consumed electricity,

$$\text{NPV of cash inflows over lifetime} = \text{NPV of total costs over lifetime} \tag{3.25}$$

$$\sum_t \left(\frac{\mathrm{LCOE}_t}{(1+i)^t} \times C_t \right) = \sum_t \left(\frac{\sum_g Capex_g + Maint_g(t) \, + \sum_s Capex_{s,t} + Maint_{s,t}}{(1+i)^t} \right) \qquad g \in \mathbf{GT},\ s \in \mathbf{ST},\ t \in \mathbf{T} \tag{3.26}$$

where **GT** and **ST** are the set of generation and storage technologies, respectively. **T** is the ordered sequence of years $\langle 0, ..., t_n \rangle$ and t_n the assumed project lifetime (20 years). The sequence of years starts from $t = 0$, meaning that the initial investment is not discounted. The discount rate i is taken from the cost guide provided by the European Commission [121], the expected facility life in years of the generation technologies from the Lazard estimates [97] and the cost analysis is provided by the IRENA [84]. Eq. 3.26 can be rearranged leading to the final formulation of the LCOE, as shown in Eq. 3.27.

$$\text{LCOE} = \frac{\sum_t \left(\frac{\sum_g Capex_g + Maint_g(t) + \sum_s Capex_{s,t} + Maint_{s,t}}{(1+i)^t} \right)}{\sum_t \frac{C_t}{(1+i)^t}} \quad g \in \mathbf{GT},\ s \in \mathbf{ST},\ t \in \mathbf{T} \tag{3.27}$$

It should be noted that the LCOE is discounted over the system lifetime, in such a way that cash inflows are preferred in earlier years. A reduction factor of 1.73 should be used whenever comparing the presented LCOE estimates to those of studies in which such discounting is not considered. Moreover, the LCOE obtained from Eq. 3.27 is dependant on the selected interest rate (i), whose value is strictly connected with the available financing instruments. High discount rates favour production technologies with long installation times and costs that are more evenly spread over the lifetime. On the contrary, they hinder the competitiveness of renewable installation projects, which usually require high initial investment, but almost negligible costs in later years [122]. For this reason, particular care should be taken whenever comparing the LCOE resulted from this study to those obtained in other research work. Contextualisation of methods and analysis of assumptions should always be performed to avoid misleading conclusions.

Equivalent Annual Cost

The Equivalent Annual Cost (EAC) is used to quantify the cost of owning, operating, and maintaining the energy system over its lifetime. This financial metric can be calculated by annualising the NPV of all costs using the annuity factor (Eq. 3.28 and 3.29).

$$\text{EAC} = \text{Annuity factor} \times \text{NPV of total costs over lifetime} \tag{3.28}$$

$$\text{EAC} = \frac{i(1+i)^{t_n}}{(1+i)^{t_n} - 1} \times \sum_t \left(\frac{\sum_g Capex_g + Maint_g(t) + \sum_s Capex_{s,t} + Maint_{s,t}}{(1+i)^t} \right) \quad g \in \mathbf{GT},\ s \in \mathbf{ST},\ t \in \mathbf{T} \tag{3.29}$$

Environmental impact assessment

The environmental impact assessment of the scenarios is performed using a life-cycle approach with locally differentiated impact factors of the generation resources. Different indicators such as renewable energy (RE) share (method 1 and method 2), climate change (GWP100a and GWP20a) [123], ecological scarcity [124] and ecological footprint are calculated using local data-sets downloaded from Ecoinvent [41] (see Tabs. A.1.1, A.1.2, A.1.4, A.1.5, 1.2.1). While the first method of the RE share indicator associates 100% clean energy use with renewable sources, method 2 accounts for the actual cumulative energy demand over the entire technology life-cycle. Given its more descriptive nature, the second method is selected to quantify the renewable penetration. Moreover, the impact associated with battery [125–132] and power-to-gas [133, 134] storage is considered by collecting data from different peer-reviewed studies. The GWP100a and GWP20a of storage is obtained using the GHG protocol of the IPCC Fifth Assessment Report and the medians of the data distributions are used as deterministic impacts (Tab. C.4.1).

Impact of the current system

The environmental performance of the simulated solutions is compared to the indicators associated with the current energy system to assess the improvements of the generated results. A database of historical grid impacts is constructed using the dynamic LCA tool presented in Chapter 1. Such a tool uses data provided by the ENTSO-E database [3] to quantify the impact of electricity consumption in each European country. It considers hourly electricity production mixes, electrical power exchanges across borders and local impact factors of the energy resources to calculate environmental indicators for each country with a data granularity of one hour (Tab. C.4.2). The impact of households and service heating and transportation sectors is included using the GHG emissions and final energy consumption measures provided by Eurostat [60] (Tab. C.4.3).

Moreover, it should be pointed out that showing how the impact factors of the generation technologies will decrease after achieving a 100% renewable grid is beyond the scope of this study. The focus is on quantifying the environmental impact generated by such a system in an overnight building approach. Since the transition from current to renewable generation is disregarded, impact factors are assumed equal to those associated with the present-day energy technologies. While different strategies are available, this approach is based on proven and current data rather than including additional speculative predictions which could unfairly bias the results. It is also consistent with the data and methods that are commonly adopted in impact assessment studies.

3.6 The future energy system of Europe

The findings show that the projected generation mix is significantly influenced by both local capacity factors (Fig. 3.6.2) and climate change potentials associated with each technology. Starting with hydro power, the potential of run-of-river is largely exhausted in Europe – about 75% of the potential is already installed (Tab. C.1.4). Conversely, investments in hydro reservoirs are still required. The simulations show that Sweden and Austria rely heavily on dams, with generation shares of 64% and

49%, respectively. Other countries such as France (12%), Italy (12%) and Switzerland (20%) increase the share of hydro power from reservoirs given the particularly favourable capacity factor (0.24-0.63) and low global warming potential (6.17 gCO_2eq/kWh) associated with such technology (Tabs. C.1.3 and A.1.2). Solar-based generation is mostly present in countries with limited or no access to offshore resources. Belgium, Slovenia and Switzerland power their future grids with electricity from solar, which accounts for 76%, 65% and 45% of their total generation, respectively. Southern countries with high solar capacity factor (0.14-0.18), such as Bulgaria, Greece, Portugal and Spain, cover more than 10% of their demand using PV.

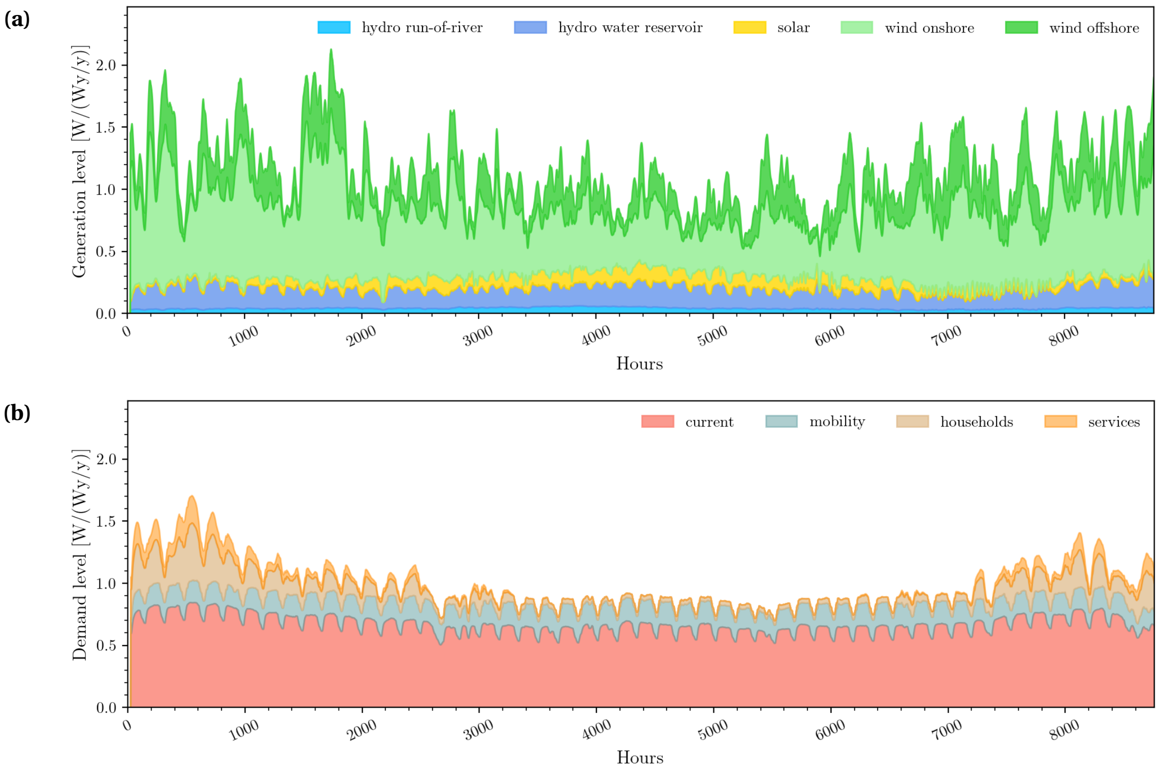

Figure 3.6.1 – Hourly electricity production **(a)** and demand profiles **(b)** for all Europe assuming interconnected grids between countries. Results obtained for the best observed solution. The hourly values are given as a fraction of the yearly average consumed power [W/(Wy/y)]. To smooth out the fluctuations of the electricity profiles and improve the visualisation of the results, 24-hours rolling means are used. **(a)**, electricity production by generation technology with shares: 3.8% hydro run-of-river, 14.2% hydro reservoir, 6.8% solar photovoltaic, 52.6% wind onshore and 22.7% wind offshore (Table C.5.1). The total corresponding produced electricity is 4996 TWh (Table C.5.2). **(b)**, electricity consumption by sector with shares: 67.0% current, 17.4% mobility, 11.6% households and 4.0% services. The associated annual electricity demand is 4406 TWh (Table C.1.5).

Increased additions of wind onshore (+939GW) and offshore (+431GW) lead wind-based technologies to become the predominant source of renewable electricity in Europe with 73% of the total electric power (Tabs. C.5.1 and C.5.3). Czechia, Hungary and Slovakia mostly exploit their onshore wind potential, resulting in land-based wind power reaching a market share greater than 85%. Ireland (80%), Lithuania (72%) and Poland (81%), despite their access to offshore wind, favour cheaper onshore generation (Tab. C.5.4). Alongside onshore wind, the deployment of wind farms situated offshore is paramount in reaching the 100% clean electricity target. Although offshore wind is costlier than other renewable installations – 100%, 29%, 58% more expensive than combined hydro, PV and wind onshore, respectively (Tab. C.5.5) – it becomes a significant part of the European power generation sector (about 25% of total energy output). Germany installs almost the totality of its potential (98%), adding more than 95GW to its current capacity. Similarly, France fully replaces nuclear power plants with offshore turbines that account for 55% of the total generation. Finally, the Netherlands supply 91% of the annual electricity demand using cost-competitive generators located in coastal and deep-water areas.

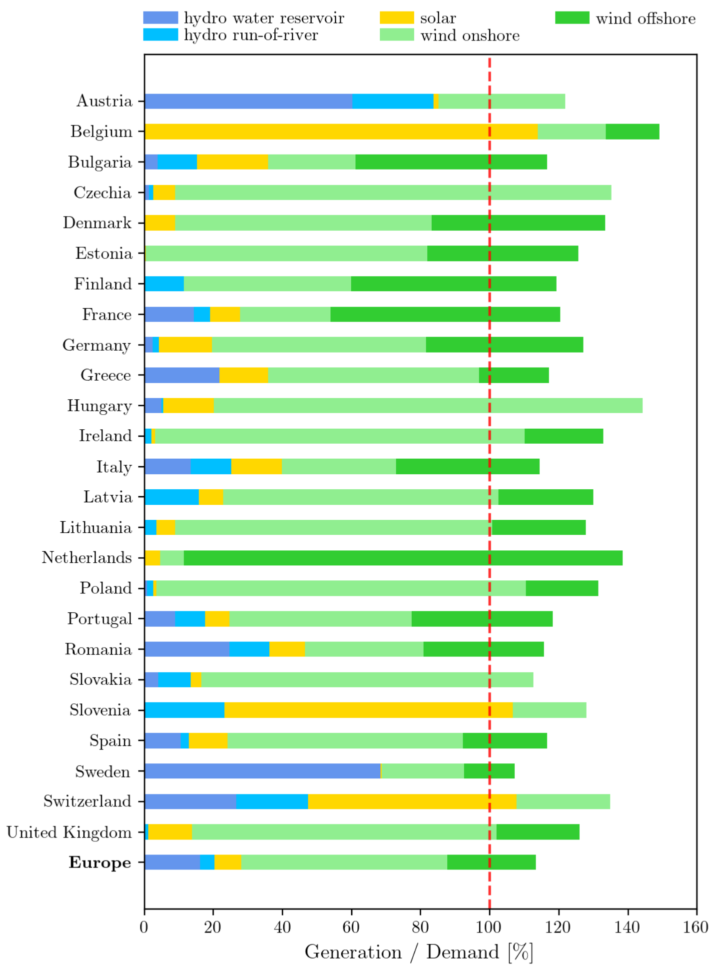

Figure 3.6.2 – Electricity generation from the installed technologies. The figure shows how countries overbuild capacity to compensate for storage losses – annual generation as share [%] of the consumption (Table C.5.2).

Electricity demand and wind availability

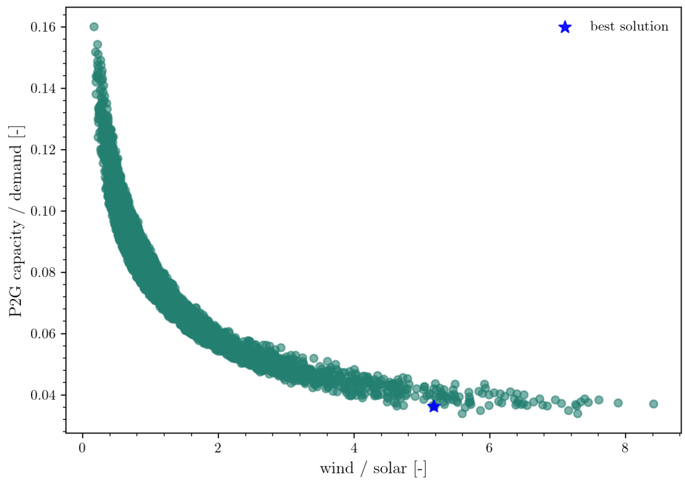

Figure 3.6.3 – P2G capacity (fraction of demand [-]) as a function of the wind to solar ratio [-]. The star marker locates the best observed solution, namely the best LCOE/GWP100a trade-off.

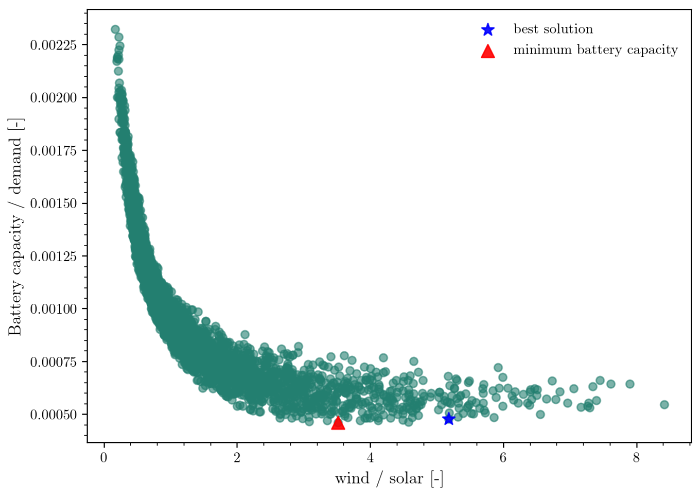

Figure 3.6.4 – Battery capacity (fraction of demand [-]) as a function of the wind to solar ratio [-]. The star point identifies the wind to solar ratio for which the battery has the lowest capacity.

Along with the growing use of renewable energy, electricity demand is set to increase (+51%) as a result of electrification of transport and heating in the household and service sectors (Tab. C.1.5). The large-scale deployment of heat pumping for space heating and hot water causes an imbalance of the seasonal consumption, introducing changes to the long-term variability of the electricity demand (Fig. 3.6.1b). This increasing weather dependency, together with the negative correlation between wind and solar output at seasonal timescale, partially explains the selection of wind-based generation as the primary source of electricity. The capacity factors of onshore and offshore wind increase by 76% (0.186-0.331) and 33% (0.369-0.490) from summer to winter, respectively, while the output from PV decreases by 48% (0.116-0.060) due to sustained low-sun conditions in the cold season. As a result, additional investment in wind generation allows to better match consumption with production, therefore reducing the need for long-term storage (Fig. 3.6.3).

Electricity storage profile and requirements

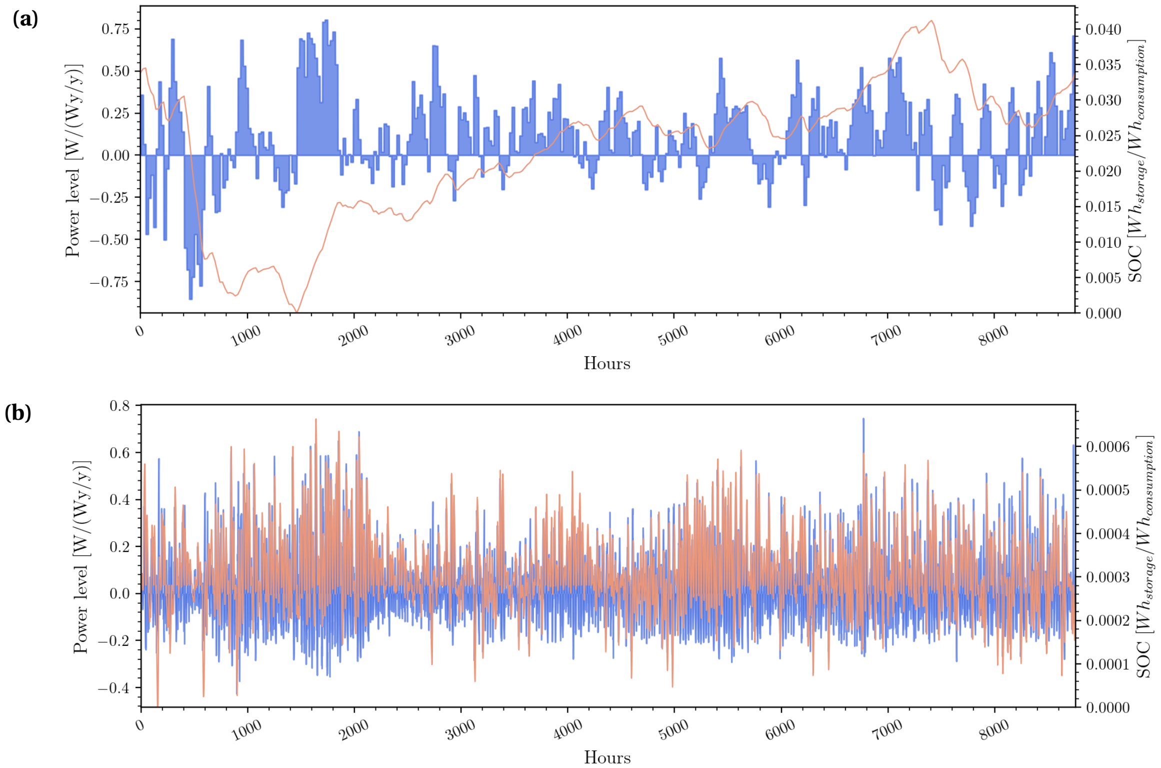

Figure 3.6.5 – Hourly long- **(a)** and short-term **(b)** storage profiles for all Europe assuming interconnected grids between countries. Results associated with the generation and demand profiles of Figure 3.6.1. **(a)**, power levels (in blue) and State of Charge (in red) of the SNG storage with total capacity of 160 TWh. **(b)**, vanadium flow battery with total capacity of 2 TWh. The power level and the SOC are given as fraction of the yearly average consumed power [W/(Wy/y)] and annual electricity consumption [Wh/Wh], respectively (Table C.6.1). The storage charging time, calculated as percentage [%] of the annual operating time, and the annual electrical energy that is sent to storage, expressed as share [-] of the electricity demand, are shown in Table C.6.2 and C.6.3.

With the European renewable generation capacity reaching record levels, storage technologies are crucial to displacing electricity from excess to deficit period without resorting to fossil fuels. Grid-scale battery facilities can be used to compensate for power shortfalls and over-production peaks of intra-day periods (Fig. 3.6.5b). Such power fluctuations, which are typically due to sudden changes in weather conditions, are crucial for the correct design of the battery system. Conversely, longer trends in weather require the storage of larger electricity amounts, which must be released afterwards to maintain the grid balance during multi-day and seasonal periods of deficit (Fig. 3.6.5a).

The results show that countries relying on solar generation always require larger installations of long-term storage facilities because of the strong seasonal cycle in irradiance. This is the case for Belgium (Fig. C.7.2a) and Switzerland (Fig. C.7.24a), both requiring a record capacity of power-to-gas greater than 20% of the annual electricity demand (Table C.6.1). Unlike solar, the seasonal wind variability is significantly weaker at 35% lower on average (Table C.5.6). As a result, the need for P2G decreases in countries with high wind penetration, as in the case of Slovakia, where the installed capacity equals 4.3% of the electricity demand.

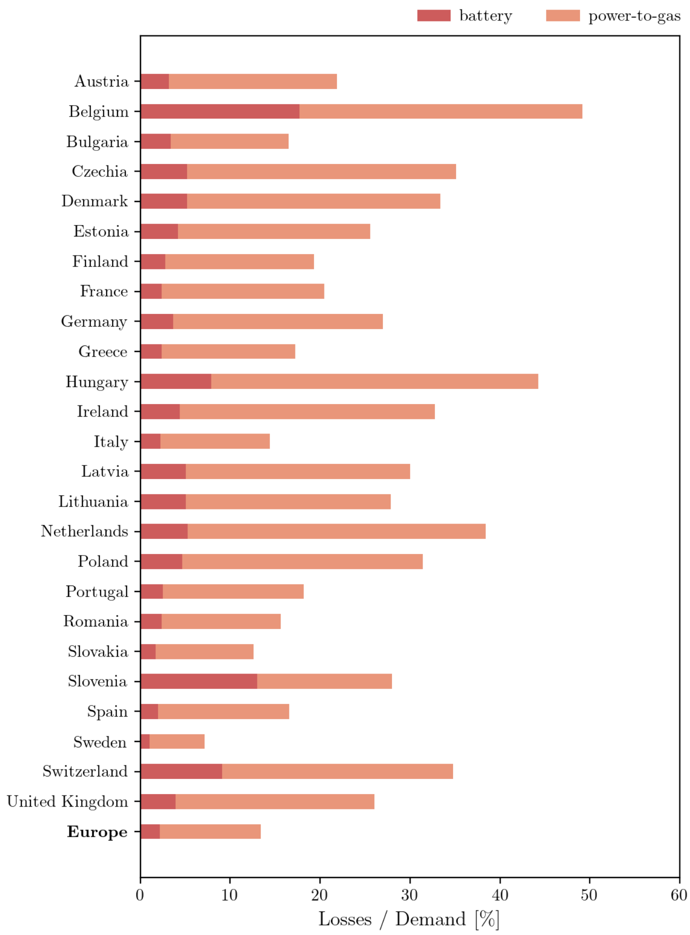

Figure 3.6.6 – Electricity losses due to storage. The electricity lost during the charge and discharge phase of the long- and short-term storage as share of the demand [%] (Table C.10.4). Excess generation losses range between 7% of the annual demand in Sweden to 49% in Belgium, while it is 14% in the case of an interconnected Europe. Power-to-gas accounts on average for more than 84% of the total electricity losses.

Wind and solar complementary patterns

The all-country average variability of solar on an hourly basis almost doubles that of combined onshore-offshore wind. Such high variability due to large PV installations leads to significant intra-hour ramps in power load that must be absorbed by fast-response batteries. This is demonstrated for Belgium and Hungary, where short-term storage achieves the highest relative capacity among all the European countries (0.26% of demand). At the same time, increasing the number of solar installations relative to wind reduces the hourly variability of the total power for wind-to-solar capacity ratios above a certain threshold (Fig. 3.6.4). In most countries, wind and solar have complementary diurnal and seasonal production profiles, which can be exploited to reduce the overall need for storage. Such use of PV panels to compensate for shortages in wind power throughout the year has to be carefully balanced against the risk of increasing seasonality.

3.7 Self-sufficiency potential of renewable electricity

This work estimates that the European renewable potential exceeds the projected demand by more than six times (Fig. 3.7.1). Solar PV and onshore wind are sufficient to cover the entire consumption alone, with each technology able to supply more than 10,000 TWh of electricity per year. Although the technical potential is higher than demand in every country, it is unequally distributed in Europe (Figs. C.8.1, C.8.2, C.8.3, C.8.4, C.8.5). Italy accounts for over 30% of the hydro potential from rivers, France alone has more than 20% of the potential capacity for both solar and onshore wind, while offshore wind availability is significantly higher (>30%) in the United Kingdom. When normalising by national demand, solar and wind potentials reach particularly high levels in the Baltic countries, Ireland and Romania, with annual generation potentials comprised between 10 and 25 MWh of electrical energy per MWh of consumption (Tab. C.8.2). Overall, the aggregated potential of all renewable resources in Latvia exceeds the country demand 44 times, whereas it is only 10%, 44% and 60% higher than the annual consumption in Belgium, Slovenia and Switzerland, respectively (Tab. C.8.4).

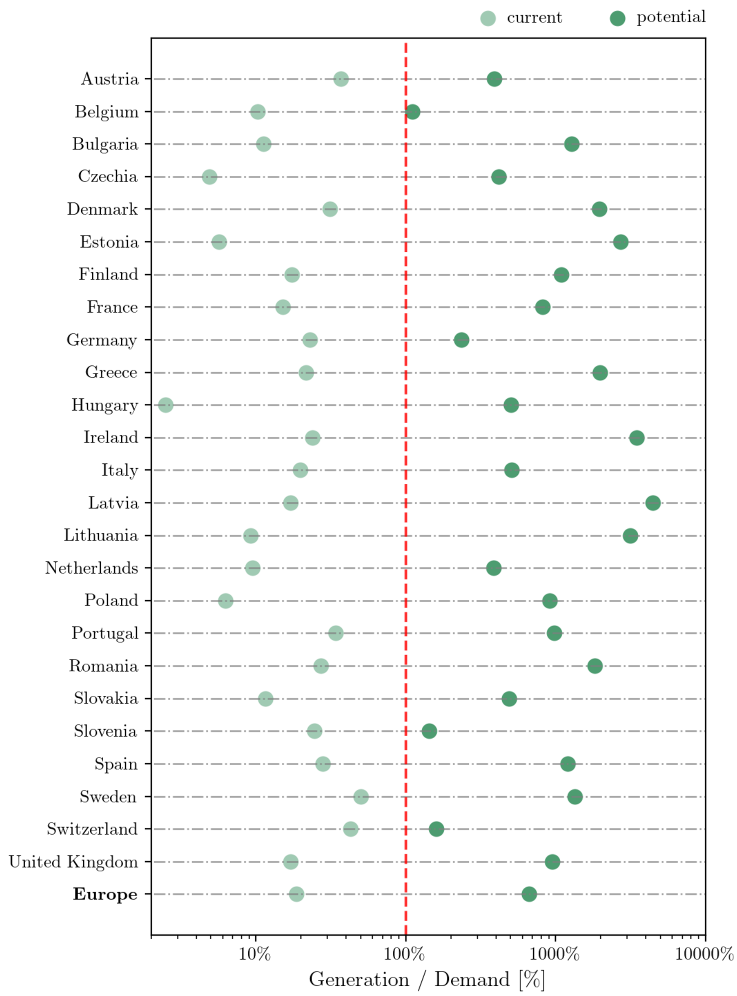

Figure 3.7.1 – Current (Table C.1.2) and potential generation (Table C.1.4) as share [%] of the electricity demand per country and all Europe. The red dashed line represents the electricity self-sufficiency. The figure shows the solutions without storage, hence the demand equals the annual electricity consumption. Countries with a potential generation share that is lower than 100% cannot achieve a fully renewable generation mix – point on the left side of the self-sufficiency line. The results are gathered in Table C.8.4.

Self-sufficiency with storage

While renewable resources are abundant in Europe, the potential-to-demand ratio decreases by 12% if considering storage (Fig. 3.7.2). Losses due to charging and discharging of power-to-gas and batteries reduce the self-sufficiency capability of all countries, leaving only Belgium unable to achieve power autonomy; here, the considerable requirement for storage leads to a potential generation able to cover only 74% of the national demand. Further installation of solar panels exceeding the potential by 50% (Tab. C.8.5) would allow Belgium to be as self-sufficient as the rest of

Europe. This would be possible if the country installed an additional capacity of 50 GW of open field PV, which is not considered in this work.

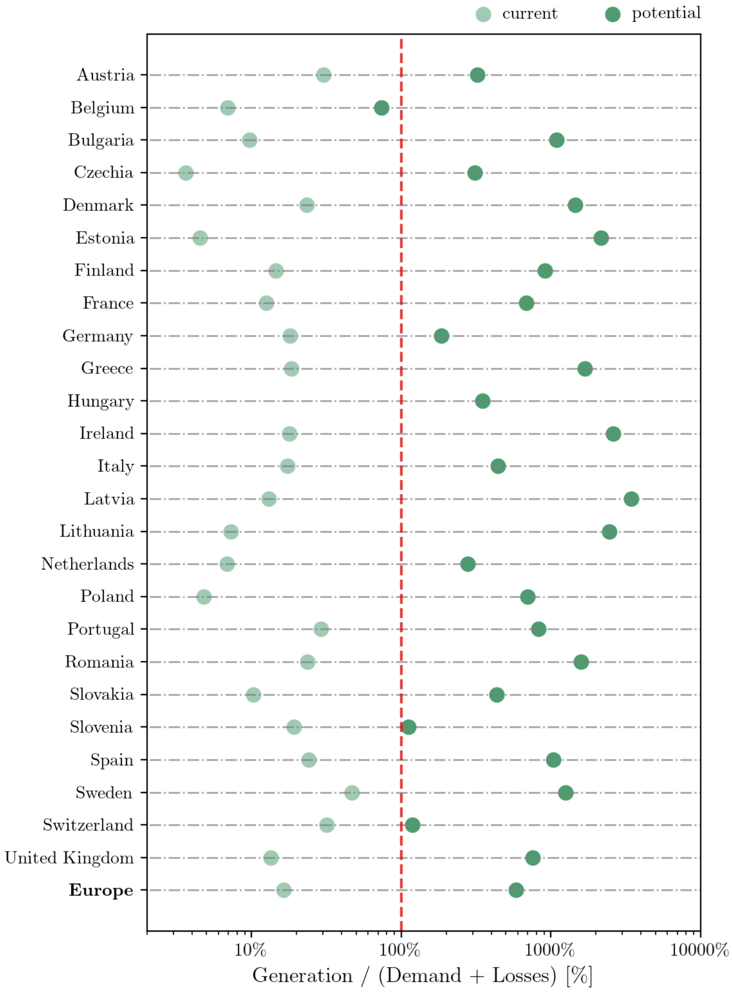

Figure 3.7.2 – Current (Table C.1.2) and potential generation (Table C.1.4) as share [%] of the electricity demand per country and all Europe. The red dashed line represents the electricity self-sufficiency. The results account for the losses of the battery and power-to-gas systems, meaning that the demand is increased by the amount of electricity that is lost during the charging and discharging of the storage.

3.8 The relevance of storage

Oversizing capacity requires massive investments in generation infrastructure and frequent curtailment to ensure constant balancing between consumption and production. As demonstrated, electricity storage significantly reduces the need for over-provisioning solar and wind, albeit not always attainable at the country scale. Fig. 3.8.1 shows that strategies solely based on overbuilt capacity are infeasible in eight European countries (Austria, Belgium, Czechia, Germany, Hungary, Netherlands, Slovenia, Switzerland). More precisely, the uncertain supply of electricity from renewable resources leads to generation that exceeds the renewable potential forty times in Belgium and more than ten times in the Netherlands, Slovenia and Switzerland.

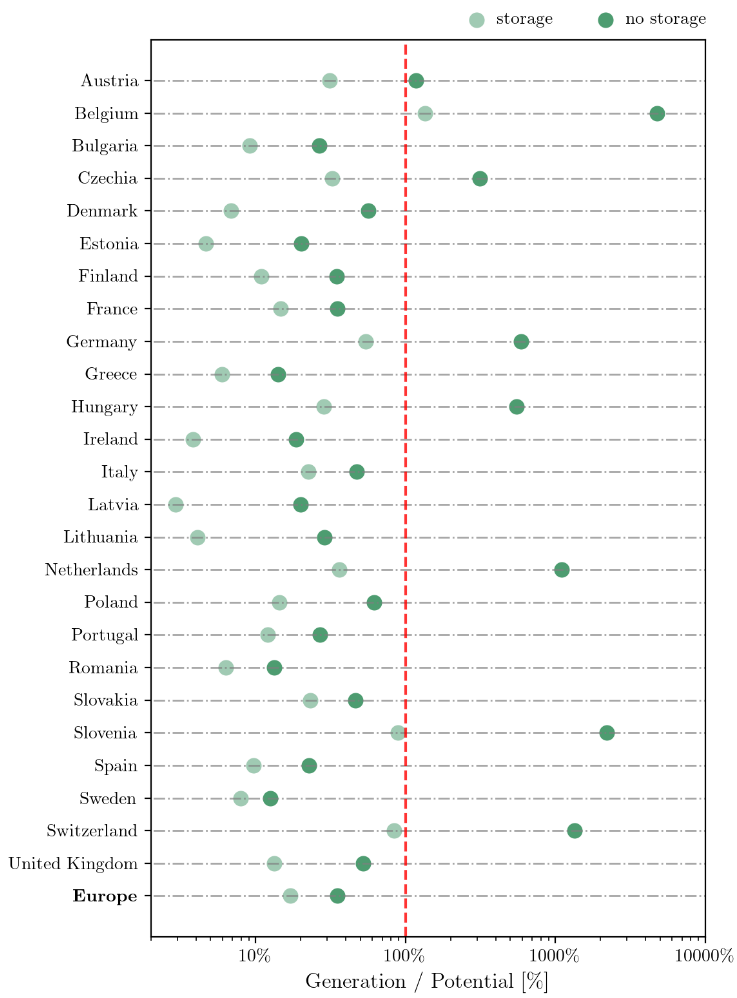

Figure 3.8.1 – Need for overbuilt capacity in Europe (Table C.9.1). The electricity generation given as fraction [-] of the technical potential for solutions with (light points) and without storage (dark points). The results for Europe are obtained assuming interconnected grids between countries, hence cross-border imports and exports of electricity as alternative to storage (dark green). The red dashed line delimits the feasibility domain: points on the right side of the line are technically unattainable.

While being technically unattainable at national level, resource requirements for overcapacity are less significant at the continental scale. An interconnected Europe could potentially reduce the need for storage through the adoption of a grid operating strategy based on curtailments of excess generation. However, such an approach would entail higher environmental impact compared to solutions based on combined storage and power exchanges. The inclusion of electricity storage in the European power grid reduces overcapacity by a factor of two: 17% of continental generation potential would be needed instead of 35%. Moreover, decarbonization strategies based on long- and short-term storage with cooperating grids are associated with 33% lower emissions compared to overbuilt solutions with exchanges (Fig. 3.8.2). Such an environmental benefit increases even further at country scale, with Denmark, Latvia and Lithuania able to decrease their carbon emissions by 75% if choosing storage – a six-fold decrease in the required generation capacity (Table C.9.1).

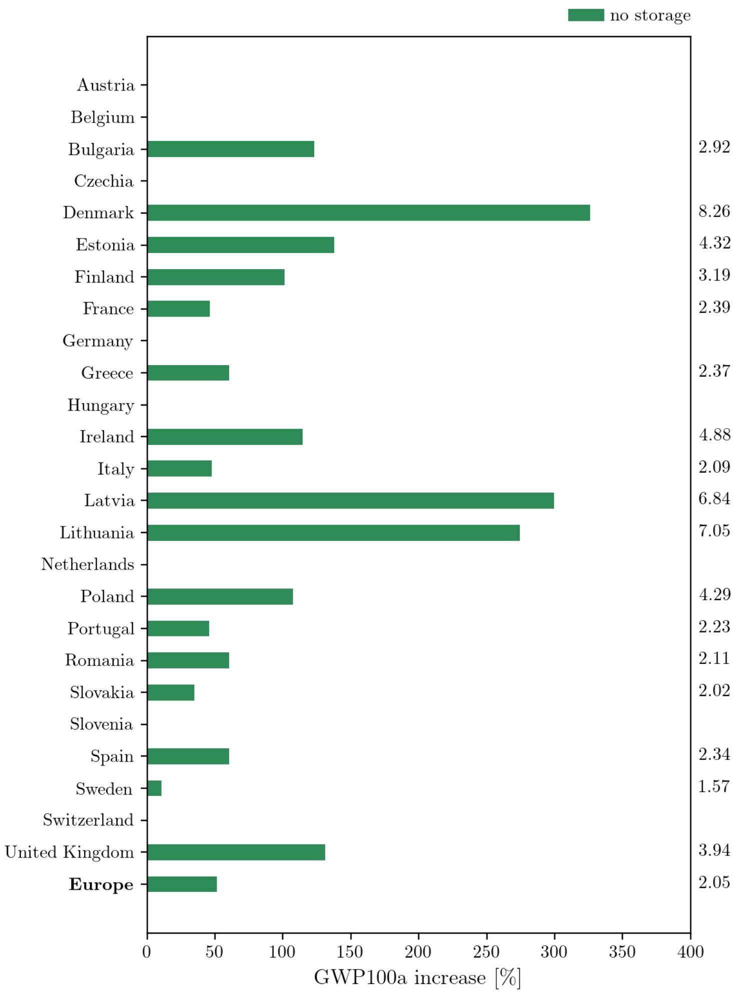

Figure 3.8.2 – Environmental benefit of electricity storage versus overbuilt capacity in Europe (Table C.9.1). Impact of over-capacity investments on climate change as percentage increase of the Global Warming Potential (GWP100a) from the optimal scenario with storage (Table C.10.1). The results are shown only for the solutions in the feasible domain: countries exceeding their potential are disregarded. The generation oversizing factors are displayed on the right side of the figure.

3.9 The cost of a 100% renewable Europe

Onshore and offshore wind power [135, 136] and photovoltaics [137] are the resources offering the highest renewable potential in Europe [54]. Grid parity is achievable through proper generation site selection alongside optimised generation capacity, storage size and cost. Jacobson et al. [138] showed a fully renewable energy system with a LCOE between 61 EUR/MWh (for Norway) and 159 EUR/MWh (for Luxembourg) and an average value of 83 EUR/MWh for Europe. This value reviews the 100 USD/MWh previously attained for Europe proposed by the same author [139]. 64.5 USD/MWh is the LCOE for a fully renewable US (states considered independently) while disregarding storage [140]. In a recent study by the Fraunhofer Institute for solar energy systems [141], the LCOE of different renewable technologies was discussed. High uncertainty affects the future cost of these technologies in Germany; projections for hybrid PV and battery systems fall below 120 EUR/MWh and wind power costs go up to 83 and 121 EUR/MWh for onshore and offshore, respectively. The European projections point for onshore wind power plants between 31 and 49 EUR/MWh and 54 and 80 EUR/MWh for offshore ones, omitting exact location.

LCOE of generation technologies

The LCOE of each production technology is evaluated based on hourly capacity factors, obtained from the actual generation profiles in a country-dependent approach. As a result, the LCOE of solar, wind and hydro power markedly changes by country (Fig. 3.9.1), motivated by geographical differences (e.g., resource availability). Hydro power generation cost from water reservoirs (average: 57 EUR/MWh) has the highest variability, with values ranging between 28 (Italy) and 165 EUR/MWh (Slovakia). Run-of-river supplies electricity at a more stable price with 40% decrease in LCOE variance compared to reservoirs, an economically advantageous power source in Switzerland (44 EUR/MWh) and the least attractive one in Spain (143 EUR/MWh). Overall, power generation from hydro resources remains very competitive, producing electricity at lower cost than solar and wind in two-thirds of Europe.

The cost of solar photovoltaic is considerably lower in southern countries due to favourable climatic conditions. Solar panels can be installed in Spain for as little as 68 EUR/MWh – slightly more than 70 EUR/MWh in Greece and Portugal. Northern countries such as Ireland, Poland, Finland and Sweden require higher electricity prices for newly commissioned solar installations, reaching 130 EUR/MWh. Onshore wind generation is the least expensive in Lithuania, where in-land turbines can provide low-cost power at 65 EUR/MWh, whereas the most expensive can be found in Switzerland, Belgium and Slovenia (93, 96 and 131 EUR/MWh, respectively) (Tab. C.5.5).

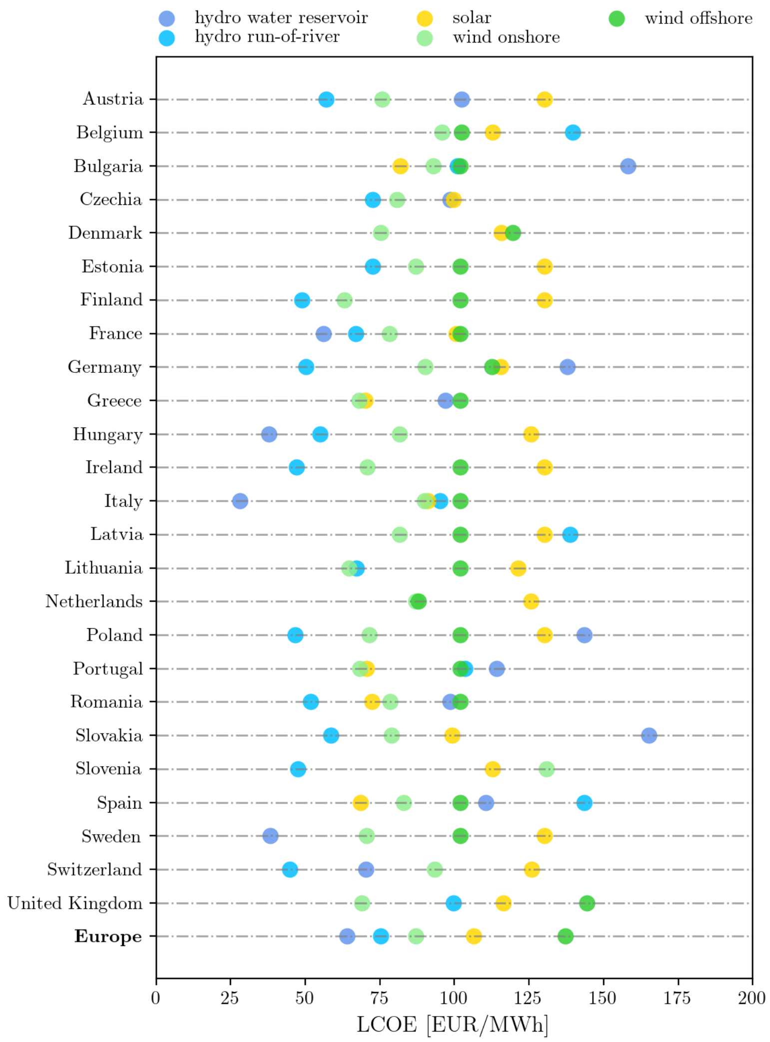

Figure 3.9.1 – Levelized Cost of Electricity (LCOE) [EUR/MWh] of generation technologies by country and all Europe (Table C.5.5). The price is calculated at the generation side, hence the amount in Euro is given per MWh of produced electricity. The results refer to the best observed simulations.

System LCOE and costs breakdown

Battery and P2G are also included in the calculation of the system LCOE. The economic competitiveness of battery storage is significantly connected to the simulated operating strategy, which reflects a typical use for energy arbitrage, with the capacity factor ranging between 1% and 2.5% on an hourly basis (Tab. C.10.5). The cost of electricity storage in Europe accounts for 30% of the global LCOE (Fig. 3.9.2), with batteries accounting for two-thirds of that share. More than 50% of total cost is due to combined onshore and offshore wind generation; the remaining 20% arises from additions in solar and hydro capacity (Tab. C.10.2). Exceptions must be pointed out on a country basis, such that the presence of a predominant technology in the generation mix can significantly influence the required price of electricity. More specifically, the share of solar PV on the system cost exceeds 38% in Belgium, Slovenia and Switzerland, while wind-based generation is particularly high in Slovakia and the Netherlands, where onshore and offshore turbines account for more than 60% and 50% of the total LCOE, respectively. Capital expenditures are the largest contributor to the system lifetime costs, accounting on average for more than 80% of the system LCOE (Tab. C.10.3).

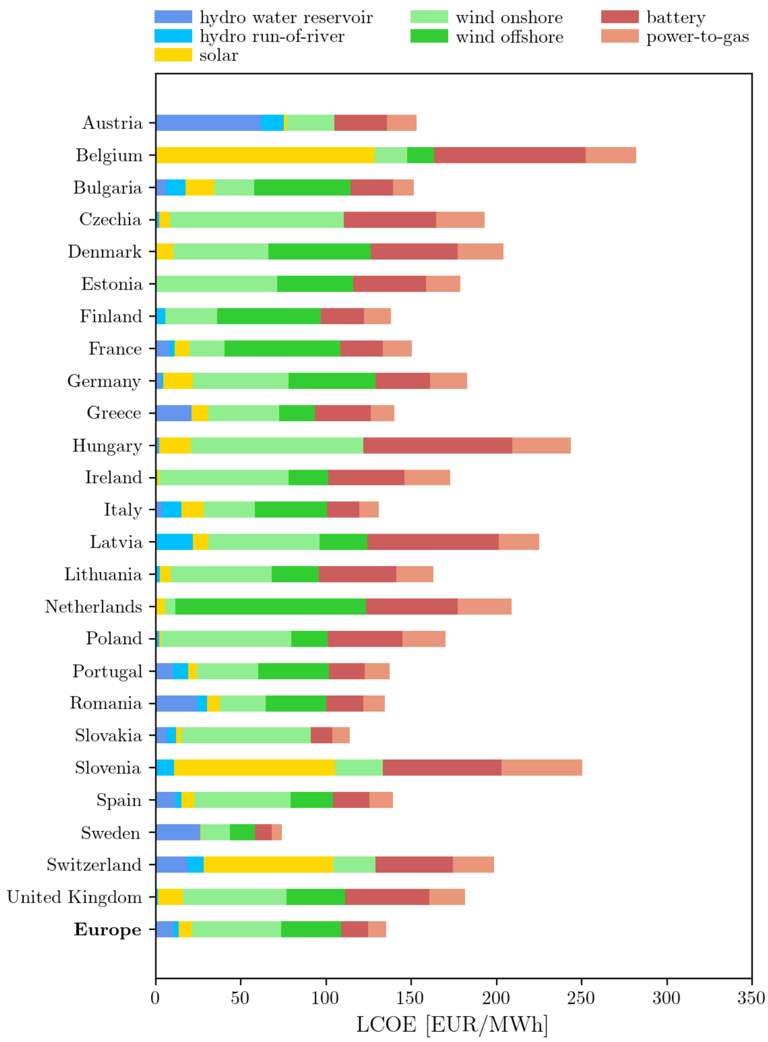

Figure 3.9.2 – Levelized Cost of Electricity (LCOE) [EUR/MWh] by country and all Europe. Stacked contributions of each electricity production resource and storage to the LCOE of the whole energy system (Table C.10.2). The storage losses are accounted, therefore each contribution represent the price in Euro per MWh of consumed electricity. The results refer to the best observed simulation.

3.10 Discussion

The analysis of the overall results reveal that the best trade-off designs install significantly lower PV capacity compared to other studies [54, 142]. This is due to the approach used for the selection of the best designs, defined as solutions that minimise the element-wise multiplication between the normalised LCOE and GWP100a. Scenarios with large solar installations are usually associated with a considerably higher environmental impact compared to those predominantly based on hydro and wind resources. As a consequence, PV panels turn out to be less attractive than wind and their use is limited to offsetting shortages in wind, whose production pattern is complementary to solar in most countries.

The cost associated with each scenario is calculated using a formulation of the LCOE based on the discount of all cash inflows and outflows over the system lifetime. However, it should be noted that costs are highly dependent on the assumptions made (i.e. cost sources, interest rate, lifetime, LCOE formulation). For this reason, the LCOE estimated here can significantly differ from those provided in other studies [138–141, 143, 144], especially when discounting cash inflows is not considered. Results and assumptions should be framed when comparing the LCOE from this work with the literature to avoid misleading conclusions.

3.11 Conclusions

The climatic emergency, political treaties and international commitments of the various countries require bold system designs for renewable energy generation and storage. This work establishes a framework for an interconnected electricity grid in Europe, highlighting the importance of short- and long-term storage as well as the needs and contributions of each European country. A simulation-based algorithm coupled with a drawing mechanism from a Sobol sequence is used to consistently explore the space of possible solutions in a Monte Carlo approach. All constructed scenarios are compared in terms of economic and environmental competitiveness using LCOE and GWP100a as primary metrics.

Electrification of future European households, services and mobility sectors is considered to construct energy scenarios that are coherent with the long-term transition pathways identified by the European Commission. As demonstrated, electrification introduces changes to the long-term variability of demand, increasing weather dependency and consequently driving technology choices. Different levelized costs of the generation resources are obtained for each country in a data-driven approach which ensures realistic modelling of the energy system. The findings show that the future generation mix is significantly influenced by local capacity factors, with wind-based technologies designated to become the predominant source of renewable electricity in Europe, with 73% of the total output. Moreover, in several countries wind and solar manifest complementary diurnal and seasonal profiles, leading to reduced need for storage. However, such use of PV to compensate for deficits of wind output must be conscientiously balanced against the risk of introducing seasonal cycles.

Overcoming the natural variability of renewable can be accomplished by either overbuilding generation resources or favouring electricity storage. The results demonstrate that strategies solely based on solar and wind over-provisioning are not always attainable at the country scale. Nevertheless, resource requirements for overcapacity are far less significant at the continental scale when system expansion is considered. An interconnected Europe can potentially substitute storage with a grid design based on excess curtailable generation. However, such a strategy would lead to an increased carbon footprint of electricity (+50%) compared to scenarios relying on storage.

3

An incentivized cooperative scheme for transmission expansion in Europe

How can a grid design based on transmission expansion benefit to the European energy system? What is the economic valued of the energy security service? Can curtailments benefit to cost and emissions?

Overview

- Electrical synergy in the European grids.
- Uncertainty analysis and capacity requirements of electricity storage.
- Effect of curtailments on grid design and storage operations.
- Assessment of environmental benefit of an interconnected Europe and cost of transitioning to a 100% renewable energy system.

This chapter is a preprint version of the article [145] in preparation.

4

Here, the work presented in Chapter 3 is expanded to focus on the benefits of electrical grid interconnections. A comparison between isolated grids and a European interconnected system shows that synergies can significantly decrease energy cost and total greenhouse gas emissions by 18% and 24%, respectively. The same approach introduces a novel way to estimate the price that countries are expected to pay for the security of supply or, instead, their compensation for providing inexpensive renewable energy.

Enhanced features in the simulation algorithm allow investigation of wind and solar curtailment effects on grid design. The results demonstrate that operating strategies based on moderate curtailments (10% - 20%) when grids are interconnected, or harsher ones (20% - 40%) in isolated systems, can benefit both energy cost and emissions. In addition, curtailment is found to mostly improve climate change metrics in countries with high potential and high capacity factors of wind, by preferring overbuilt clean generation over storage. Finally, an uncertainty analysis is carried out on cost, environmental impact and efficiency parameters from probability distribution functions, which are constructed upon data collected from the reviewed literature.

Introduction

Modernising the European power system in a cost-effective way, while coping with environmental standards, is a major challenge. Elucidating the benefits of cooperation among regions can contribute to a more informed and fair discussion. Indeed, the asymmetric distribution of potential capacities from renewables forms the basis for cooperation benefits, but also for an uneven effort between regions. Galan et al. [140] were the first to study the cooperation within the US on economic and environmental grounds. Cooperation prompted a reduction of 12% in LCOE and a further 3% in associated emissions when compared to a non-cooperation scenario. Although cooperation did not achieve a fully renewable energy system, it resulted in an increase of the renewable mix, with wind (both onshore and offshore) representing 35% of the electricity generation. The methodology enables derivation of a compensation scheme to harmonise differences between regions. However, a yearly resolution was used, which prevented the authors from exploring the design and operation of storage units.

Bogdanov et al. [146] studied different world regions, showing economic benefits of synergies between countries and highlighting the use of hydro-electric dams for long-term storage, but mobility was not electrified and environmental metrics were disregarded. Trondle et al. [54] showed that small countries benefit the most with a connected structure when promoting European synergies. Grossmann et al. [20] went further by linking areas in different time zones and hemispheres, claiming that solar energy alone can eliminate the need of any other energy source, provided adequate coordination and transmission lines exist.

Contributions

While increased coordination delivers system-wide cost reductions, the economic advantages are unevenly distributed between participants. This work introduces a novel approach to estimate the economic value of the energy security service by comparing the reduced LCOE in each country to the uniform price of the shared network. The scheme is based on impartial sharing of the monetary benefits that are obtained by transitioning from an independent design with isolated grids to a full interconnected solution in which Europe acts as a single coordinated entity. Moreover, the method builds upon the model and results introduced in chapter 3, hence it implicates a level of details and data granularity which is unprecedented for Europe.

4.1 Simulation algorithm with curtailments

Electricity curtailments are simulated by introducing a factor c, which describes the intensity of curtailment with respect to the maximum excess power (Equation 4.1). This factor assumes values between 0 and 1, with 0 indicating no curtailments and 1 representing a full reduction in output until generation equals demand. Any value between the bounds represents a different curtailing strategy, which is simulated by following a modified procedure of the algorithm as described below.

$$p^{\mathrm{i}}_{hourly,max}(h) = \max\left(p^{\mathrm{i}}_{hourly}(h)\right) \times (1 - c) \tag{4.1}$$

For any given factor c the hourly excess and deficit power is recalculated using the formulation of Equation 4.2. Any excess above the threshold $p^{\mathrm{i}}_{hourly,max}(h)$ is curtailed, while the profile is left unchanged otherwise.

$$p^{\mathrm{i}}_{hourly}(h)^{*} = \begin{cases} p^{\mathrm{i}}_{hourly,max}(h), & \text{if } \sum_g^{\mathbf{GT}} G^{\mathrm{i}}_g(h) - C^{\mathrm{i}}(h) > p^{\mathrm{i}}_{hourly,max}(h) \\ \sum_g^{\mathbf{GT}} G^{\mathrm{i}}_g(h) - C^{\mathrm{i}}(h), & \text{otherwise} \end{cases} \tag{4.2}$$

4

Curtailed power profile

The hourly curtailed power profile $CPP^{\mathrm{i}}(h)$ is obtained by subtracting $p^{\mathrm{i}}_{hourly}(h)^{*}$ from its original shape (Eq. 4.3) and is used to calculate the loss factor $l^{\mathrm{i}}_f(h)$, which represents the percentage of generation that is lost due to curtailments. Eq. 4.4 updates $l^{\mathrm{i}}_f(h)$ at each iteration by dividing the energy loss at hour h by the total electricity output from the curtailable loads, which are specified in set **CGT** (**CGT** $\in$ **GT**). Only solar PV and wind-based generation are considered as curtailable.

$$CPP^{\mathrm{i}}(h) = p^{\mathrm{i}}_{hourly}(h) - p^{\mathrm{i}}_{hourly}(h)^{*} \tag{4.3}$$

$$l^{\mathrm{i}}_f(h) = \frac{CPP^{\mathrm{i}}(h)}{\sum_g^{\mathbf{CGT}} G^{\mathrm{i}}_g(h)} \tag{4.4}$$

Finally, Eq. 4.5 applies the curtailment to the generation technologies by reducing the useful output of each g member of **CGT**. The difference between the actual and useful output allows the calculation of the hourly energy losses by technology ($L^{\mathrm{i}}_g(h) = G^{\mathrm{i}}_g(h) - G^{\mathrm{i}}_g(h)^{*}$), which is used to calculate the share of curtailed generation $SCG^{\mathrm{i}}(h)$ as in Eq. 4.6.

$$G_g^{\mathrm{i}}(h)^* = \begin{cases} G_g^{\mathrm{i}}(h) \times (1 - l_f^{\mathrm{i}}(h)), & \text{if } g \in \mathbf{CGT} \\ G_g^{\mathrm{i}}(h), & \text{otherwise} \end{cases} \tag{4.5}$$

$$SCG^{\mathrm{i}}(h) = \frac{\sum_g^{\mathbf{CGT}} L_g^{\mathrm{i}}(h)}{\sum_g^{\mathbf{CGT}} G_g^{\mathrm{i}}(h)} \tag{4.6}$$

The equations described in this section allow the modelling of different curtailing strategies, which are only dependant on the intensity of curtailments c. Once a strategy is selected, the simulation algorithm designs the energy system by following the same procedure described in Chapter 3.

Moreover, it should be noted that the model allows scenario simulation solely based on overbuilt generation capacity. This is possible by setting a curtailment factor equal to unity, in which case the algorithm always converges to a solution with no storage. This approach is used to assess the benefit of storage in reducing the need for over-provisioning solar and wind. A higher convergence tolerance shall be used in this case (e.g., 5% instead of 1e−5% of the annual demand) to avoid solutions that are excessively dependent on the selected meteorological year or influenced by error outliers in the background data.

4.2 Data uncertainty

Uncertainty of costs and storage efficiencies

The capital and maintenance costs of generation and storage technologies are a source of uncertainty. Probability distribution functions, based on empirically constructed formulations, are employed to model them. The best-fit distributions are identified by comparing data, collected from literature (Tabs. D.1.1 and D.1.2), with a set of hypothetical functions (null hypothesis in statistical testing) using the Kolmogorov-Smirnov test [147]. This non-parametric method verifies that a given set of discrete samples has been selected from a population with a known cumulative distribution function. The level of correlation is assessed by the p-value, a statistical quantity [0,1] that describes how close the empirical data are to the tested distributions in terms of mean, variability and shape. The reference function that maximises the p-value among the tested ones is selected as the best fit.

A pool of distributions is constructed by selecting probability functions that are commonly used in cost analysis. Most of the distributions used are non-zero and positively skewed, hence representative of price levels. The distributions are: Normal, Log-normal, Chi, Chi-squared, Exponentiated Weibull, Weibull maximum, Weibull minimum, Pareto Type II or Lomax, Generalized Extreme Value

(GEV), Power-function, Power Log-normal, Power Normal, Beta and Uniform. Finally, whenever the data are insufficient to fit a function with a p-value greater than the significance level (0.1), a uniform distribution of the variable defined between the minimum and maximum available samples is assumed. The same approach is applied to characterise the uncertainty of the storage efficiency (Table D.1.3).

Uncertainty of environmental impact factors

The uncertainty of the environmental impact factors is described by log-normal distributions centred around the deterministic values of the same impacts [41]. The variance of the underlying normal distribution is constructed by summing the basic uncertainty, which reflects errors due to inaccuracy in measurements and time fluctuations, and an additional term that represents the reliability of the data sources. Raw data used in the definition of an impact factor are sometimes outdated, geographically uncorrelated or even assumed from other technologies. While the basic uncertainty can be obtained from the quality guidelines provided by Ecoinvent, the additional term is calculated using a pedigree matrix, which divides the inaccuracy of the data sources into five contributions (Tab. D.1.4). Once the geometric mean and the variance are defined, the uncertain impact factors of the generation resources are randomly drawn from the log-normal function. Since the Ecoinvent database does not provide any impact factor for the considered storage technologies, the same approach used for the cost was adopted to quantify the uncertainty associated with the Global Warming Potential (GWP100a) of storage (Tab. C.4.1).

Once all the distributions of the uncertain parameters are constructed, an uncertainty analysis is performed on the Pareto-efficient solutions to simulate possible evolution of events which can lead to different storage requirements. The cost and emissions associated with each uncertain scenario are recalculated to assess the uncertainty range of the metrics. About 2.5 million new data points are collected for the base scenarios (no curtailments) and the same number of solutions with curtailments.

4.3 Limitations

The present work focuses on the high-level design of the European energy system while neglecting the decentralised availability of resources at the sub-national scale. Consequently, neither isolated nor interconnected grids account for local requirements of investing in grid reinforcement that might be necessary in areas with high concentration of renewables. Although limited by the availability of data, the inclusion of detailed information about regional potentials would allow estimation of reinforcement needs, leading to more accurate cost calculations.

All proposed designs are constructed using 2019 as the typical meteorological year (TMY). Therefore, the results might be over-influenced by the specific weather phenomena of this reference period. A sensitivity analysis could be performed on the background data to assess the robustness of the proposed designs. Alternatively, advanced methods for the collation of representative weather data based on longer periods of time (e.g. 10 years) could be adopted to prevent over-fitting. Moreover, the model is based on the scaling of historical generation profiles with fixed shape. Forecast uncertainty in renewable energy availability is neglected, as well as the impact of climate change on future weather patterns.

The distribution functions used in the uncertainty analysis are fitted on cost and efficiency data collected from the literature. Despite the effort of including only recent studies as well as forecasts to construct an up-to-date collection of background data, the distributions might be over-influenced by late market conditions and thus not fully represent future projections. In particular, wind and solar energy has been experiencing an accelerated cost reduction in the past five years, which is far greater than previously predicted [148]. For this reason, cost and efficiency data could lead to an overestimation of both, the LCOE and the required storage capacity. The inclusion of more peer-reviewed data and future market projections would decrease the energy cost and eventually improve the p-value characteristic of the probability distribution functions. Moreover, to be as close as possible to real conditions and accurately design the energy system, the hourly capacity factors of the generation resources are derived using real-time electricity production data. However, innovations and advancements in the design of generators will possibly lead to increased capacity factors of solar [149] and wind [148]. This effect is not included in the model, hence the resulting installed capacities could be overestimated.

4.4 Electrical synergy in Europe

This work focuses on showing scientific evidence of the potential gains attained by cooperation in reducing emissions and costs in Europe. The results demonstrate that the combined renewable output of all countries is far less volatile than the output of each individual one as a consequence of geographic diversity. Linking solar and wind production across multiple countries reduces the daily and seasonal variability of renewable generation by 40% and 36%, respectively (Tab. C.5.6). Besides generation, the same effect is observed in the demand, for which fluctuations are flattened when profiles are aggregated (Tab. C.5.7). As a result, supply and demand are better matched in the interconnected solution, increasing the share of electricity demand that can be directly supplied by renewable generation, without resorting to storage discharging. Indeed, 81% of demand is covered by direct generation when countries are isolated, a share that grows to 89% when grids are interconnected. Such an effect, together with the 9% decrease in the amount of renewable generation, results in a 14pp increase of the direct supply with 79% of the total produced electricity directly consumed instead of 65%. As a consequence, national grid interconnections serve as an additional benefit to grid stability, providing a way to hedge against sudden shortfalls of renewable supply, which can be frequent in small and isolated systems.

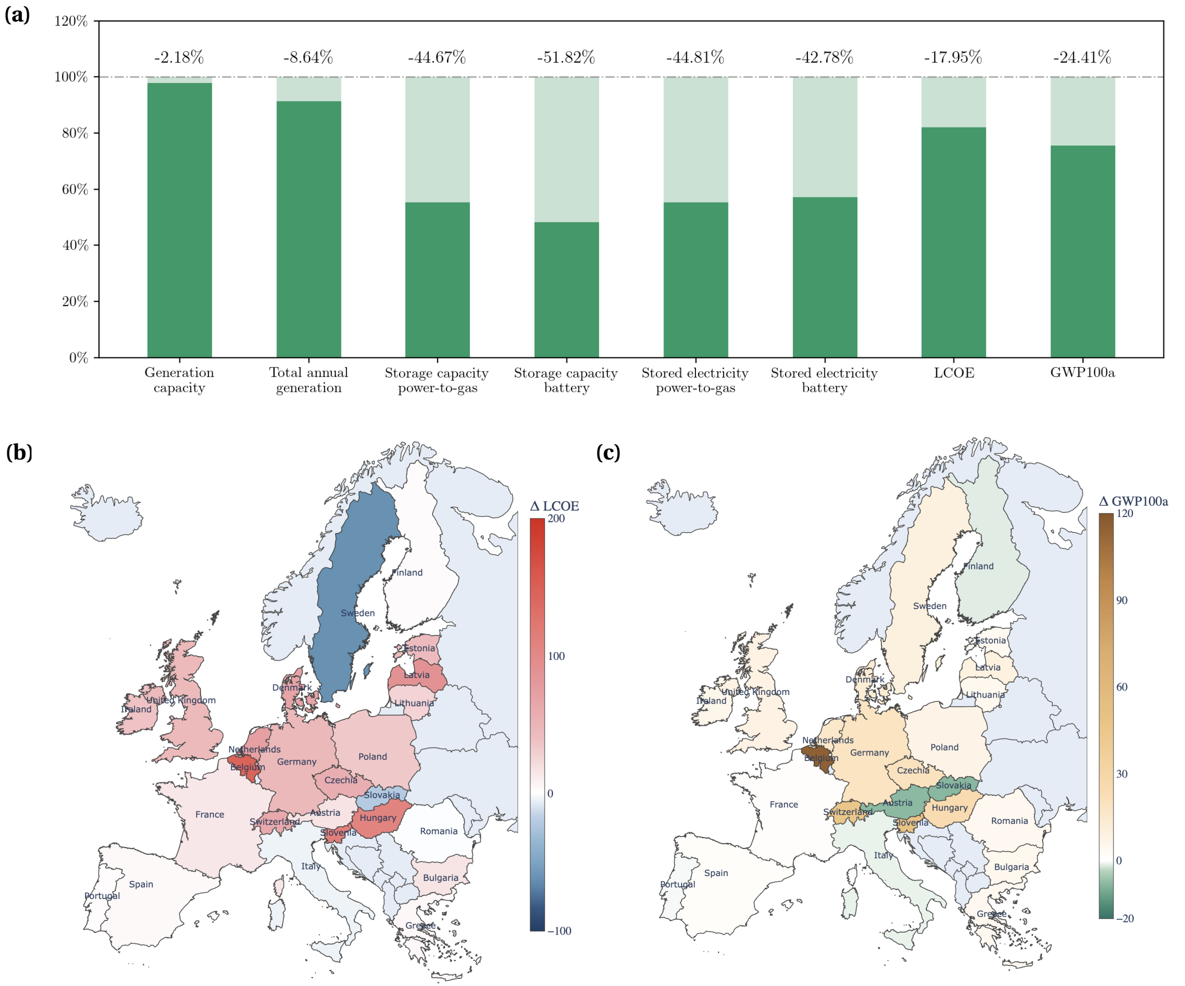

Figure 4.4.1 – Electrical synergy in Europe: **(a)** a comparison between aggregated results of independent countries with isolated grids (baseline at 100%) and a unique European electricity production and storage system with interconnected grids, with improvements shown in terms of relative deviation from the baseline for economical, technical and environmental indicators (Table D.2.1). **(b)** the difference between isolated and interconnected grids LCOE [EUR/MWh] per country – a positive ΔLCOE (red) represents a reduction in electricity price upon interconnecting, and a negative value (blue) corresponds to an increase in electricity cost. **(c)** the difference in the Global Warming Potential (ΔGWP100a) [gCO_2eq/KWh] of the isolated versus interconnected grids, highlighting the countries that would most reduce their carbon emissions (brown) upon joining the European grid. The overall reduction amounts to 54 Mt of avoided equivalent carbon emissions per year. The results of **(b)** and **(c)** are included in Table D.2.2.

Substantially less storage is needed in the synergistic solution compared to independent countries.

Interconnecting national grids reduce the required capacity of long- and short-term storage by 45% and 52% (Tab. D.2.1), respectively, hence decreasing the contribution of the storage build-out to the total cost from 31% to 20% (Tab. C.10.2) and the system LCOE by almost 18%. Like costs, the environmental impact of the fully interconnected scenario is significantly lower than the isolated grids. Cooperation decreases the equivalent carbon emissions associated with the construction and decommissioning of the energy system by 24% (Fig. 4.4.1a) with 36 instead of 48 gCO_2eq emitted per kWh of consumed electricity.

The low-cost, reliable energy system achieved by the interconnected scenario is the result of unequal efforts among countries. Fig. 4.4.1b shows the difference between the LCOE of the isolated and interconnected grids, namely the reduction of the electricity cost achieved by each country upon joining the European grid. As demonstrated, the cost abatement is unevenly distributed among participants, with smaller countries benefiting the most from the joint system. Such an effect is due to the greater overall resource availability of the shared grid, which is otherwise limited in smaller areas. Analogously, the approach can be used to identify the countries that achieve a lower carbon intensity of the consumed electricity, as well as those incurring higher emissions (Fig. 4.4.1c).

Incentivized cooperative scheme for energy security

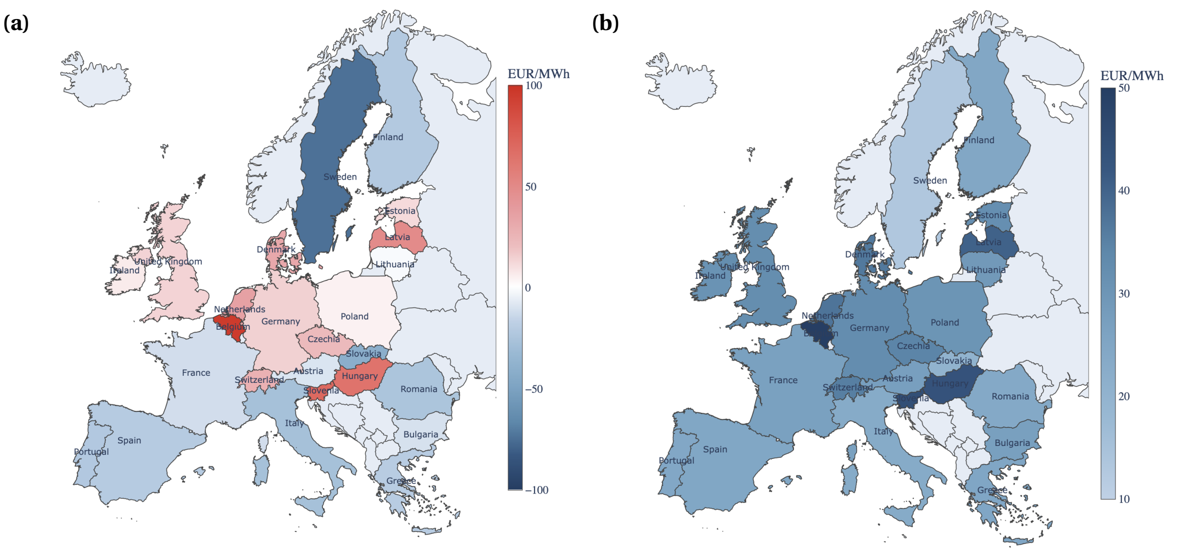

Figure 4.4.2 – Economic value of energy security and monetary benefit of the interconnected scenario over isolated grids. **(a)** price that countries should pay for security of supply (red), or expected compensation (blue) for providing inexpensive renewable electricity (Table 4.4.1). **(b)** monetary benefit obtained by each country participating in the interconnected system. The aggregated cost savings among all countries amount to 130 bn EUR per year.

In addition, comparing the reduced LCOE to the uniform price of the shared network allows determining the economic value of the energy security service. This value represents the price that countries should pay for the security of supply or the expected compensation for granting access to substantial renewable potential. Fig. 4.4.2a demonstrates that small countries surrender much of their energy security to neighbours, while larger countries supply cheap renewable electricity to the grid. Balancing between the reduced electricity price and the provided service for energy security allows for quantification of the monetary benefit obtained by each participant. As shown in Fig. 4.4.2b each country is able to realise an economic gain. As a result, grid interconnection is an economically advantageous solution, which is beneficial for all countries provided that an incentivised cooperative scheme for energy security is established.

Country	Security of supply [EUR/MWh]	Monetary benefit [EUR/MWh]	Annual savings [MEUR/year]
Austria	-9.67	27.50	2582.61
Belgium	95.90	50.60	6343.35
Bulgaria	-10.99	27.21	1300.16
Czechia	22.91	34.63	3488.61
Denmark	31.97	36.61	2007.80
Estonia	11.43	32.12	415.84
Finland	-22.16	24.77	2670.32
France	-12.06	26.98	17551.72
Germany	14.64	32.82	26759.60
Greece	-20.31	25.17	1722.65
Hungary	64.48	43.72	3056.75
Ireland	6.37	31.01	1353.70
Italy	-27.89	23.51	10625.61
Latvia	49.26	40.39	534.09
Lithuania	-1.77	29.23	598.24
Netherlands	35.83	37.46	6198.78
Poland	4.12	30.52	8345.74
Portugal	-22.62	24.67	1588.14
Romania	-25.05	24.14	2120.39
Slovakia	-42.00	20.43	860.93
Slovenia	69.86	44.90	842.61
Spain	-21.07	25.01	8345.26
Sweden	-74.75	13.26	2270.11
Switzerland	27.57	35.65	3081.89
United Kingdom	13.58	32.59	15824.33

Table 4.4.1 – Energy security service and monetary benefit of the interconnected system. The value of the energy security service represents the price that each country should pay for security of supply (positive), or the expected compensation (negative) for providing cheap renewable electricity to the European grid. The monetary benefit is fairly distributed among all participants in such a way that each country realises the same cost reduction (-18%) upon joining the shared network.

4.5 Capacity requirements for electricity storage

Bussar et al. [143] used a genetic optimization framework to assess the future 100% renewable European energy system, relying exclusively on wind and solar generation. An interconnected Europe requires 2.5 TW of renewable generation and approximately 240 TWh of storage capacity to achieve complete self-supply, with a LCOE (excluding distribution) of 69 EUR/MWh. The same group [142] predicted, two years later (2016) and for the same geographic region, an installed generation capacity of 4.5 TW and total storage capacity of 804 TWh. Child et al. [150] contributed to the discussion by using an hourly resolved model. Storage requirements add up to 222 TWh, with 3.3 TWh for batteries and 218 for P2G (SNG). LCOE achieves 51 EUR/MWh (compared with the current 69 EUR/MWh) and storage account for 31% of the total LCOE (16 EUR/MWh). Pierro et al. [144] achieved 92% of RE penetration with PV and wind generation capacity of 130 and 50 GW, respectively, coupled with 120 GWh of battery storage. Other studies [32, 151] show a considerable cost increase for an exclusive RE system with storage, triggering the use of low-CO_2 dispatchable technologies.

Uncertainty analysis of the Pareto-efficient solutions

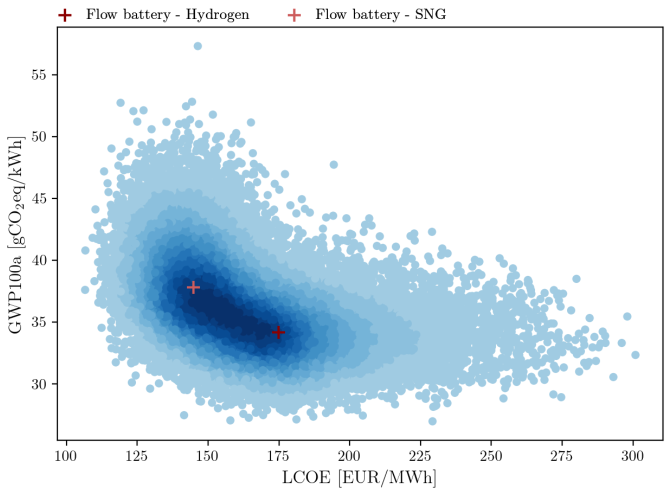

Figure 4.5.1 – Uncertainty analysis of the Pareto-efficient solutions for interconnected grids, showing the probability density plot, which is obtained applying the 2-σ Kernel Density Estimation (KDE) with Gaussian shape to the euclidean distance (LCOE-GWP100a domain) between the simulated solutions. The means of the probability functions are identified by the crosses for each type of power-to-gas storage with flow battery. The selected combinations are the Pareto-efficient ones prior to the uncertainty analysis (Table D.3.1).

Uncertainty analysis is performed by exploring changes in the Pareto-efficient solutions to assess the effect of uncertain parameters on the design and performance of the system. Fig. 4.5.1 shows how the Pareto frontier transforms from a collection of deterministic results into a probabilistic distribution of solutions. The means of the probability functions are highlighted in the plot for each combination of storage technologies that is found on the Pareto front of the interconnected scenario. The only solutions located on the front implement flow batteries, whereas both SNG and Hydrogen technologies are interesting options for P2G.

Comparison of storage technologies

Overall, the selection of long-term storage technology has the highest impact on the system performance in terms of both cost and emissions. Hydrogen is to be preferred over SNG if the environmental impact represents the main concern (11% fewer emissions compared to SNG), whilst SNG allows for system costs that are 17% lower relative to hydrogen (Tab. D.4.1). This is confirmed in Fig. 4.5.2, where 85% of the solutions below 35 gCO_2eq/kWh install hydrogen, a share that grows up to 98% for a maximum allowed impact of 30 gCO_2eq/kWh (Tab. D.3.3). Conversely, only scenarios with SNG are found for a maximum LCOE of 127 EUR/MWh and more than 95% of solutions install SNG for an LCOE lower than 150 EUR/MWh (Fig. D.3.1). Conversely to P2G, the choice of flow battery technology is far less significant in terms of costs and emissions. Zinc flow batteries are associated with 3.6% higher cost than vanadium flow, whereas they reduce carbon emissions by 3.4% (Tab. D.4.2). As a result, the choice of battery technology within the flow category leads to minor changes on the system performance, which are almost negligible compared to the selection of the P2G storage.

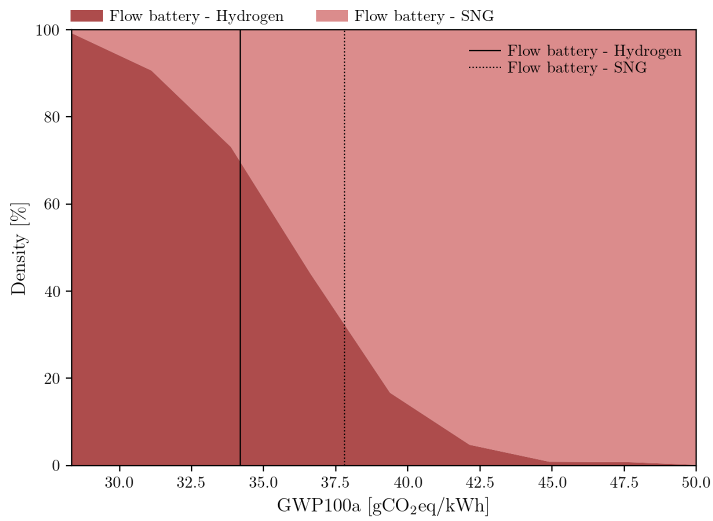

Figure 4.5.2 – Solution density [%] of each storage system design as a function of the Global Warming Potential (GWP100a) [gCO_2eq/kWh] (Table D.3.3). The vertical lines are the median values of the distributions.

Capacity distributions by country

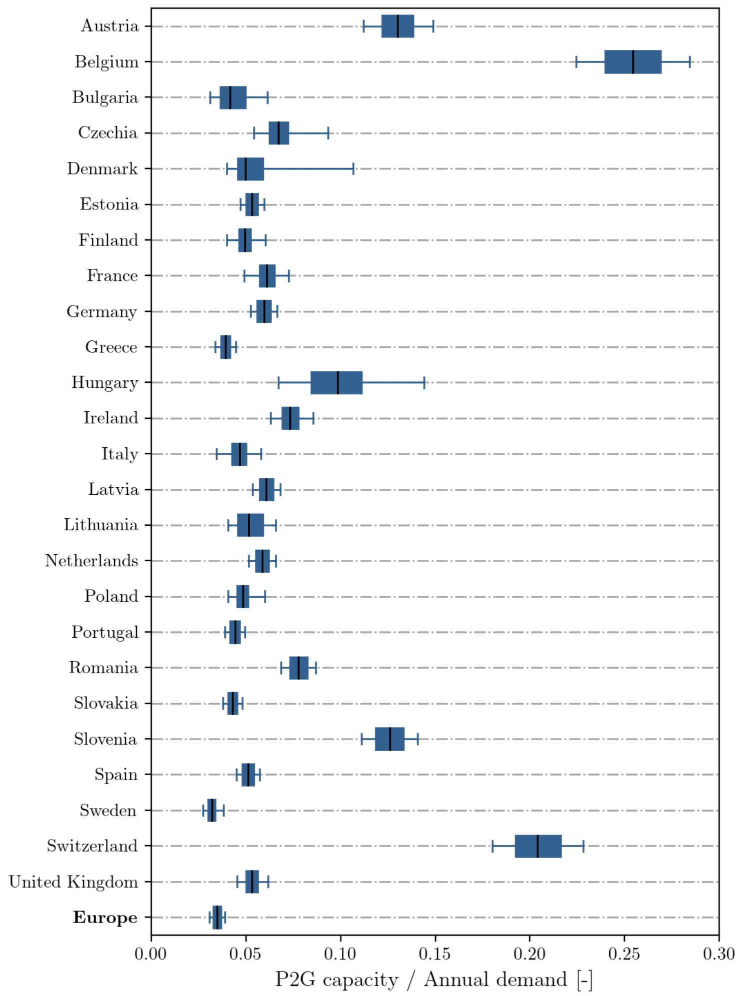

Figure 4.5.3 – Storage capacity distributions of P2G calculated as share [-] of the annual electricity demand (Table D.4.3). The boxes identify the Interquartile Range (IQR = Q3 - Q1), while the lower and upper whiskers correspond to the minimum and maximum observed capacities.

Fig. 4.5.3 shows the uncertainty range of the P2G capacity that is installed by each country and for an interconnected Europe. The capacities are calculated as the share of the annual electricity demand, providing a way to scale storage with respect to the projected consumption. As illustrated in the figure, the medians of the capacity distributions vary between a minimum of 3.2% for Sweden (5.5 TWh), where the stable supply from hydro dams allows for a low storage need, and a maximum of 25% for Belgium (31 TWh) because of the strong seasonal cycle in solar generation. In absolute terms, Germany installs the highest capacity (49 TWh), followed by France (40 TWh) and the United Kingdom (26 TWh). The lowest P2G size is found in the Baltic countries, where Latvia and Lithuania require as little as 0.8 and 1.1 TWh of long-term storage, respectively. Overall, the aggregated capacity of the independent countries with isolated grids reveals the need for a massive European P2G installation of 288 TWh, a size that can be reduced to 154 TWh by interconnecting the grids.

Similarly to P2G, the required capacity of short-term storage through batteries is directly correlated to PV installation. The inter-hour variability of electricity output from solar panels leads to the substantial requirements for battery capacity, which is highest in Belgium (0.27% of demand, 0.33 TWh) and Hungary (0.20% of demand, 0.14 TWh). Significant installations relative to demand are also found in Latvia (0.03 TWh), the Netherlands (0.27 TWh) and Denmark (0.08 TWh), with batteries mainly used to smooth wind power output (Fig. 4.5.4). The total capacity of all countries amounts to 4.36 TWh if grids are isolated and to 2.14 TWh in the case of an interconnected Europe.

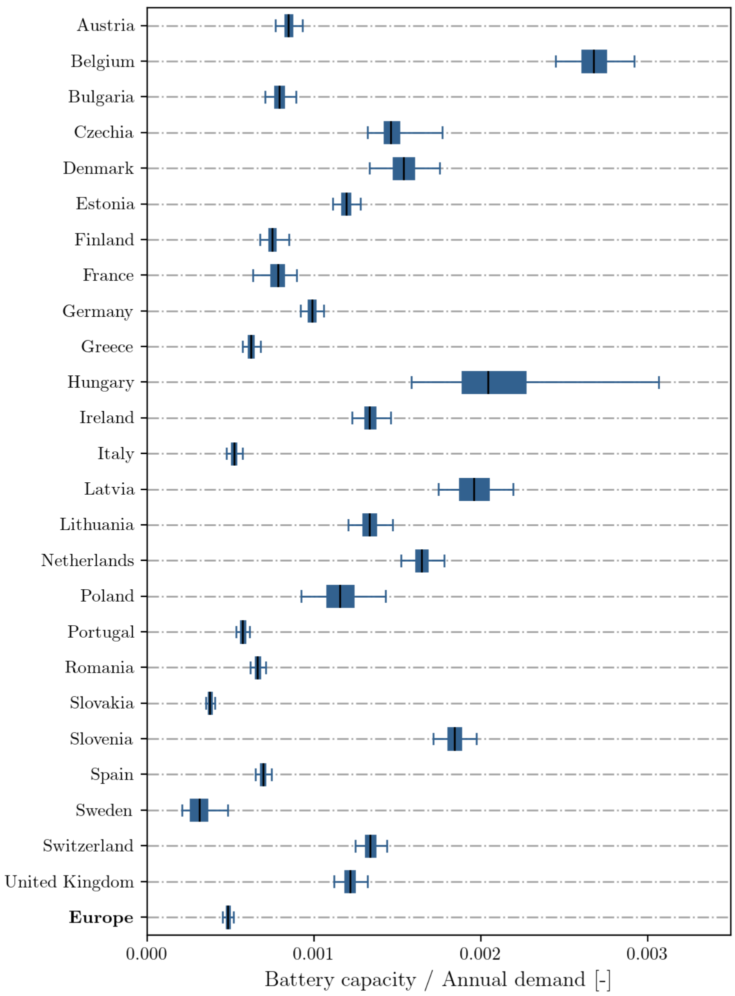

Figure 4.5.4 – Storage capacity distributions of battery calculated as share [-] of the annual electricity demand (Table D.4.4). The boxes identify the Interquartile Range (IQR = Q3 - Q1), while the lower and upper whiskers correspond to the minimum and maximum observed capacities.

Estimation of capacity contribution for grid adequacy

A zero-carbon constrained system faces obvious difficulties in maintaining reliability of supply. Extreme conditions such as steep load ramps, peak and minimum demands, and severe weather events cause demand-supply imbalances, which endanger the stability of the grid. Although the capacity contribution of storage is finite, the ability of batteries and P2G to deal with extremes becomes crucially important for reliable operation. Storage must ensure resource adequacy by resisting sustained loss of generation, which can be frequent in a 100% renewable power system. Large amounts of stored energy must be released on-demand to provide a stable supply, even when no other sources of electricity are available.

The presented methodology takes into account system reliability needs by deriving the required storage size from the simulated operations. The battery and P2G systems are indeed designed to withstand peak demand and renewable generation shortages which are reproduced using realistic electricity generation and demand data. The results show that fully charged batteries are able to maintain electricity supply for a maximum duration of 7 hours under average power demand conditions with isolated grids. Such capacity contribution reduces to 4 hours when grids are interconnected due to the substantially lower installed capacity. However, when considering the peak discharge power, a comparable capacity contribution is observed in the two scenarios: 9 hours for the isolated grids and 8 hours for the interconnected system (Table D.4.5). This effect is due to the significantly lower severity of power shortfalls, which decrease by 49% in the synergistic Europe. As a result, interconnections serve as a safety measure against extreme conditions, reducing power shortfalls and contributing to grid reliability during long energy deficit periods.

4.6 Effect of curtailments on the energy system

Curtailing RE generation - perceived as ’green’ and with close-to-zero marginal cost - is oftentimes regarded by the public as unacceptable. This view can lead to storage oversizing and reduced investment in generation technologies. Ideally, and based on a pure mathematical reasoning, the level of curtailment should go up until the shadow price of curtailment equals that of the discarded energy. Jacobsen and Schröder [152] recognised the difficulty in achieving a high share of RE without curtailment and predicted that countries with higher exposure to offshore wind are likely to have higher shares of curtailment. In a recent publication [153], the National Renewable Energy Laboratory (NREL) explored the curtailment paradox in the transition to high-renewable energy systems. Although the study focused exclusively on solar power systems, it reveals the importance of both curtailment and storage in promoting high RE penetration. In fact, and contingent to assumptions therein, no more than 30% of solar PV penetration could be achieved without storage.

RE curtailment, when used adequately, can reduce the LCOE by promoting a reduction in storage capacity requirements: Solomon et al. [154] analysed the curtailment-storage-generation nexus in the energy transition applied to Israel. LCOE with curtailment was found to be 8.6% lower compared to a scenario without curtailment. Without curtailment the value of RE penetration reaches only 70% of the annual demand, while reaching 90% if curtailment is allowed, removing the early need for large long-term storage options. Pierro et al. [144] contributed to show how active curtailment is paramount to reduce the investment needed in high renewable share systems. Using Italy as a case study, increasing levels of curtailment (up to 23%) enabled decreases in the LCOE compared with a non-curtailment situation which achieves prohibitive LCOES values - and reaching 41 EUR/MWh by 2060.

Barnhart et al. [155] focused on comparing the energy efficiency of storing electricity versus curtailing generation, quantifying conditions for curtailment deployment. According to the presented results, PV generation coupled with any storage system yields higher energy investment than curtailing. For wind with battery storage options the energy investment must exceed 80, which is the ratio between the electrical energy stored over the battery lifetime and the energy embodied to build the technology. This is achievable by extending the lifetime by 2 to 20 times the current values.

As generation costs continue to decrease due to increasing mass production, storage costs need to follow. Otherwise, it will be cheaper to increase generation and disregard storage technologies, thus promoting curtailment and partially abdicating control over charging and discharging steps. Indeed, Clerjon et Perdu [23] recognise the benefit of curtailing excess electricity, avoiding storage oversize and thus entailing lower investment. Arbabzadeh et al. [30] reached a similar conclusion, by recognising that RE curtailment is ultimately a decision based on the investment needed to activate storage options.

Curtailed power and storage operating profiles

The effect of curtailments on the system performance and design is investigated by simulating different curtailing strategies in the isolated grids and synergistic scenario with expanded transmission. This is achieved by a modified version of the algorithm, which curtails the excess wind and solar generation to reduce the useful energy. An example run is given in Fig. 4.6.1a and 4.6.1b, which shows the daily and hourly curtailed excess and deficit power profile for the interconnected grids. As expected, diurnal and inter-hour power fluctuations decrease in number and intensity compared to baseline (no curtailments), with energy surplus periods having longer duration due to the overbuilt generation. Load ramps are far less intense when curtailments are used, leading to smoother charges and discharges of the storage during the year.

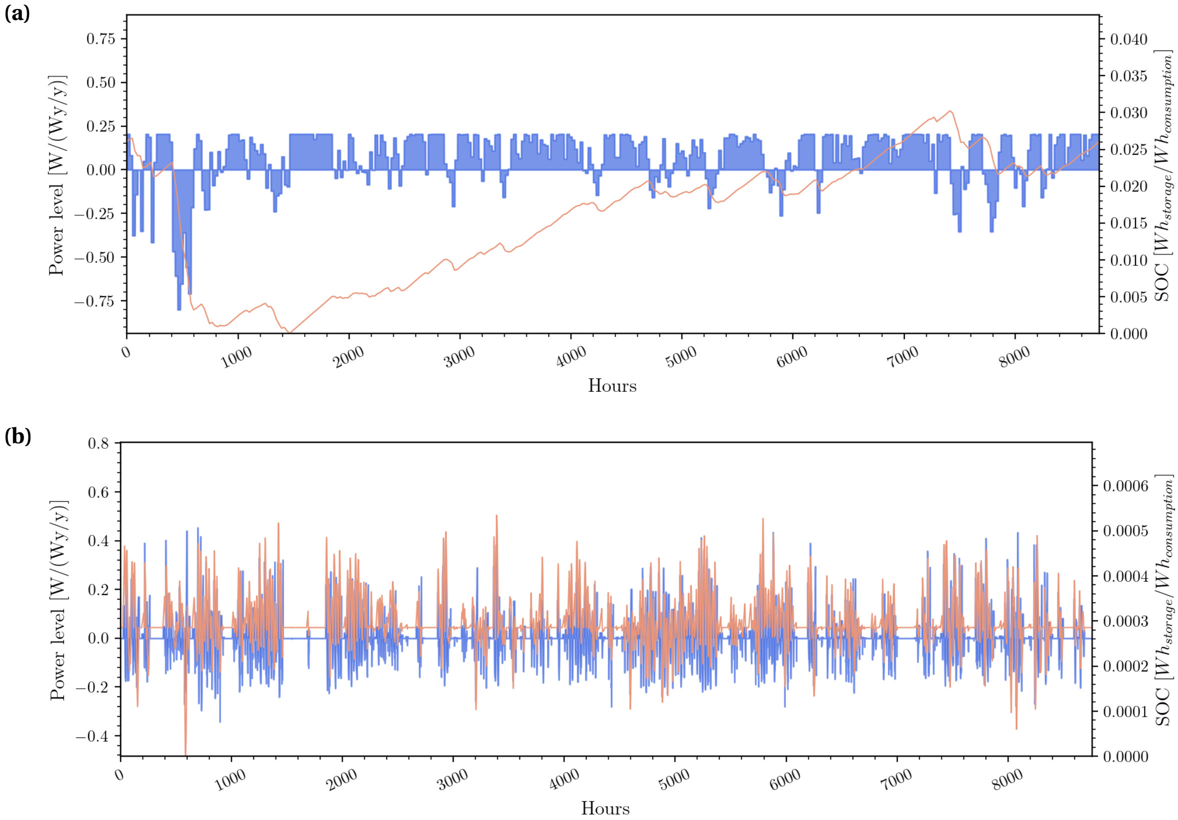

Figure 4.6.1 – Hourly long- **(a)** and short-term **(b)** storage profiles for all Europe. Results obtained starting from the solution of Figure 3.6.1 with curtailment factor of 0.85. **(a)** power level and State of Charge (SOC) of the SNG storage with total capacity of 119 TWh – 26% decrease from the corresponding solution without curtailment (Figure 3.6.5) **(b)** vanadium flow battery with total capacity of 1.8 TWh (-10%). The generation mix is oversized by 10% (5,466 TWh of production) to balance the curtailed electricity.

Effect of curtailment on LCOE and GWP100a

Fig. 4.6.2 shows how curtailment contributes to reducing system cost in an interconnected Europe. As displayed, the LCOE decreases as a function of the curtailment factor, which allows to gradually reduce the need for expensive storage. A sharp rise in cost occurs for curtailments higher than 20% - 30% of the combined solar and wind output. Such sudden change in the LCOE trend is caused by the massive over-building of generation capacity (Fig. 4.6.3), the cost of which offsets and eventually overruns the savings from reduced storage (Fig. 4.6.4). As a result, the adoption of grid operating strategies based on moderate curtailments (10% - 20%) can benefit energy cost. More specifically, the expanded system achieves up to 18% reduction in the LCOE by allowing 16% curtailment of solar and wind resources. Similar results are obtained for the isolated grids (Tab. D.5.4), with countries able to decrease the LCOE by 22% (improvements ranging between 15% and

30%) with approximately 30% curtailments (20% - 40%).

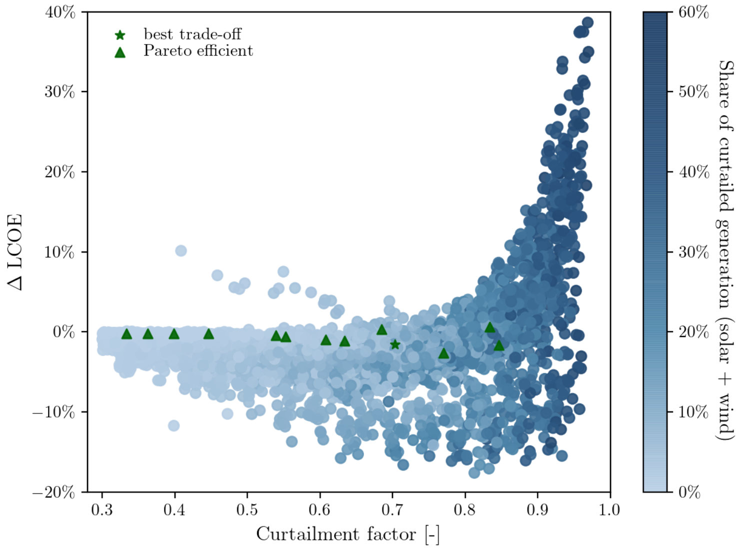

Figure 4.6.2 – Effect of curtailments on system LCOE. Percentage reduction in the energy cost (ΔLCOE) of the curtailed solution from the baseline (no curtailments). Data points coloured with respect to the share of curtailed solar and wind generation.

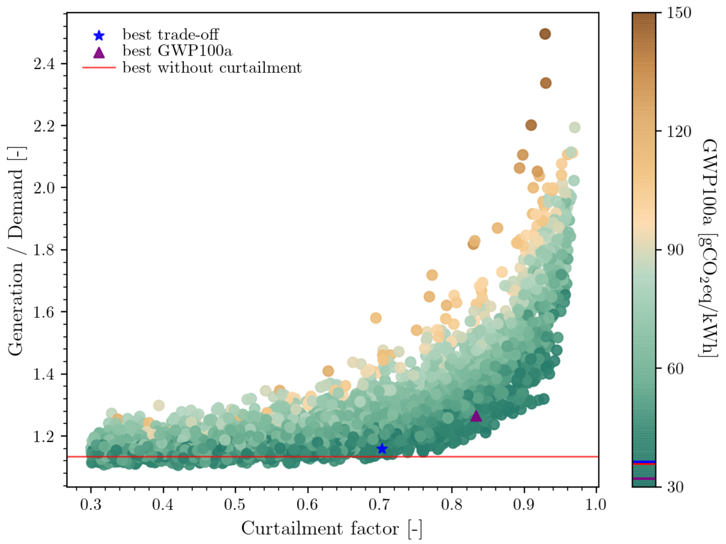

Figure 4.6.3 – Effect of curtailments on generation capacity. The required generation increases as a function of the curtailment factor. The simulation points are coloured with respect to the associated Global Warming Potential (GWP100a) in grams of CO_2 equivalent per kWh of consumed electricity. The red solid line corresponds to the optimal solution without curtailment. The star and triangle markers shows the best LCOE/GWP100a trade-off point (Table D.5.1) and the cleanest scenario (Table D.5.2), respectively.

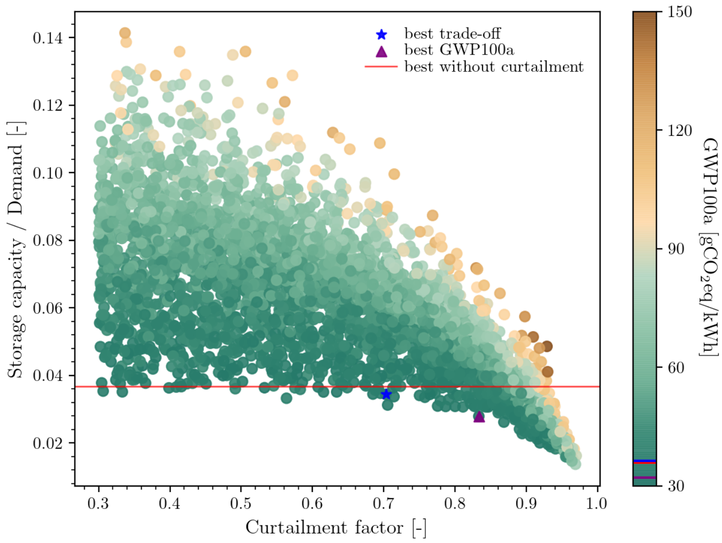

Figure 4.6.4 – Effect of curtailments on storage capacity. The storage capacity decreases as a function of the curtailment factor. The star point locates the best LCOE/GWP100a trade-off point among all the curtailed solutions. The triangles refer to the Pareto-efficient solutions.

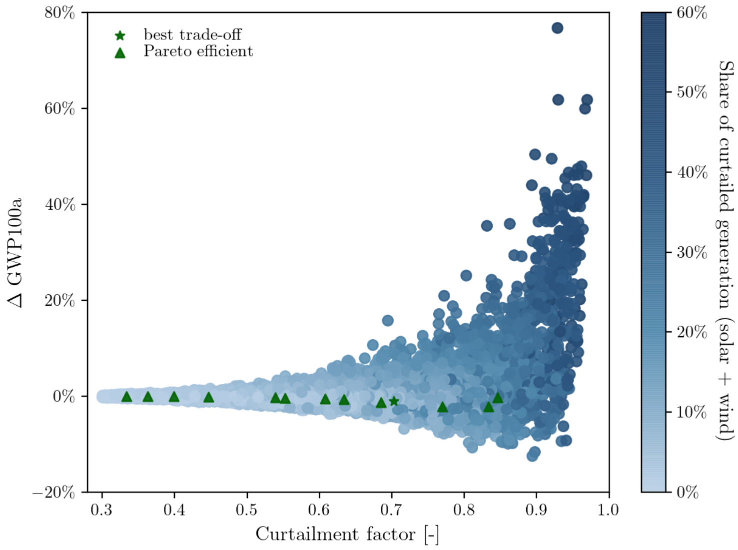

Figure 4.6.5 – Effect of curtailments on system GWP100a. Percentage in climate change (ΔGWP100a) of the curtailed solution from the baseline (no curtailments).

Besides cost, the global warming potential associated with the system can also benefit from curtailing excess energy. Fig. 4.6.5 shows that the interconnected Europe decreases its emissions by 13% by allowing for 25% curtailments. Independent grids achieve climate change improvements ranging from 0%, in countries where solar is the only available option for capacity addition (Belgium, Slovenia and Switzerland), to 15-20% (Tab. D.5.5), where over-building wind resources allows replacement of storage with clean generation (France, United Kingdom, Ireland). As a result, given the current environmental impacts associated with solar and wind-based generation, curtailments are found to mostly reduce emissions in countries with high wind potential and capacity factor (>0.25). Moreover, transmission expansion allows for a more efficient use of renewable resources, increasing system flexibility and mitigating curtailments.

When considering the Pareto efficient solutions, the benefits from curtailing excess electricity are limited. Almost no improvement (<2%) was observed for this set of solutions, indicating that curtailments become less attractive if the energy system is optimally designed. As a consequence, curtailments represent a cost-effective option in sub-optimal scenarios, characterised by poor technology choices (i.e. low capacity factors, high variability, strong seasonal cycle) with excessive over-sizing of generation and storage.

While curtailments can improve costs and emissions, the risk of incurring economic losses and higher impact also increases with the intensity of the power reduction strategy. This is demonstrated by the growing range of possible solutions, with unfavourable scenarios increasing in number when more severe curtailments are considered. As reported in the Tables D.5.4 and D.5.5, such risk varies between countries, and it is not affected by system expansion. Consequently, particular care must be taken whenever designing grid operating strategies based on curtailments of power. As demonstrated in this work, a strategy that reduces costs for a certain system can turn out deleterious to a different one (i.e. different grid composition) if systematically applied. Simulation-based methodologies which allow one to consistently explore the possible solution space are essential for the design of risk-aware strategies, whose efficacy changes with the evolution of the energy system.

4.7 Decarbonization of the electricity grid

Figs. 4.7.1a and 4.7.1b show the impact associated with the generation and storage of electricity when grids are isolated. As displayed, the carbon emissions associated with generation capacity dominate in Sweden (>80%), Bulgaria, Romania and Slovenia (>60%), while storage achieves the highest impact share in Ireland (67%) and Hungary (66%). Overall, the country-weighted carbon emissions are equally distributed between generation and storage in the case of isolated grids, while the environmental impact of storage decreases by more than 45% when grids are interconnected – from 23.34 to 12.61 gCO_2eq/kWh (Tab. D.6.1). As demonstrated in the synergistic analysis, the greatest benefit obtained by expanded transmission is the reduced need for storage, which consequently represents the main element for driving emissions lower.

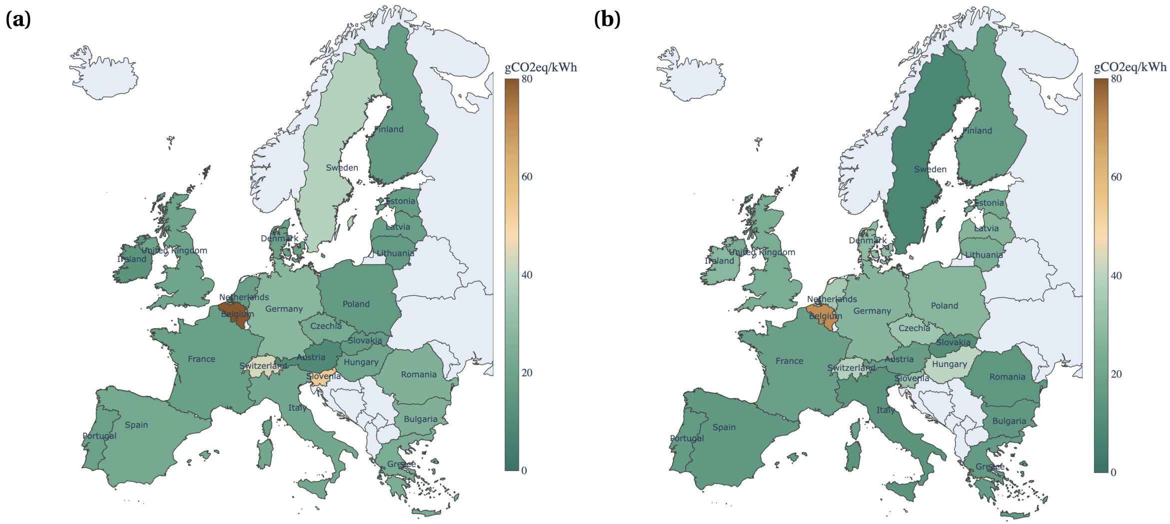

Figure 4.7.1 – Climate change of the energy system associated with the best observed solutions of the isolated grids. Global Worming Potential (GWP100a) in grams of CO_2 equivalent emitted per kWh of consumed electricity (Table D.6.1). **(a)**, impact associated with the generation mix and **(b)** storage system.

Although the construction of a 100% renewable European grid requires massive investments, it comes with great environmental benefits. As shown in Fig. 4.7.2, the isolated grids achieve a reduction in the GWP100a comprised between 30% to 95%, with the highest improvement obtained in Poland, where the current mix is mostly fossil-based, and the lowest in Belgium, where overbuilt solar partially offsets the benefits of phasing out fossil reliance. Relatively small improvements are observed in France (-49%) and Switzerland (-53%) due to their current low-carbon energy systems – at present France owns the largest nuclear fleet in Europe and Switzerland mostly relies on clean hydro resources (Tab. C.4.2).

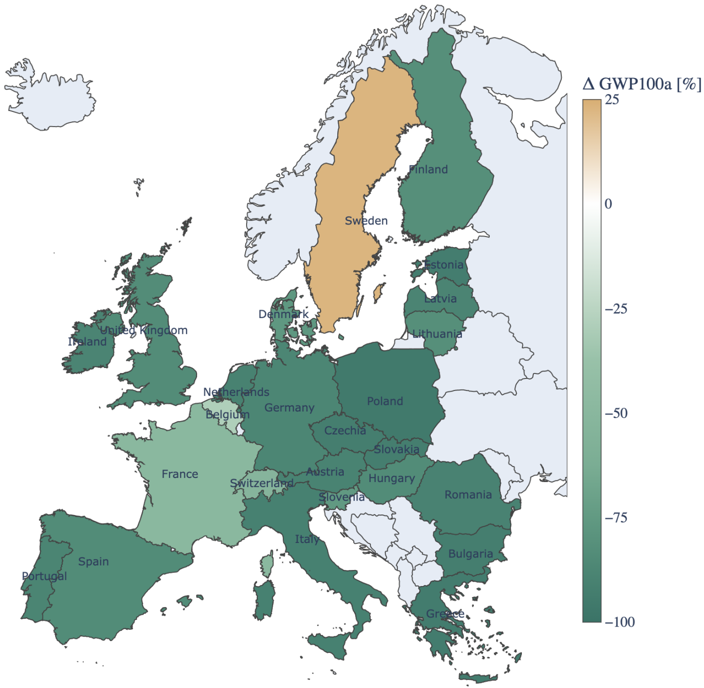

Figure 4.7.2 – Environmental benefit of the 100% renewable energy system. Results of the best observed simulations *without curtailment*. Relative deviation in Global Warming Potential (GWP100a) of the simulated countries from their current grid intensities (Table 4.7.1).

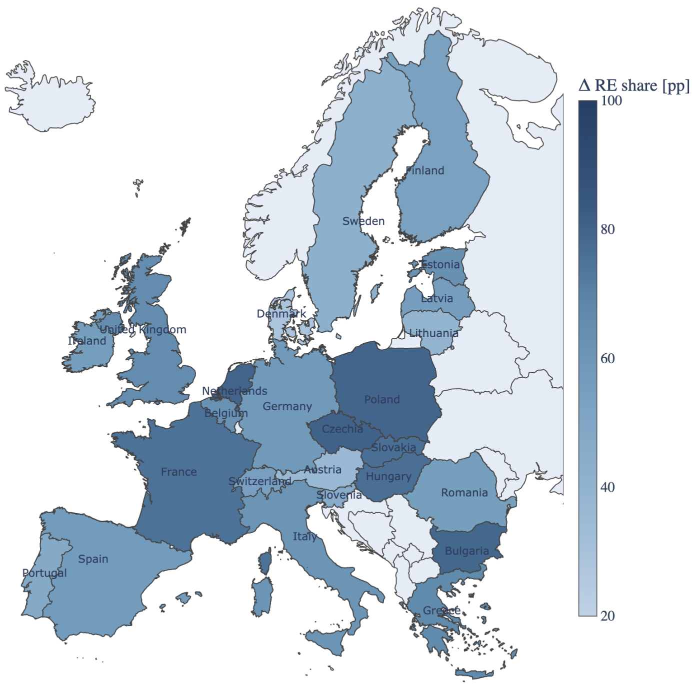

Figure 4.7.3 – RE share increase in point percentage [pp] by country.

Moreover, it must be noted that the construction of a 100% renewable system leads to higher emissions in Sweden (+23%). This is due to a national generation mix that is currently based on renewable resources (54% RE share) and nuclear. However, when considering other environmental indicators, significant improvements can be achieved in Sweden. As displayed in Fig. 4.7.3, the renewable share of the country increases by 43 pp when nuclear is replaced by additions of hydro and wind capacity. Like RE share, the ecological footprint and ecological scarcity indicators, namely the system demand on natural capital and its impact on biodiversity, improve by 90% and 71%, respectively (Fig. D.6.1a and D.6.1b).

	RE share [-]		IPCC 2013 climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
Country	**Method 1** [1]	**Method 2** [2]	**GWP100a**	**GWP20a**	**Total**	**Total**
Austria	1.00 (+31pp)	0.97 (+36pp)	27.92 (-90%)	14.48 (-95%)	41.78 (-82%)	0.037 (-96%)
Belgium	1.00 (+81pp)	0.80 (+63pp)	152.16 (-29%)	141.61 (-40%)	306.60 (-2%)	0.353 (-82%)
Bulgaria	1.00 (+84pp)	0.93 (+79pp)	40.94 (-93%)	34.64 (-94%)	78.39 (-87%)	0.081 (-97%)
Czechia	1.00 (+84pp)	0.93 (+81pp)	55.66 (-93%)	36.13 (-96%)	78.82 (-88%)	0.085 (-97%)
Denmark	1.00 (+29pp)	0.94 (+28pp)	49.12 (-76%)	29.86 (-87%)	71.49 (-68%)	0.069 (-94%)
Estonia	1.00 (+68pp)	0.94 (+64pp)	40.24 (-93%)	26.20 (-96%)	60.01 (-90%)	0.061 (-97%)
Finland	1.00 (+58pp)	0.95 (+54pp)	34.49 (-82%)	24.28 (-89%)	66.19 (-77%)	0.056 (-97%)
France	1.00 (+79pp)	0.95 (+76pp)	37.19 (-49%)	26.25 (-67%)	60.47 (-81%)	0.063 (-97%)
Germany	1.00 (+56pp)	0.92 (+59pp)	54.86 (-88%)	41.70 (-92%)	92.10 (-75%)	0.101 (-93%)
Greece	1.00 (+70pp)	0.94 (+67pp)	40.32 (-94%)	33.18 (-96%)	69.98 (-88%)	0.079 (-96%)
Hungary	1.00 (+81pp)	0.94 (+77pp)	61.02 (-84%)	35.27 (-92%)	78.68 (-82%)	0.083 (-96%)
Ireland	1.00 (+58pp)	0.96 (+56pp)	41.88 (-89%)	21.64 (-95%)	51.27 (-84%)	0.051 (-95%)
Italy	1.00 (+63pp)	0.94 (+62pp)	34.91 (-91%)	28.95 (-93%)	66.56 (-78%)	0.075 (-94%)
Latvia	1.00 (+58pp)	0.94 (+56pp)	45.50 (-89%)	28.70 (-94%)	65.66 (-82%)	0.068 (-95%)
Lithuania	1.00 (+39pp)	0.95 (+40pp)	40.72 (-82%)	25.02 (-90%)	58.33 (-78%)	0.058 (-95%)
Netherlands	1.00 (+84pp)	0.95 (+80pp)	52.74 (-90%)	29.56 (-95%)	67.13 (-82%)	0.067 (-96%)
Poland	1.00 (+84pp)	0.95 (+80pp)	43.33 (-95%)	24.77 (-98%)	55.89 (-93%)	0.058 (-98%)
Portugal	1.00 (+47pp)	0.95 (+48pp)	35.48 (-88%)	26.66 (-92%)	51.71 (-80%)	0.065 (-94%)
Romania	1.00 (+60pp)	0.94 (+56pp)	40.57 (-90%)	34.90 (-92%)	72.87 (-91%)	0.083 (-95%)
Slovakia	1.00 (+79pp)	0.96 (+77pp)	27.63 (-93%)	22.19 (-95%)	49.99 (-90%)	0.053 (-98%)
Slovenia	1.00 (+57pp)	0.86 (+46pp)	84.81 (-76%)	79.86 (-78%)	176.05 (-61%)	0.189 (-89%)
Spain	1.00 (+60pp)	0.95 (+57pp)	37.48 (-84%)	30.27 (-88%)	58.73 (-78%)	0.075 (-94%)
Sweden	1.00 (+45pp)	0.97 (+43pp)	45.98 (23%)	50.03 (14%)	51.81 (-71%)	0.123 (-91%)
Switzerland	1.00 (+55pp)	0.89 (+55pp)	82.01 (-53%)	68.65 (-65%)	155.86 (-50%)	0.163 (-91%)
United Kingdom	1.00 (+70pp)	0.94 (+66pp)	44.55 (-84%)	30.56 (-89%)	68.96 (-77%)	0.078 (-95%)
Europe *	1.00 (+66pp)	0.94 (+65pp)	35.94 (-89%)	31.41 (-92%)	66.43 (-82%)	0.075 (-96%)

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

* Interconnected grids.

Table 4.7.1 – Environmental impact indicators of the isolated grids and interconnected system (Europe). Results for the best observed simulations. The relative deviations from the indicators of the current grids (Table C.4.2) are included between brackets. The deviation in the renewable share (RE share), namely the increase of the renewable penetration, is given in percentage point (pp).

When the electrification of demand is considered, great improvements are achieved by each individual country with respect to current state. The results demonstrate that green house gas emissions per capita (Fig. 4.7.4) and GDP intensity (Fig. D.6.4) decrease on average by 80%. Such an improvement corresponds to 2,000 Mt of avoided CO_2 emissions each year, or approximately 5% of the annual global carbon emissions. Improvements are more substantial when grids are interconnected: 85% instead of 80%. The renewable share (method 2) increases by 65 pp, passing from the current value of 29% to 94%. Moreover, the ecological footprint of the grid decreases by 96%, which corresponds to a reduction in required natural capital of more than 50% of the European land area.

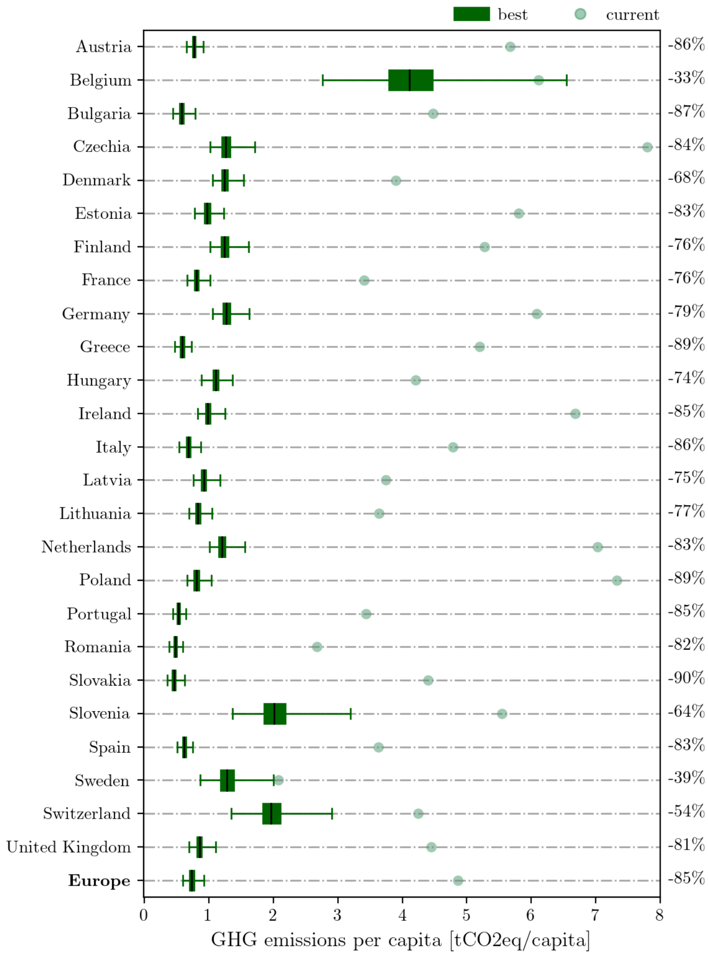

Figure 4.7.4 – Annual Green House Gas (GHG) emissions per capita [tCO_2eq/capita] of the current and 100% renewable grid (Table D.6.5). The relative reduction in the GHG is displayed on the right side of the chart.

The cost of transitioning from the current European energy system to a 100% renewable interconnected one over the next 20 years is estimated to equal 7 trillion EUR. This cost accounts for all the investments required to replace nuclear and fossil based generators with an unprecedented build-out of renewable capacity and storage. Costs associated with maintaining the new power facilities are included in the estimate and discounted over their lifetime. The Equivalent Annual Cost (EAC) of the system amounts to 4.2% of the European Gross Domestic Product (GDP) when grids are interconnected and to an overage of 5% for the isolated scenario (Fig. 4.7.5). Moreover, such a transition would require uneven economic effort among countries if pursued independently, with Bulgaria expected to dedicate almost 15% of its GDP to the energy system while Switzerland only 3%. According to European statistics [156], the actual government expenditure (2019 values) with Fuel and Energy - used as proxy to estimate the expenditure with the energy system - is on average 0.3% of GDP and it ranges from virtually 0% in Austria and Greece to 1.8% in Bulgaria. As a result, Europe should increase investments in energy infrastructures, in particular interconnections, storage and clean capacity, by almost 15 times to accelerate the transition into a low carbon and climate-resilient economy.

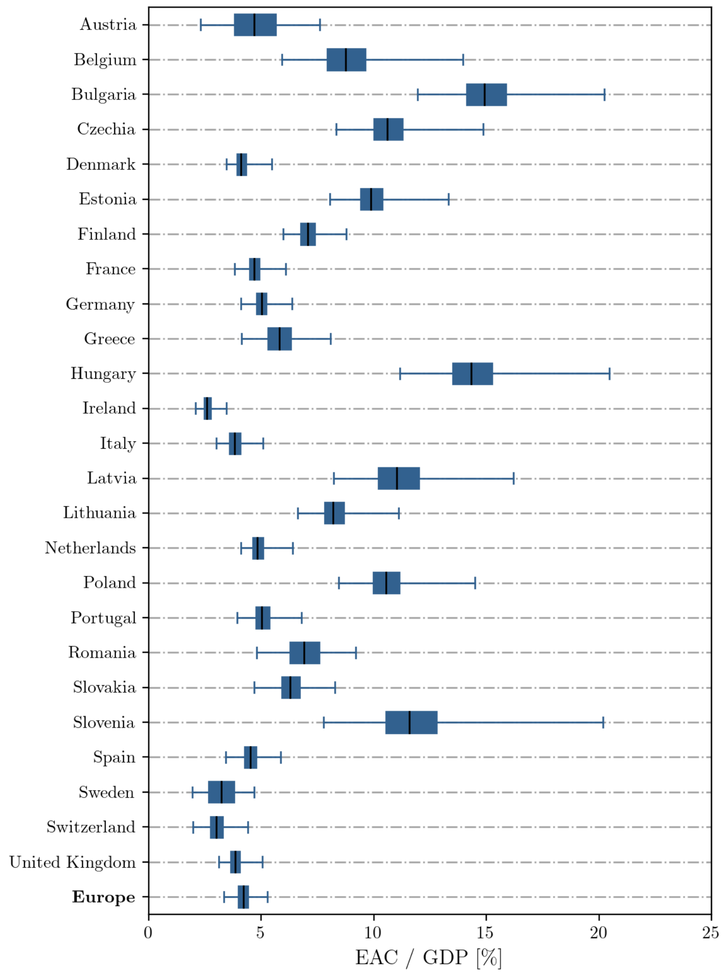

Figure 4.7.5 – Equivalent Annual Cost (EAC) as percentage of the Gross Domestic Product (GDP) by country (Table D.6.7).

4.8 Discussion

The work presented here expands that of Chapter 3, giving focus to grid interconnections and highlighting the benefits of electrical synergies. An hourly resolution is used and an uncertainty framework embedded, seeking robustness in the solutions proposed. A fully interconnected design of the future European power grid is presented and compared to an alternative design based on isolated grids. As demonstrated, both individual and cooperative grid solutions require unprecedented deployment of renewable generation and storage. In particular, storage will play a crucial role to ensure grid adequacy, which is a challenge in a 100% renewable system.

The capacity contribution of storage is quantified by calculating the duration of discharge under sustained peaking conditions. Assuming the maximum discharge peak that is observed in the expanded transmission scenario, a discharge time of 8 hours for battery and 9 days for power-to-gas is estimated. However, it must be noted that grid reliability requirements are not the focus of this work and that the inclusion of stronger reliability measures would likely lead to additions in storage capacity.

All solutions modelled here are generated using a quantitative approach: more than 110,000 simulations are collected, including solutions with curtailments (additional 5 million data points for the uncertainty analysis). Although such an approach is computationally intensive, it allows consistent exploration of the solution space, revealing correlations that alternative methods, such as optimisation-based techniques, might overlook (i.e. complementary patterns of wind and solar, the effect of curtailments on sub-optimal scenarios). On the other hand, optimisation approaches (i.e. MILP formulation) could improve costs and emissions in the interconnected scenario by achieving optimal allocation of generation capacities. However, globally optimal designs would lead to a more unequal effort among countries, increasing energy dependency on neighbours and, consequently, affecting the incentivised cooperative scheme for energy security.

4.9 Conclusions

Electrical synergy results are consistent with findings from previous studies [20, 21, 138, 140, 146, 157]. The interconnected scenario reduces the cost (-18%) and carbon footprint (-24%) associated with electricity as a result of decreased storage and generation requirements. This effect is due to smoother energy output from geographically dispersed renewable technologies, rather than smaller isolated systems that are dependant on local intermittent resources. In addition, grid expansion improves load ramps by taking advantage of complementary demand patterns, which lead to a lower need for peaking capability. As a result, interconnecting the grids is a cost-effective enabler of grid decarbonization, allowing the construction of a more resource-efficient energy system by exploiting synergies between networks.

Although reducing costs, the cooperative scenario entails asymmetric distribution of economic efforts, with smaller countries benefiting the most from the joint system. A novel approach to estimate the economic value of energy security is introduced based on fair sharing of gains. This method quantifies the price a country should be required to pay for security of supply or the entitled compensation for releasing inexpensive renewable energy. As a result, effective policies should be established to encourage cooperation in the European power sector and avoid missing the significant potential of grid interconnections.

Solar and wind curtailment effect on the energy system is simulated under different power reduction strategies. The results demonstrate that the adoption of grid operating schemes based on moderate curtailments (between 10% and 20%) in the cooperative scenario and more severe ones (up to 40%) when countries are considered independently can decrease both costs and emissions. Moreover, the benefits of curtailment on climate change are more significant in countries with substantial wind potential. Ultimately, although curtailments can improve system performance, they become less attractive if the energy system is optimally designed. The best-observed solutions achieve efficient coordination between generation, storage and demand, thus limiting the benefits of curtailing clean energy.

Conclusions and future perspectives

As society needs to address global climate ambitions and reduce emissions of greenhouse gases, there is an increasing expectation on electrification of new energy end-uses, like transport and heating. Variable renewables are becoming an increasingly attractive option to meet the growing electricity demand, supported by favourable policy frameworks and technological developments that are reducing costs. However, while power systems are designed to handle fluctuating loads, the additional variability and uncertainty of generation pose new challenges for system operators. Failure to deal with this challenge can jeopardize the reliability of power systems as well as the attainment of decarbonization targets. New operational and technical solutions are therefore required to integrate higher penetrations of renewable energy and accommodate the growing supply-side variability.

One of the key solution that lies at the core of power system transitions is the digitalization of the electricity grid. Connecting generation and consumers through smart devices and active metering infrastructures allows for greater operation transparency, therefore helping to achieve more efficient and flexible energy use. Grid automation technologies have a tremendous potential for contributing to sustainable operations by delivering exceptional environmental value. However, while connectivity in distribution networks is key for achieving efficient energy use, a coordinated effort between decision-makers and consumers is critical for unlocking such potential.

Grid digitalization for industrial application

In **Chapter 1**, the integration of carbon forecasts in the control strategy of an industrial batch process demonstrates the environmental benefit of grid digitalization in industrial applications. In the proposed use case, the predicted emission profile is used as a control signal to schedule the operations with minimum emissions targets. Exploiting the process energy flexibility, the optimizer achieves a significant reduction in emissions through load shifting. As demonstrated by the results, the process emissions are reduced by 17.5% and the RE share of the purchased electricity increases by 9.7pp relative to BAU. The analysis is further extended to investigate the effect of different grid conditions on the controller performance by simulating the process in different European countries.

The study led to the conclusion that the environmental benefit is typically more significant (ca. 30%) in countries with a high RE share, while smaller improvements are obtained in countries with a fossil-based energy system (ca. 5%). Although offering enormous potential for emissions reduction, a similar control strategy can penalise the costs of production compared to operating schedules aimed at cost optimization. Motivated by the comparison between the two competing scenarios, a novel methodology for carbon taxation in industry is proposed in the final part of the chapter. This tax, calculated by balancing between the avoided emissions and increased costs, represents the minimum cost that should be associated with emissions to engage industries in operating strategies aimed at environmental protection. Pertinent mechanisms and policies are therefore required to incentivise environmental solutions and avoid missing the significant potential of grid digitalization in industry.

The results of Chapter 1 are based on the implementation of the presented carbon abatement strategy in a single batch process, which is considered as a reference case. However, widespread adoption of such a strategy in the industry would inevitably lead to significant changes in electricity demand and generation motivated by grid balancing requirements. For this reason, the work could be extended by including (i) appropriate modelling of marginal emissions rates and (ii) communications between the involved parties to ensure coordinated consumption. In addition, the obtained carbon tax significantly varies with the accuracy of the forecast. High precision in the prediction leads to increased environmental benefits and therefore to low carbon taxation. Such effect is substantial when the electricity cost and the grid carbon intensity are weakly correlated. Further research should address the effect of prediction accuracy on the carbon tax and, by extension, the required frequency of model retraining that would ensure adequate prediction performance over time.

Demand-side response

Demand-side flexibility can also play a significant role in handling variability of electricity systems and therefore contribute towards balancing the grid. The use of demand response to balance the system during frequent events of substantial excess or deficit of renewable generation contribute to system flexibility by consuming active power. As a result, demand-side response could be considered part of a portfolio of solutions that can facilitate the deployment of variable renewable energy. Moreover, the expected electrification could stimulate the origination of competitive markets in ancillary services and encourage industry to provide responsive loads. As a consequence, fair remuneration strategies should be identified to compensate the increase in operating costs and open the way for flexible industrial consumers.

Chapter 2 investigates the influence of responsive loads on marginal cost due to power restrictions imposed on industrial consumers. The method follows a demand-side response strategy aimed at minimizing the incremental cost due to corrective actions triggered by unexpected events, i.e. power restrictions. A prediction-based optimizer with a daily time horizon is applied to an industrial batch process (same of Chapter 1) and simulated over one month. A scheduling model is embedded in the controller using a MILP formulation and solved at each shift of the rolling window. Restrictions on the electricity consumption profile are simulated using a Monte Carlo approach with drawing from a Sobol sequence and implemented as operating constraints. The proposed method allows quantification of the compensation required by industrial consumers to providing flexibility services. Such compensation could either represent a starting value for the stipulation of fair flexibility contracts, or a minimum bid in a competitive market of ancillary services.

Moreover, the study introduces the concept of industrial processes as "equivalent battery" for the electrical grid. From the perspective of the grid, the processes behave as a battery with capacity related to their buffer size. Reactive scheduling applied to industry can therefore mimic storage by displacing energy-intensive operations to off-peak electricity times.

Although flexible industrial consumers can contribute to grid stability, excessive rescheduling might lead to irregular operation of the production equipment and personnel, therefore compromising the resource efficiency of the process. Such effects are presently disregarded, hence further studies would be required to address the sustainability of the presented approach. The implications of flexible operations also vary depending on the process type and constraints. Therefore, extending the analysis to different processes is crucial to realistically estimate the total potential of grid flexibility services that could be provided by the European industrial sector.

The fundamental role of electricity storage

There is a growing consensus that energy storage solutions will be crucial to ensure the integration of renewable energy sources into power grids at the lowest cost. As prices continue to drop, new storage technologies are emerging, offering cost-effective alternatives to the traditional pump hydro storage. Robust and affordable future energy systems based on renewable generation rely on the capacity to store substantial electricity both on the short and long timescales.

Chapter 3 proposes a complete modelling framework for large-scale power grids with deep electrification of the energy end-use in Europe. The model takes into consideration various system constraints, such as resource availability, current capacities and available potentials to generate viable and realistic designs of the grid. Both isolated and cooperative designs of the grid are proposed and compared in terms of costs and emissions. Several types of batteries and power-to-gas technologies are considered to emphasise differences between competing storage options. Overall, the work presented in this chapter accounts for large number of variables – generation shares, technology choices, curtailments, grid interconnections – and metrics, such as frequently overlooked environmental indicators, to develop a consistent framework for the design and operation of the future European power grids.

The results of this chapter demonstrate that deep electrification causes an imbalance of the seasonal consumption due to an increased weather dependency which consequently affect technology choices. Indeed, the stronger seasonality of demand significantly influence the design of the generation mix by favouring wind-based technologies over PV: in the interconnected scenario generation from wind accounts for 73% of the total electricity output. Additionally, the complementary patterns of solar and wind, which are found in several countries, can be exploited to reduce the need for storage. However, while solar PV contribute to compensating wind shortages, its use has to be balanced against the risk of increasing long-term storage requirements due to a stronger seasonal cycle.

Successfully dealing with intermittent renewables entails either a massive overbuilding of generation or grid designs based on storage. This chapter provides a detailed comparison between these two options by demonstrating that strategies exclusively based on overbuilt solar and wind are unfeasible in several European countries. Moreover, while system expansion allows for an European grid design based on overbuilt generation without storage, the carbon emissions associated with a similar solution would be 50% higher compared to an optimal scenario with storage.

Further improvements of Chapter 3 could include (i) electricity generation from biomass to reduce overbuilding requirements, (ii) modelling of hydro storage as alternative option to P2G (iii) detailed information about regional potentials to allow estimation of grid reinforcement needs and costs, (iv) electrification of demand in industry and (v) other types of chemical storage, by expanding the C1-chemicals sector, focusing on methanol, formic acid and other alternative chemical commodities that might play a significant role in the energy transition.

Transmission expansion

Introducing higher shares of renewable energy into power systems is key for addressing the challenge of meeting a growing electricity demand while coping with environmental standards. Yet the variable and heterogeneous nature of renewables calls for integrated approaches based on cooperation and appropriate regulatory frameworks. It is the uneven distribution of renewable sources that lays not only the foundation for cooperative schemes, but also for unequal economic efforts. Elucidating the benefits of cooperation can contribute to a more informed discussion between stakeholders.

The work presented in **Chapter 4** focuses on quantifying the gains attained through cooperation among European countries. The results demonstrate that transmission expansion reduces the cost (-18%) and carbon emissions (-24%) of the system build-out as a consequence of lower storage and generation needs. This effect is due to a more reliable renewable output from large geography compared to smaller isolated systems. Additionally, complementary demand patterns of the interconnected grids decrease the intensity of the load ramps, therefore leading to lower need for peaking capability.

A European partnership can benefit system costs, but it entails an unequal distribution of efforts that might deter penalised countries from participating. The cost abatement is unevenly distributed among participants, with smaller countries benefiting the most from the cooperation. This effect is due to the greater overall resource availability of the shared grid, which is otherwise limited in smaller areas. Comparing the reduced LCOE to the uniform price of the shared network allows derivation of a novel approach to estimate the economic value of the energy security service in Europe. The proposed scheme is based on impartial sharing of the monetary benefits (total of 130 bn EUR) that are obtained by transitioning from an independent design with isolated grids to a fully interconnected solution in which Europe acts as a single coordinated entity. As a result, grid designs based on cooperation are economically attractive solutions, which are advantageous to all participants provided that an incentive scheme is established.

The 100% renewable Europe

Transitioning to renewable-based generation with expanded transmission and storage reduces the electricity carbon emissions from current levels by almost 90%. When electrification of demand is considered, the interconnected system achieves 85% reduction in the environmental intensity of the European economy. Such improvement corresponds to 2000 Mt of avoided CO_2 emissions each year, or approximately 5% of the annual global carbon emission. The cost of this unprecedented build-out of the energy system is estimated to equal 7 trillion EUR. In equivalent annual terms, this amount corresponds to 4.2% of the European gross domestic product when grids are interconnected and to an average of 5% for the isolated scenario. These estimates suggest that Europe should increase its investment effort on grid infrastructure by at least 15 times. Indeed all the energy systems modelled in this work install substantial capacities of clean resources – the best observed interconnected scenario requires 2.4 TW of renewable generation with 154 TWh and 2 TWh of long- and short-term storage, respectively – demonstrating the importance of the near-term deployment of renewable technologies and storage in the pursuit of urgent climate targets.

All interconnected scenarios modelled in this work are obtained by assuming average capacity factors of generation technologies at the continental scale, meaning that renewable installation is proportionally allocated to a country available potential. Such simplification can lead to overestimation of cost and emissions associated with electricity consumption. The inclusion of country-dependent capacity factors and national exchanges would allow for increasing the share of electricity supplied from inexpensive renewables. Balancing between the reduced cost of generation and the investment in grid reinforcement would provide a means for identifying optimal grid designs for transmission expansion. In addition, the calculation of the equivalent battery potential associated with the whole European industrial sector (see Chapter 2) would allow the estimation of the industrial contribution to the short-term storage and, consequently, its effect on energy costs and emissions in the 100% renewable Europe.

Appendix

(Chapter 1)

A

A.1 Environmental impact factors by country

	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
Country	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	1.00	0.99	4.03	4.44	11.66	0.016
Belarus	-	-	-	-	-	-
Belgium	1.00	0.99	4.03	4.44	11.66	0.016
Bosnia and Herz.	1.00	0.99	4.03	4.44	11.66	0.016
Bulgaria	1.00	0.99	4.03	4.44	11.66	0.016
Croatia	1.00	0.99	4.03	4.44	11.66	0.016
Cyprus	-	-	-	-	-	-
Czechia	1.00	0.99	4.03	4.44	11.66	0.016
Denmark	1.00	0.99	4.03	4.44	11.66	0.016
Estonia	1.00	0.99	4.03	4.44	11.66	0.016
Finland	1.00	0.99	4.03	4.44	11.66	0.016
France	1.00	0.99	4.03	4.44	11.66	0.016
Germany	1.00	0.99	4.03	4.44	11.66	0.016
Greece	1.00	0.99	4.03	4.44	11.66	0.016
Hungary	1.00	0.99	4.03	4.44	11.66	0.016
Ireland	1.00	0.99	4.03	4.44	11.66	0.016
Italy	1.00	0.99	4.03	4.44	11.66	0.016
Latvia	1.00	0.99	4.03	4.44	11.66	0.016
Lithuania	1.00	0.99	4.03	4.44	11.66	0.016
Luxembourg	1.00	0.99	4.03	4.44	11.66	0.016
Macedonia	1.00	0.99	4.03	4.44	11.66	0.016
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	1.00	0.99	4.03	4.44	11.66	0.016
Norway	-	-	-	-	-	-
Poland	1.00	0.99	4.03	4.44	11.66	0.016
Portugal	1.00	0.99	4.03	4.44	11.66	0.016
Romania	1.00	0.99	4.03	4.44	11.66	0.016
Russia	1.00	0.99	4.26	4.74	12.11	0.016
Serbia	1.00	0.99	4.03	4.44	11.66	0.016
Slovakia	1.00	0.99	4.03	4.44	11.66	0.016
Slovenia	1.00	0.99	4.03	4.44	11.66	0.016
Spain	1.00	0.99	4.03	4.44	11.66	0.016
Sweden	1.00	0.99	4.03	4.44	11.66	0.016
Switzerland	1.00	0.99	3.47	3.84	10.95	0.014
Turkey	1.00	0.99	4.26	4.74	12.11	0.016
Ukraine	1.00	0.99	4.03	4.44	11.66	0.016
United Kingdom	1.00	0.99	4.03	4.44	11.66	0.016
Europe	1.00	0.99	4.03	4.44	11.67	0.016

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.1 – Environmental impact factors [41] of electricity generation from hydro run-of-river by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
Country	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	1.00	0.99	6.17	7.38	30.78	0.020
Belarus	-	-	-	-	-	-
Belgium	-	-	-	-	-	-
Bosnia and Herz.	1.00	0.99	6.17	7.38	30.78	0.020
Bulgaria	-	-	-	-	-	-
Croatia	1.00	0.99	6.17	7.38	30.78	0.020
Cyprus	-	-	-	-	-	-
Czechia	1.00	0.99	50.56	62.30	50.99	0.155
Denmark	-	-	-	-	-	-
Estonia	-	-	-	-	-	-
Finland	1.00	0.99	50.56	62.30	50.99	0.155
France	1.00	0.99	6.17	7.38	30.78	0.020
Germany	1.00	0.99	50.56	62.30	50.99	0.155
Greece	-	-	-	-	-	-
Hungary	-	-	-	-	-	-
Ireland	-	-	-	-	-	-
Italy	1.00	0.99	6.17	7.38	30.78	0.020
Latvia	-	-	-	-	-	-
Lithuania	-	-	-	-	-	-
Luxembourg	-	-	-	-	-	-
Macedonia	1.00	0.99	6.17	7.38	30.78	0.020
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	-	-	-	-	-	-
Norway	1.00	0.99	6.17	7.38	30.78	0.020
Poland	-	-	-	-	-	-
Portugal	1.00	0.99	50.56	62.30	50.99	0.155
Romania	-	-	-	-	-	-
Russia	1.00	0.99	50.97	62.82	51.66	0.156
Serbia	1.00	0.99	6.17	7.38	30.78	0.020
Slovakia	1.00	0.99	50.56	62.30	50.99	0.155
Slovenia	-	-	-	-	-	-
Spain	1.00	0.99	50.56	62.30	50.99	0.155
Sweden	1.00	0.99	50.56	62.30	50.99	0.155
Switzerland	1.00	0.99	6.17	7.38	30.79	0.020
Turkey	1.00	0.99	50.97	62.82	51.66	0.156
Ukraine	-	-	-	-	-	-
United Kingdom	-	-	-	-	-	-
Europe	1.00	0.99	28.41	34.90	40.96	0.088

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.2 – Environmental impact factors [41] of electricity generation from hydro reservoir by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

Country	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	1.00	0.35	489.18	541.05	399.74	1.633
Belarus	-	-	-	-	-	-
Belgium	1.00	0.08	400.36	447.95	514.91	3.243
Bosnia and Herz.	-	-	-	-	-	-
Bulgaria	1.00	0.06	839.83	866.95	968.39	3.614
Croatia	1.00	0.23	735.80	789.40	843.36	2.428
Cyprus	-	-	-	-	-	-
Czechia	1.00	0.04	1377.59	1455.35	1121.66	4.879
Denmark	-	-	-	-	-	-
Estonia	-	-	-	-	-	-
Finland	-	-	-	-	-	-
France	1.00	0.06	125.61	139.68	497.74	3.341
Germany	1.00	0.10	945.91	1043.70	712.27	3.073
Greece	1.00	0.08	1193.43	1290.72	1077.06	3.193
Hungary	-	-	-	-	-	-
Ireland	1.00	0.14	765.75	826.55	596.50	2.102
Italy	1.00	0.18	634.14	739.11	519.70	1.875
Latvia	-	-	-	-	-	-
Lithuania	1.00	0.32	537.64	598.58	541.15	2.215
Luxembourg	1.00	0.09	778.43	860.81	651.68	3.125
Macedonia	-	-	-	-	-	-
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	-	-	-	-	-	-
Norway	1.00	0.92	30.63	35.04	71.20	0.163
Poland	1.00	0.09	1411.30	1548.07	1191.07	3.886
Portugal	1.00	0.33	580.50	657.36	492.39	1.653
Romania	1.00	0.17	614.04	640.54	1287.37	2.635
Russia	1.00	0.06	1059.65	1223.43	1075.76	3.397
Serbia	1.00	0.11	1306.82	1332.32	1977.39	3.627
Slovakia	1.00	0.07	767.71	830.85	847.18	3.889
Slovenia	1.00	0.17	616.61	646.96	773.79	2.690
Spain	1.00	0.18	497.97	557.63	579.79	2.403
Sweden	1.00	0.32	117.77	136.69	284.90	1.961
Switzerland	-	-	-	-	-	-
Turkey	-	-	-	-	-	-
Ukraine	1.00	0.02	915.22	1037.95	1058.42	4.432
United Kingdom	1.00	0.13	581.12	633.02	578.65	2.857
Europe	1.00	0.18	721.79	786.65	777.59	2.847

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.3 – Environmental impact factors [41] of electricity generation from hydro pumped storage by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

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Country	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	1.00	0.94	16.78	19.88	45.87	0.047
Belarus	-	-	-	-	-	-
Belgium	1.00	0.95	15.71	18.58	46.19	0.044
Bosnia and Herz.	-	-	-	-	-	-
Bulgaria	1.00	0.94	18.71	22.12	59.98	0.052
Croatia	1.00	0.95	15.97	18.95	42.78	0.045
Cyprus	1.00	0.92	23.25	27.58	60.01	0.065
Czechia	1.00	0.94	18.27	21.68	48.20	0.051
Denmark	1.00	0.96	12.67	15.05	40.53	0.035
Estonia	1.00	0.94	18.68	22.12	50.91	0.052
Finland	1.00	0.93	22.62	26.62	82.95	0.062
France	1.00	0.95	14.72	17.45	39.55	0.041
Germany	1.00	0.94	19.09	22.62	55.01	0.053
Greece	1.00	0.95	14.45	17.12	45.38	0.040
Hungary	1.00	0.96	12.86	15.23	36.13	0.036
Ireland	1.00	0.96	12.92	15.32	36.75	0.036
Italy	1.00	0.94	18.68	22.16	54.69	0.052
Latvia	1.00	0.95	17.13	20.41	47.56	0.048
Lithuania	1.00	0.96	12.62	14.94	36.20	0.035
Luxembourg	1.00	0.94	17.47	20.75	46.74	0.049
Macedonia	1.00	0.95	15.77	18.69	41.63	0.044
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	1.00	0.95	15.68	18.56	50.36	0.044
Norway	1.00	0.95	13.56	16.06	37.74	0.038
Poland	1.00	0.95	15.56	18.44	41.89	0.044
Portugal	1.00	0.96	12.94	15.33	34.98	0.036
Romania	1.00	0.92	24.28	28.66	75.98	0.067
Russia	1.00	0.77	94.47	113.14	258.64	0.268
Serbia	-	-	-	-	-	-
Slovakia	1.00	0.96	14.07	16.85	41.79	0.040
Slovenia	-	-	-	-	-	-
Spain	1.00	0.96	13.35	15.88	37.28	0.038
Sweden	1.00	0.95	15.31	18.17	41.40	0.043
Switzerland	-	-	-	-	-	-
Turkey	1.00	0.96	12.63	14.94	39.22	0.035
Ukraine	1.00	0.91	30.63	36.23	89.43	0.085
United Kingdom	1.00	0.96	13.12	15.55	37.94	0.037
Europe	1.00	0.94	19.16	22.74	54.96	0.054

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.4 – Environmental impact factors [41] of electricity generation from wind onshore by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

Country	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	-	-	-	-	-	-
Belarus	-	-	-	-	-	-
Belgium	1.00	0.95	15.35	18.12	41.11	0.040
Bosnia and Herz.	-	-	-	-	-	-
Bulgaria	-	-	-	-	-	-
Croatia	-	-	-	-	-	-
Cyprus	-	-	-	-	-	-
Czechia	-	-	-	-	-	-
Denmark	1.00	0.95	15.35	18.12	41.11	0.040
Estonia	-	-	-	-	-	-
Finland	1.00	0.95	15.35	18.12	41.11	0.040
France	1.00	0.95	15.35	18.12	41.11	0.040
Germany	1.00	0.95	15.35	18.12	41.11	0.040
Greece	-	-	-	-	-	-
Hungary	-	-	-	-	-	-
Ireland	1.00	0.95	15.35	18.12	41.11	0.040
Italy	-	-	-	-	-	-
Latvia	-	-	-	-	-	-
Lithuania	-	-	-	-	-	-
Luxembourg	-	-	-	-	-	-
Macedonia	-	-	-	-	-	-
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	1.00	0.95	15.35	18.12	41.11	0.040
Norway	1.00	0.95	15.35	18.12	41.11	0.040
Poland	-	-	-	-	-	-
Portugal	1.00	0.95	15.35	18.12	41.11	0.040
Romania	-	-	-	-	-	-
Russia	-	-	-	-	-	-
Serbia	-	-	-	-	-	-
Slovakia	-	-	-	-	-	-
Slovenia	-	-	-	-	-	-
Spain	1.00	0.95	15.35	18.12	41.11	0.040
Sweden	1.00	0.95	15.35	18.12	41.11	0.040
Switzerland	-	-	-	-	-	-
Turkey	-	-	-	-	-	-
Ukraine	-	-	-	-	-	-
United Kingdom	1.00	0.95	15.35	18.12	41.11	0.040
Europe	1.00	0.95	15.35	18.12	41.11	0.040

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.5 – Environmental impact factors [41] of electricity generation from wind offshore by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

A

Country	RE share [-] Method 1 [1]	RE share [-] Method 2 [2]	Climate change [gCO_2eq/kWh] GWP100a	Climate change [gCO_2eq/kWh] GWP20a	Ecological scarcity [UBP/kWh] Total	Ecological footprint [m2a/kWh] Total
Albania	-	-	-	-	-	-
Austria	1.00	0.71	131.50	226.42	358.20	2.432
Belarus	-	-	-	-	-	-
Belgium	1.00	0.87	90.81	133.38	375.67	3.026
Bosnia and Herz.	-	-	-	-	-	-
Bulgaria	1.00	0.24	253.80	506.68	315.85	0.651
Croatia	1.00	0.51	185.09	351.02	368.66	1.669
Cyprus	1.00	0.12	284.18	575.11	293.19	0.208
Czechia	1.00	0.88	87.96	126.93	377.00	3.068
Denmark	1.00	0.87	91.94	135.98	375.18	3.010
Estonia	1.00	0.92	81.79	116.99	447.99	3.198
Finland	1.00	0.90	82.42	114.21	379.27	3.149
France	1.00	0.79	112.49	182.96	366.37	2.709
Germany	1.00	0.26	249.81	496.91	307.39	0.704
Greece	1.00	0.14	279.79	565.46	294.51	0.266
Hungary	1.00	0.89	86.81	124.30	377.48	3.085
Ireland	1.00	0.70	135.59	235.80	356.48	2.372
Italy	1.00	0.33	230.87	453.62	315.53	0.980
Latvia	1.00	0.64	152.53	277.28	393.65	2.151
Lithuania	1.00	0.87	94.96	146.85	437.87	3.003
Luxembourg	1.00	0.95	69.56	84.82	384.85	3.337
Macedonia	-	-	-	-	-	-
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	1.00	0.92	77.28	102.44	381.49	3.224
Norway	1.00	0.69	137.48	240.10	355.64	2.344
Poland	1.00	0.88	89.33	130.03	376.39	3.048
Portugal	1.00	0.95	69.55	84.82	384.83	3.337
Romania	1.00	0.88	88.63	128.45	376.78	3.058
Russia	-	-	-	-	-	-
Serbia	-	-	-	-	-	-
Slovakia	1.00	0.73	127.64	217.64	359.95	2.488
Slovenia	1.00	0.38	216.69	421.21	321.61	1.187
Spain	1.00	0.85	95.03	143.08	373.92	2.965
Sweden	1.00	0.94	71.93	90.21	383.78	3.302
Switzerland	1.00	0.82	101.47	162.87	353.63	1.740
Turkey	1.00	0.15	278.82	563.21	296.81	0.281
Ukraine	-	-	-	-	-	-
United Kingdom	1.00	0.95	69.55	84.79	384.82	3.337
Europe	1.00	0.69	137.51	240.79	362.49	2.311

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.6 – Environmental impact factors [41] of electricity generation from biomass by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

A

Country	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	-	-	-	-	-	-
Belarus	-	-	-	-	-	-
Belgium	-	-	-	-	-	-
Bosnia and Herz.	-	-	-	-	-	-
Bulgaria	-	-	-	-	-	-
Croatia	-	-	-	-	-	-
Cyprus	-	-	-	-	-	-
Czechia	-	-	-	-	-	-
Denmark	-	-	-	-	-	-
Estonia	-	-	-	-	-	-
Finland	-	-	-	-	-	-
France	1.00	0.89	69.27	80.28	96.82	0.195
Germany	1.00	0.89	69.27	80.28	96.82	0.195
Greece	-	-	-	-	-	-
Hungary	-	-	-	-	-	-
Ireland	-	-	-	-	-	-
Italy	1.00	0.89	69.27	80.28	96.82	0.195
Latvia	-	-	-	-	-	-
Lithuania	-	-	-	-	-	-
Luxembourg	-	-	-	-	-	-
Macedonia	-	-	-	-	-	-
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	-	-	-	-	-	-
Norway	-	-	-	-	-	-
Poland	-	-	-	-	-	-
Portugal	1.00	0.89	69.27	80.28	96.82	0.195
Romania	-	-	-	-	-	-
Russia	1.00	0.89	69.27	80.28	96.82	0.195
Serbia	-	-	-	-	-	-
Slovakia	-	-	-	-	-	-
Slovenia	-	-	-	-	-	-
Spain	-	-	-	-	-	-
Sweden	-	-	-	-	-	-
Switzerland	-	-	-	-	-	-
Turkey	1.00	0.89	69.27	80.28	96.82	0.195
Ukraine	-	-	-	-	-	-
United Kingdom	-	-	-	-	-	-
Europe	1.00	0.89	69.27	80.28	96.82	0.195

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.7 – Environmental impact factors [41] of electricity generation from geothermal by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

A

Country	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	1.00	0.93	43.27	51.37	64.58	0.217
Belarus	-	-	-	-	-	-
Belgium	1.00	0.80	88.18	106.12	210.26	0.890
Bosnia and Herz.	1.00	0.99	4.78	5.47	18.35	0.017
Bulgaria	1.00	0.85	90.36	101.31	144.85	0.340
Croatia	1.00	0.94	33.78	44.07	68.86	0.158
Cyprus	1.00	0.86	45.98	60.80	105.49	0.110
Czechia	1.00	0.71	257.53	283.06	348.96	1.219
Denmark	1.00	0.92	35.36	47.13	122.82	0.645
Estonia	1.00	0.93	52.52	73.11	265.25	1.758
Finland	1.00	0.97	28.69	37.18	94.45	0.608
France	1.00	0.90	25.77	30.85	77.74	0.274
Germany	1.00	0.74	110.95	165.95	174.52	0.329
Greece	1.00	0.91	34.88	43.27	84.57	0.091
Hungary	1.00	0.90	60.48	82.77	237.68	1.675
Ireland	1.00	0.91	49.40	60.65	78.15	0.275
Italy	1.00	0.82	70.93	108.46	123.23	0.259
Latvia	1.00	0.93	31.11	53.87	81.39	0.399
Lithuania	1.00	0.80	143.80	165.12	201.04	0.854
Luxembourg	1.00	0.27	614.51	680.26	536.04	2.495
Macedonia	1.00	0.98	7.49	8.86	30.88	0.024
Malta	1.00	0.82	67.52	78.67	174.05	0.184
Montenegro	-	-	-	-	-	-
Netherlands	1.00	0.90	42.87	51.39	133.78	0.424
Norway	1.00	0.99	6.48	7.76	31.25	0.022
Poland	1.00	0.91	66.59	82.25	154.08	0.911
Portugal	1.00	0.94	41.45	48.26	60.36	0.186
Romania	1.00	0.94	29.47	33.10	75.23	0.123
Russia	1.00	0.98	27.77	32.92	34.66	0.088
Serbia	1.00	0.93	86.66	88.80	138.86	0.244
Slovakia	1.00	0.90	65.79	78.31	110.58	0.378
Slovenia	1.00	0.90	51.29	61.00	83.66	0.214
Spain	1.00	0.92	40.47	47.77	75.73	0.224
Sweden	1.00	0.98	17.26	20.87	44.19	0.221
Switzerland	1.00	0.97	12.26	16.38	43.94	0.105
Turkey	1.00	0.96	31.81	42.11	43.10	0.087
Ukraine	1.00	0.82	146.91	166.84	187.83	0.690
United Kingdom	1.00	0.88	66.35	76.44	176.92	0.969
Europe	1.00	0.88	73.08	87.29	128.82	0.492

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.8 – Environmental impact factors [41] of electricity generation from other renewable sources by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

A

Country	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	-	-	-	-	-	-
Belarus	-	-	-	-	-	-
Belgium	0.00	0.00	11.32	12.51	318.50	2.624
Bosnia and Herz.	-	-	-	-	-	-
Bulgaria	0.00	0.00	11.32	12.51	318.50	2.624
Croatia	-	-	-	-	-	-
Cyprus	-	-	-	-	-	-
Czechia	0.00	0.00	11.32	12.51	318.50	2.624
Denmark	-	-	-	-	-	-
Estonia	-	-	-	-	-	-
Finland	0.00	0.00	11.91	13.23	335.07	2.730
France	0.00	0.00	11.01	12.21	369.44	2.764
Germany	0.00	0.00	10.93	12.10	321.58	2.422
Greece	-	-	-	-	-	-
Hungary	0.00	0.00	11.32	12.51	318.50	2.624
Ireland	-	-	-	-	-	-
Italy	-	-	-	-	-	-
Latvia	-	-	-	-	-	-
Lithuania	-	-	-	-	-	-
Luxembourg	-	-	-	-	-	-
Macedonia	-	-	-	-	-	-
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	0.00	0.00	11.32	12.51	318.50	2.624
Norway	-	-	-	-	-	-
Poland	-	-	-	-	-	-
Portugal	-	-	-	-	-	-
Romania	0.00	0.00	16.72	18.98	2321.98	3.117
Russia	0.00	0.00	12.43	13.81	346.46	2.833
Serbia	-	-	-	-	-	-
Slovakia	0.00	0.00	11.32	12.51	318.50	2.624
Slovenia	0.00	0.00	11.32	12.51	318.50	2.624
Spain	0.00	0.00	11.42	12.65	323.63	2.657
Sweden	0.00	0.00	11.97	13.30	336.73	2.741
Switzerland	0.00	0.00	10.65	11.80	329.02	2.695
Turkey	-	-	-	-	-	-
Ukraine	0.00	0.00	11.80	13.05	332.33	2.739
United Kingdom	0.00	0.00	12.06	13.42	341.00	2.769
Europe	0.00	0.00	11.77	13.07	446.28	2.696

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.9 – Environmental impact factors [41] of electricity generation from nuclear by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

A

Country	RE share [-] Method 1 [1]	RE share [-] Method 2 [2]	Climate change [gCO_2eq/kWh] GWP100a	Climate change [gCO_2eq/kWh] GWP20a	Ecological scarcity [UBP/kWh] Total	Ecological footprint [m2a/kWh] Total
Albania	-	-	-	-	-	-
Austria	0.00	0.01	991.14	1127.58	644.27	2.474
Belarus	-	-	-	-	-	-
Belgium	0.00	0.01	1083.57	1239.11	881.04	2.711
Bosnia and Herz.	0.00	0.00	1308.50	1327.63	1600.88	3.490
Bulgaria	0.00	0.00	1145.28	1170.04	1007.45	3.049
Croatia	0.00	0.01	1107.52	1263.18	883.00	2.785
Cyprus	-	-	-	-	-	-
Czechia	0.00	0.00	1568.52	1622.17	1104.92	4.147
Denmark	0.00	0.01	980.98	1111.12	641.15	2.454
Estonia	0.00	0.00	1303.43	1326.78	794.21	3.451
Finland	0.00	0.01	1031.70	1138.55	673.48	2.617
France	0.00	0.01	1071.34	1232.62	931.77	2.676
Germany	0.00	0.01	1152.26	1223.10	741.94	2.990
Greece	0.00	0.00	1399.15	1431.34	1265.73	3.734
Hungary	0.00	0.00	1404.00	1431.91	977.42	3.741
Ireland	0.00	0.01	1023.14	1125.67	767.61	2.616
Italy	0.00	0.01	1070.27	1213.71	866.88	2.687
Latvia	-	-	-	-	-	-
Lithuania	-	-	-	-	-	-
Luxembourg	-	-	-	-	-	-
Macedonia	0.00	0.00	1446.60	1469.15	2441.72	3.850
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	0.00	0.01	992.80	1127.39	653.81	2.484
Norway	0.00	0.01	1386.39	1570.06	911.83	3.468
Poland	0.00	0.01	1166.41	1277.21	976.25	2.999
Portugal	0.00	0.01	1057.68	1197.61	871.26	2.669
Romania	0.00	0.00	1158.50	1178.15	1221.92	3.089
Russia	0.00	0.01	1751.69	1903.32	2517.33	4.500
Serbia	0.00	0.00	1284.03	1305.49	1946.00	3.421
Slovakia	0.00	0.01	1494.50	1569.10	1568.86	3.911
Slovenia	0.00	0.00	1244.75	1263.46	1393.35	3.320
Spain	0.00	0.01	1136.22	1278.19	1157.71	2.875
Sweden	0.00	0.01	1230.43	1358.76	868.02	3.120
Switzerland	-	-	-	-	-	-
Turkey	0.00	0.01	1178.61	1263.20	2678.60	3.047
Ukraine	0.00	0.01	1383.93	1569.40	1272.70	3.483
United Kingdom	0.00	0.01	1056.76	1205.46	871.59	2.658
Europe	0.00	0.01	1220.34	1317.35	1171.09	3.151

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.10 – Environmental impact factors [41] of electricity generation from coal by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

A

Country	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	0.00	0.00	589.85	717.00	359.67	1.389
Belarus	-	-	-	-	-	-
Belgium	0.00	0.01	622.74	679.38	361.40	1.579
Bosnia and Herz.	-	-	-	-	-	-
Bulgaria	0.00	0.00	940.20	1038.98	601.85	2.364
Croatia	0.00	0.00	600.04	662.41	376.49	1.509
Cyprus	-	-	-	-	-	-
Czechia	0.00	0.01	918.63	1042.82	532.13	2.272
Denmark	0.00	0.00	502.73	516.69	326.14	1.319
Estonia	0.00	0.00	563.14	622.35	360.85	1.416
Finland	0.00	0.01	811.90	909.28	446.72	2.026
France	0.00	0.01	671.72	732.98	403.09	1.703
Germany	0.00	0.00	541.74	615.90	340.65	1.336
Greece	0.00	0.00	672.36	841.81	403.73	1.548
Hungary	0.00	0.00	709.87	887.83	429.83	1.637
Ireland	0.00	0.00	454.52	464.62	346.62	1.196
Italy	0.00	0.00	554.66	648.10	332.70	1.344
Latvia	0.00	0.00	637.46	704.10	404.33	1.603
Lithuania	0.00	0.00	630.35	696.59	403.61	1.585
Luxembourg	0.00	0.00	494.39	545.82	311.20	1.243
Macedonia	0.00	0.00	523.02	577.38	328.20	1.315
Malta	-	-	-	-	-	-
Montenegro	-	-	-	-	-	-
Netherlands	0.00	0.01	536.86	575.52	323.74	1.374
Norway	0.00	0.09	2176.56	2178.57	1047.81	5.807
Poland	0.00	0.01	1046.64	1157.04	565.13	2.633
Portugal	0.00	0.00	438.29	483.73	274.08	1.102
Romania	0.00	0.00	683.19	754.29	436.22	1.719
Russia	0.00	0.00	842.07	1011.59	514.04	2.002
Serbia	0.00	0.00	803.59	888.06	514.92	2.020
Slovakia	0.00	0.00	689.71	862.29	414.38	1.591
Slovenia	0.00	0.00	569.68	629.49	364.86	1.432
Spain	0.00	0.00	523.72	565.95	309.73	1.339
Sweden	0.00	0.03	1572.89	1585.72	821.35	4.178
Switzerland	0.00	0.00	613.51	769.51	380.19	1.384
Turkey	0.00	0.00	453.02	501.62	274.24	1.138
Ukraine	0.00	0.00	968.62	1065.72	613.42	2.442
United Kingdom	0.00	0.00	514.33	533.33	345.22	1.342
Europe	0.00	0.01	723.39	802.01	432.38	1.815

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.11 – Environmental impact factors [41] of electricity generation from gas by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

A

	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
Country	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	0.00	0.00	1038.85	1062.09	776.48	2.717
Belarus	-	-	-	-	-	-
Belgium	0.00	0.00	857.39	878.27	778.28	2.244
Bosnia and Herz.	0.00	0.00	1067.50	1093.54	1019.88	2.794
Bulgaria	0.00	0.00	1530.81	1573.03	2395.32	3.997
Croatia	0.00	0.00	929.19	952.18	1030.56	2.431
Cyprus	0.00	0.00	1033.88	1059.63	988.19	2.701
Czechia	0.00	0.00	1354.81	1387.79	1193.83	3.546
Denmark	0.00	0.00	960.02	981.62	1000.13	2.530
Estonia	0.00	0.00	1139.01	1166.54	1087.91	2.981
Finland	0.00	0.00	625.12	640.46	579.62	1.636
France	0.00	0.00	903.58	925.65	933.31	2.365
Germany	0.00	0.00	801.58	820.20	613.53	2.118
Greece	0.00	0.00	962.20	987.45	925.88	2.469
Hungary	0.00	0.00	1076.76	1104.01	1201.08	2.815
Ireland	0.00	0.00	888.92	911.08	1001.79	2.326
Italy	0.00	0.00	902.83	924.07	886.44	2.364
Latvia	-	-	-	-	-	-
Lithuania	0.00	0.00	1480.99	1516.79	1420.53	3.874
Luxembourg	-	-	-	-	-	-
Macedonia	0.00	0.00	984.36	1008.71	1091.91	2.575
Malta	0.00	0.00	1182.03	1210.93	1129.14	3.093
Montenegro	-	-	-	-	-	-
Netherlands	0.00	0.00	1040.37	1066.55	837.58	2.721
Norway	0.00	0.00	469.65	481.19	435.64	1.229
Poland	0.00	0.00	852.02	872.67	751.30	2.230
Portugal	0.00	0.00	767.65	786.55	948.58	2.009
Romania	0.00	0.00	1216.57	1247.48	1367.92	3.181
Russia	0.00	0.00	1116.43	1144.06	1071.89	2.916
Serbia	-	-	-	-	-	-
Slovakia	0.00	0.00	1352.68	1389.86	2115.96	3.532
Slovenia	0.00	0.00	1044.51	1069.69	895.85	2.733
Spain	0.00	0.00	838.74	859.10	787.61	2.195
Sweden	0.00	0.00	811.56	829.51	680.47	2.120
Switzerland	-	-	-	-	-	-
Turkey	0.00	0.00	914.98	937.68	874.70	2.391
Ukraine	0.00	0.00	1142.41	1170.00	1094.99	2.989
United Kingdom	0.00	0.00	1280.46	1313.66	1368.87	3.347
Europe	0.00	0.00	1017.75	1042.88	1040.16	2.662

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.12 – Environmental impact factors [41] of electricity generation from oil by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

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Country	RE share [-]		Climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Albania	-	-	-	-	-	-
Austria	0.00	0.00	684.88	810.17	430.57	1.650
Belarus	-	-	-	-	-	-
Belgium	0.00	0.00	211.04	230.62	335.03	2.293
Bosnia and Herz.	0.00	0.00	1307.53	1326.69	1598.55	3.487
Bulgaria	0.00	0.00	652.15	670.52	695.26	2.835
Croatia	0.00	0.01	932.59	1055.96	708.82	2.345
Cyprus	0.00	0.00	1033.88	1059.63	988.19	2.701
Czechia	0.00	0.00	957.27	995.52	782.69	3.479
Denmark	0.00	0.01	898.32	1007.17	591.06	2.259
Estonia	0.00	0.00	1136.91	1164.59	1082.71	2.975
Finland	0.00	0.00	361.36	400.08	435.10	2.624
France	0.00	0.00	81.53	90.08	384.71	2.686
Germany	0.00	0.00	819.34	875.53	594.21	2.630
Greece	0.00	0.00	1074.68	1156.52	904.08	2.764
Hungary	0.00	0.00	433.55	478.43	471.10	2.625
Ireland	0.00	0.00	654.14	695.92	498.79	1.695
Italy	0.00	0.00	694.93	794.50	491.64	1.718
Latvia	0.00	0.00	637.46	704.10	404.33	1.603
Lithuania	0.00	0.00	645.34	711.05	421.53	1.625
Luxembourg	0.00	0.00	494.39	545.82	311.20	1.243
Macedonia	0.00	0.00	1286.01	1313.69	2065.93	3.409
Malta	0.00	0.00	1182.03	1210.93	1129.14	3.093
Montenegro	-	-	-	-	-	-
Netherlands	0.00	0.01	718.11	797.25	473.67	1.934
Norway	0.00	0.05	1702.44	1748.91	912.55	4.483
Poland	0.00	0.01	1159.70	1270.15	956.35	2.979
Portugal	0.00	0.01	819.60	919.38	659.53	2.070
Romania	0.00	0.00	682.11	702.39	1515.81	2.917
Russia	0.00	0.00	815.06	940.21	850.71	2.671
Serbia	0.00	0.00	1281.57	1303.35	1938.66	3.414
Slovakia	0.00	0.00	264.56	285.93	518.54	2.740
Slovenia	0.00	0.00	570.00	580.44	793.67	2.900
Spain	0.00	0.00	504.59	556.34	595.50	2.408
Sweden	0.00	0.00	47.37	49.92	349.25	2.763
Switzerland	0.00	0.00	22.38	26.54	330.02	2.670
Turkey	0.00	0.00	830.53	897.53	1519.07	2.131
Ukraine	0.00	0.00	609.45	688.23	725.24	3.023
United Kingdom	0.00	0.00	434.21	465.25	417.24	1.964
Europe	0.00	0.01	740.03	792.48	774.46	2.578

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table A.1.13 – Environmental impact factors [41] of electricity generation from other fossil sources by country and all Europe. Values calculated per kWh of consumed electricity. The impact factors of Europe are obtained weighing the indicators of each country by their electricity demand.

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A.2 Accuracy improvement from today's carbon accounting standards

	Accuracy improvement [%]				
Country	**L. Whisker**	**Q1**	**Q2**	**Q3**	**H. Whisker**
Austria	0.08	14.27	27.59	43.25	91.62
Belgium	0.10	10.74	24.11	38.40	77.86
Bulgaria	0.07	4.91	9.75	17.30	50.41
Czechia	0.02	4.04	7.90	13.38	37.60
Denmark	0.01	19.14	39.68	59.08	156.96
Estonia	0.01	14.02	27.75	46.27	83.23
Finland	0.06	9.80	28.07	46.39	133.10
France	0.00	12.98	28.35	46.39	138.02
Germany	0.01	10.25	21.26	34.07	65.22
Greece	0.00	5.17	11.24	19.15	44.61
Hungary	0.01	5.05	10.99	18.64	56.60
Ireland	0.00	14.54	28.42	42.91	69.61
Italy	0.10	4.59	9.54	16.16	48.32
Latvia	0.03	11.42	22.37	36.71	82.43
Lithuania	0.31	14.90	31.05	55.79	246.64
Netherlands	0.04	5.36	10.62	16.27	63.44
Poland	0.00	2.58	5.68	9.30	26.78
Portugal	0.06	15.45	31.29	49.09	104.45
Romania	0.10	6.16	13.60	21.57	47.91
Slovakia	0.01	5.68	11.75	20.84	64.55
Slovenia	0.06	8.60	20.02	36.83	99.01
Spain	0.02	9.46	19.08	30.12	70.30
Sweden	0.05	7.61	14.29	23.39	178.22
Switzerland	0.01	15.32	31.49	47.04	109.57
United Kingdom	0.00	7.43	17.19	30.25	76.62

Table A.2.1 – Distribution of the accuracy improvement from today's carbon accounting standards at the hourly time scale. The lower and higher whiskers correspond to the minimum and maximum relative improvement, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distributions.

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Country	Accuracy improvement [%]				
	L. Whisker	Q1	Q2	Q3	H. Whisker
Austria	0.07	12.56	25.90	41.47	83.08
Belgium	0.08	9.54	21.72	33.69	72.82
Bulgaria	0.05	4.77	9.22	15.11	46.82
Czechia	0.02	3.31	7.28	12.00	34.68
Denmark	0.04	16.33	31.13	53.64	138.32
Estonia	0.09	11.45	25.66	44.25	82.16
Finland	0.00	10.11	26.54	43.56	82.82
France	0.03	13.49	27.57	42.26	119.64
Germany	0.02	8.91	18.11	29.92	60.66
Greece	0.03	4.39	8.41	14.68	33.72
Hungary	0.01	5.26	10.62	17.21	45.50
Ireland	0.00	11.05	23.62	35.06	58.31
Italy	0.05	3.07	7.19	13.34	34.10
Latvia	0.01	7.23	16.56	26.56	69.17
Lithuania	0.07	9.85	22.87	38.83	152.85
Netherlands	0.00	5.13	9.72	15.77	38.49
Poland	0.02	2.17	4.59	7.49	22.90
Portugal	0.07	15.17	29.53	44.02	77.24
Romania	0.00	5.26	10.47	19.28	41.71
Slovakia	0.00	5.38	10.84	19.71	56.07
Slovenia	0.10	9.66	18.92	31.45	88.05
Spain	0.03	8.43	18.13	28.60	70.13
Sweden	0.07	6.71	13.68	20.83	98.91
Switzerland	0.08	11.79	24.31	38.96	85.48
United Kingdom	0.03	5.84	13.39	23.15	64.12

Table A.2.2 – Distribution of the accuracy improvement from today's carbon accounting standards at the daily time scale. The lower and higher whiskers correspond to the minimum and maximum relative improvement, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distributions.

	Accuracy improvement [%]				
Country	**L. Whisker**	**Q1**	**Q2**	**Q3**	**H. Whisker**
Austria	0.01	11.89	23.90	38.27	59.41
Belgium	0.13	9.52	17.64	26.68	52.96
Bulgaria	0.08	5.14	8.17	12.15	42.45
Czechia	0.01	2.81	5.81	8.58	19.93
Denmark	0.01	9.95	20.51	39.73	104.13
Estonia	0.03	9.02	20.13	35.07	71.48
Finland	0.04	10.89	25.72	43.34	76.30
France	0.08	8.67	20.26	36.30	107.15
Germany	0.03	5.27	10.73	19.28	49.62
Greece	0.01	2.29	5.83	10.19	21.83
Hungary	0.05	4.49	8.59	14.36	32.17
Ireland	0.01	5.61	12.44	21.87	40.17
Italy	0.03	3.09	5.91	9.30	27.47
Latvia	0.07	5.99	12.08	20.97	56.71
Lithuania	0.04	6.34	16.88	30.13	115.88
Netherlands	0.02	5.96	8.72	13.03	22.96
Poland	0.01	1.53	3.33	5.84	12.94
Portugal	0.09	8.48	17.95	29.06	65.47
Romania	0.05	5.07	9.35	14.83	34.85
Slovakia	0.05	4.40	9.73	16.75	41.38
Slovenia	0.14	10.31	18.13	30.98	72.60
Spain	0.04	5.94	12.82	20.45	59.34
Sweden	0.05	5.37	10.20	15.80	59.10
Switzerland	0.01	10.48	22.02	33.33	63.89
United Kingdom	0.00	2.81	8.29	17.23	42.43

Table A.2.3 – Distribution of the accuracy improvement from today's carbon accounting standards at the weekly time scale. The lower and higher whiskers correspond to the minimum and maximum relative improvement, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distributions.

Country	Accuracy improvement [%]				
	L. Whisker	Q1	Q2	Q3	H. Whisker
Austria	0.01	12.05	19.27	31.78	52.42
Belgium	0.08	9.46	15.70	23.89	40.63
Bulgaria	0.01	3.84	8.05	12.43	32.77
Czechia	0.01	2.56	4.96	7.37	15.83
Denmark	0.27	11.43	19.37	36.39	65.58
Estonia	0.22	7.58	16.32	30.48	61.46
Finland	0.07	8.84	23.46	44.81	64.30
France	0.03	9.12	18.65	36.18	62.71
Germany	0.02	3.81	7.72	11.65	23.56
Greece	0.00	2.07	3.63	5.73	11.15
Hungary	0.02	3.26	6.54	11.50	25.00
Ireland	0.02	3.01	7.44	11.84	22.94
Italy	0.01	2.38	5.04	6.99	17.56
Latvia	0.03	6.55	10.43	16.67	52.81
Lithuania	0.01	5.84	14.09	27.04	77.33
Netherlands	0.00	3.82	7.69	11.27	15.86
Poland	0.00	0.66	1.82	3.50	6.37
Portugal	0.02	5.48	11.57	19.94	48.55
Romania	0.09	5.46	7.89	13.25	31.25
Slovakia	0.00	2.59	6.55	12.06	21.00
Slovenia	0.01	6.99	12.75	27.11	67.17
Spain	0.01	5.26	10.66	15.20	28.18
Sweden	0.05	3.58	6.57	13.73	38.93
Switzerland	0.00	7.73	15.99	25.30	45.71
United Kingdom	0.01	2.77	6.10	12.19	24.19

Table A.2.4 – Distribution of the accuracy improvement from today's carbon accounting standards at the monthly time scale. The lower and higher whiskers correspond to the minimum and maximum relative improvement, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distributions.

A

(Chapter 2)

B

B

(Chapter 3)

C

C.1 Generation and demand data

	Hydro [GWh]		Solar [GWh]	Wind [GWh]	
Country	**Run-of-river**	**Reservoir**	**Photovoltaic**	**Onshore**	**Offshore**
Austria	22068	4032	0	7228	-
Belgium	245	-	3529	3833	5332
Bulgaria	1003	1656	1422	1315	0
Czechia	875	1116	2261	691	-
Denmark	0	-	963	10456	5694
Estonia	18	-	0	688	0
Finland	12284	-	0	5985	0
France	31111	21952	11044	34180	0
Germany	15014	1366	44895	101185	24563
Greece	0	3617	3961	7278	0
Hungary	101	112	1374	705	-
Ireland	878	-	0	9365	0
Italy	21206	23984	24326	20063	0
Latvia	2096	-	0	152	0
Lithuania	340	-	74	1482	0
Netherlands	0	-	5063	5671	5777
Poland	1780	159	0	14703	0
Portugal	5231	1930	1292	13585	0
Romania	10185	5287	1760	6705	0
Slovakia	3935	318	589	3	-
Slovenia	4338	-	268	6	-
Spain	8087	16623	14326	54625	0
Sweden	-	64623	0	19902	0
Switzerland	17735	17260	1963	140	-
United Kingdom	5603	-	12677	35485	28650
Europe	164133	164034	132689	355432	70015

Table C.1.1 – Annual electricity generation [55–58] [GWh] by technology used to validate the hourly generation profiles.

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Country	Hydro [MW]		Solar [MW]	Wind [MW]	
	Run-of-river	Reservoir	Photovoltaic	Onshore	Offshore
Austria	6610	2833	1431	3085	0
Belgium	181	0	3619	2113	1363
Bulgaria	535	1810	1057	700	0
Czechia	334	753	2049	316	0
Denmark	8	0	1014	4426	1700
Estonia	7	0	33	341	0
Finland	3148	0	134	2080	71
France	10955	8279	10100	15108	7
Germany	3950	1298	47100	52212	6900
Greece	299	2403	2523	2754	0
Hungary	29	28	936	326	0
Ireland	216	0	33	3700	25
Italy	10650	4357	20120	10330	0
Latvia	1539	0	1	70	0
Lithuania	120	0	82	530	0
Netherlands	38	0	4522	3669	957
Poland	435	157	640	5878	0
Portugal	2858	1515	828	5157	0
Romania	2760	3573	1157	2970	0
Slovakia	1208	418	531	4	0
Slovenia	1078	0	275	5	0
Spain	6142	12626	8914	25704	10
Sweden	0	16301	501	7853	177
Switzerland	4162	8224	2246	75	0
United Kingdom	2950	0	13400	13619	10328
Europe	60212	64575	123246	163024	21539

Table C.1.2 – Current installed generation capacities [MW] by country.

C

	Hydro [-]		Solar [-]	Wind [-]	
Country	Run-of-river	Reservoir	Photovoltaic	Onshore	Offshore
Austria	0.381	0.162	0.097	0.267	-
Belgium	0.155	-	0.111	0.207	0.447
Bulgaria	0.214	0.104	0.154	0.214	0.448
Czechia	0.299	0.169	0.126	0.250	-
Denmark	0.000	-	0.108	0.270	0.382
Estonia	0.298	-	0.097	0.230	0.448
Finland	0.445	-	0.097	0.328	0.448
France	0.324	0.303	0.125	0.258	0.448
Germany	0.434	0.120	0.109	0.221	0.406
Greece	0.000 *	0.172	0.179	0.302	0.448
Hungary	0.397	0.458	0.100	0.247	-
Ireland	0.464	-	0.097	0.289	0.448
Italy	0.227	0.628	0.138	0.222	0.448
Latvia	0.155	-	0.097	0.247	0.448
Lithuania	0.323	-	0.103	0.319	0.448
Netherlands	0.000 *	-	0.100	0.230	0.520
Poland	0.467	0.115	0.097	0.286	0.448
Portugal	0.209	0.145	0.178	0.301	0.448
Romania	0.421	0.169	0.174	0.258	0.448
Slovakia	0.372	0.100	0.127	0.256	-
Slovenia	0.459	-	0.111	0.149	-
Spain	0.150	0.150	0.183	0.243	0.448
Sweden	-	0.453	0.097	0.289	0.448
Switzerland	0.486	0.240	0.100	0.213	-
United Kingdom	0.217	-	0.108	0.297	0.317
Europe	0.288	0.264	0.118	0.230	0.333

* The generation technology is either not installed or not used at all, although the potential is not null.

Table C.1.3 – Yearly average capacity factors [-] of the generation technologies by country. The factors are validated using the published validity ranges [83].

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	Hydro [MW]		Solar [MW]	Wind [MW]	
Country	**Run-of-river**	**Reservoir**	**Photovoltaic**	**Onshore**	**Offshore**
Austria	6610 *	43565	163242	62000	0
Belgium	181 *	0	97423	13000	5000
Bulgaria	3019	9990	260162	57000	35000
Czechia	573	1221	187591	96000	0
Denmark	8 *	0	141057	83000	220000
Estonia	7 *	0	52511	46000	54000
Finland	3148 *	0	65068	58000	240000
France	10955 *	40730	1612248	944000	331000
Germany	3950 *	22858	940007	308000	106000
Greece	299 *	11960	270696	172000	114000
Hungary	80	1074	155289	98000	0
Ireland	216 *	0	210046	164000	235000
Italy	26517	19474	928832	226000	146000
Latvia	1539 *	0	93607	85000	83000
Lithuania	258	0	177685	142000	21000
Netherlands	38 *	0	108064	49000	97000
Poland	1247	8566	931507	502000	113000
Portugal	3098	18368	169856	43000	57000
Romania	2760 *	20566	552862	183000	80000
Slovakia	1208 *	7237	107282	34000	0
Slovenia	1078 *	0	19198	3000	0
Spain	6142 *	46331	1184747	731000	128000
Sweden	0	30018	134703	192000	403000
Switzerland	4227	10954	76484	16307	0
United Kingdom	4073	0	613099	436000	1040000
Europe	81230	292911	9253265	4743307	3508000

* All potential capacity already installed.

Table C.1.4 – Potential generation capacities [MW] by country.

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Country	Direct electricity [-] Current	Direct electricity [-] Mobility	Heating [-] Households	Heating [-] Services	Demand [GWh]
Austria	0.672	0.179	0.113	0.036	93914
Belgium	0.678	0.141	0.130	0.051	125371
Bulgaria	0.785	0.159	0.042	0.014	47778
Czechia	0.657	0.161	0.134	0.048	100745
Denmark	0.612	0.160	0.178	0.051	54842
Estonia	0.636	0.143	0.169	0.053	12948
Finland	0.774	0.098	0.086	0.041	107814
France	0.719	0.175	0.069	0.037	650589
Germany	0.602	0.192	0.150	0.056	815345
Greece	0.755	0.186	0.051	0.008	68431
Hungary	0.623	0.164	0.158	0.056	69912
Ireland	0.666	0.159	0.136	0.039	43653
Italy	0.651	0.209	0.107	0.033	451866
Latvia	0.547	0.237	0.150	0.066	13222
Lithuania	0.595	0.236	0.120	0.049	20468
Netherlands	0.688	0.125	0.136	0.050	165497
Poland	0.618	0.169	0.175	0.039	273472
Portugal	0.782	0.173	0.037	0.009	64382
Romania	0.684	0.165	0.115	0.036	87848
Slovakia	0.689	0.134	0.126	0.051	42145
Slovenia	0.704	0.215	0.057	0.024	18767
Spain	0.749	0.173	0.055	0.023	333724
Sweden	0.797	0.114	0.062	0.027	171163
Switzerland	0.668	0.163	0.119	0.051	86454
United Kingdom	0.614	0.183	0.163	0.040	485588
Europe	0.670	0.174	0.116	0.040	4405939

Table C.1.5 – Annual electricity demand [GWh] and shares [-] by contribution.

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Country	Cities
Austria	Vienna, Graz, Linz, Innsbruck
Belgium	Gent, Brussels, Bastogne, Antwerpen
Bulgaria	Sofia, Varna, Plovdiv
Czechia	Prague, Pilsen, Brno, Ostrava
Denmark	Copenhagen, Herning, Aalborg
Estonia	Tallinn, Tartu
Finland	Helsinki, Tampere, Oulu, Rovaniemi
France	Paris, Nantes, Toulouse, Marseille, Lyon, Lille, Nancy, Bourges, Calais
Germany	Dusseldorf, Frankfurt, Stuttgart, Munich, Nuremberg, Dresden, Berlin, Magdeburg, Hamburg, Hanover
Greece	Athens, Tripoli, Ioannina, Larissa, Thessaloniki
Hungary	Budapest, Pecs, Miskolc, Szeged
Ireland	Dublin, Cork, Galway
Italy	Cagliari, Palermo, Catania, Bari, Naples, Rome, Ancona, Florence, Bologna, Turin, Milan, Venice
Latvia	Riga, Rezekne
Lithuania	Vilnius, Palanga
Netherlands	Amsterdam, Rotterdam, Groningen, Eindhoven
Poland	Warsaw, Wroclaw, Krakow, Lublin, Szczecin, Gdynia, Bialystok
Portugal	Lisbon, Porto
Romania	Bucharest, Timisoara, Constanta, Iasi
Slovakia	Bratislava, Kosice
Slovenia	Ljubljana, Maribor
Spain	Seville, Madrid, Valencia, Barcelona, Bilbao, Vigo, Salamanca
Sweden	Stockholm, Gothenburg, Ostersund, Umea, Lulea
Switzerland	Geneva, Lausanne, Sion, Zurich, Bern, Davos
United Kingdom	London, Norwich, Birmingham, Exeter, Manchester, Hull, Newcastle, Edinburgh, Belfast, Inverness

Table C.1.6 – Locations (cities) considered to calculate the hourly external temperature profile.

C.2 Data errors

	Simulation residuals [-]				
Country	**L. Whisker**	**Q1**	**Q2**	**Q3**	**H. Whisker**
Austria	0.000	0.003	0.012	0.025	0.043
Belgium	0.000	0.015	0.048	0.090	0.155
Bulgaria	0.000	0.003	0.012	0.023	0.042
Czechia	0.000	0.004	0.017	0.036	0.071
Denmark	0.000	0.004	0.019	0.037	0.066
Estonia	0.000	0.003	0.014	0.030	0.055
Finland	0.000	0.003	0.010	0.020	0.036
France	0.000	0.002	0.008	0.018	0.035
Germany	0.000	0.003	0.013	0.028	0.053
Greece	0.000	0.001	0.008	0.018	0.035
Hungary	0.000	0.005	0.025	0.056	0.116
Ireland	0.000	0.005	0.017	0.032	0.055
Italy	0.000	0.002	0.008	0.017	0.031
Latvia	0.000	0.003	0.016	0.034	0.075
Lithuania	0.000	0.004	0.018	0.036	0.067
Netherlands	0.000	0.006	0.021	0.040	0.074
Poland	0.000	0.003	0.016	0.033	0.063
Portugal	0.000	0.002	0.008	0.017	0.033
Romania	0.000	0.002	0.008	0.017	0.031
Slovakia	0.000	0.002	0.006	0.012	0.021
Slovenia	0.000	0.010	0.032	0.063	0.105
Spain	0.000	0.001	0.006	0.014	0.027
Sweden	0.000	0.001	0.004	0.007	0.014
Switzerland	0.000	0.008	0.025	0.051	0.089
United Kingdom	0.000	0.004	0.014	0.027	0.052
Europe *	0.000	0.003	0.013	0.026	0.049
Europe **	0.000	0.002	0.008	0.015	0.027

* Independent countries with isolated grids.

** Interconnected grids.

Table C.2.1 – Error of the simulation algorithm. Residual of the hourly electricity balance calculated as relative error with respect to the hourly electricity demand. The lower and higher whiskers correspond to the 5- and 95-percentile of the observed residuals, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the error distributions.

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Country	ENTSO-E residuals [-]				
	L. Whisker	Q1	Q2	Q3	H. Whisker
Austria	0.004	0.018	0.037	0.076	0.200
Belgium	0.001	0.003	0.006	0.012	0.050
Bulgaria	0.000	0.002	0.025	0.078	0.166
Czechia	0.001	0.006	0.010	0.032	0.082
Denmark	0.003	0.013	0.029	0.086	0.214
Estonia	0.000	0.002	0.005	0.010	0.028
Finland	0.021	0.033	0.042	0.053	0.064
France	0.001	0.006	0.012	0.020	0.034
Germany	0.003	0.014	0.028	0.043	0.065
Greece	0.002	0.010	0.019	0.028	0.040
Hungary	0.004	0.010	0.013	0.024	0.067
Ireland	0.058	0.127	0.187	0.251	0.326
Italy	0.003	0.006	0.009	0.019	0.046
Latvia	0.000	0.002	0.004	0.007	0.012
Lithuania	0.001	0.008	0.028	0.163	0.651
Netherlands	0.144	0.184	0.211	0.245	0.303
Poland	0.045	0.071	0.082	0.089	0.097
Portugal	0.000	0.001	0.010	0.082	0.229
Romania	0.000	0.000	0.001	0.001	0.003
Slovakia	0.002	0.010	0.024	0.051	0.106
Slovenia	0.052	0.076	0.107	0.167	0.248
Spain	0.000	0.002	0.005	0.012	0.021
Sweden	0.004	0.018	0.030	0.042	0.065
Switzerland	0.009	0.046	0.103	0.187	0.336
United Kingdom	0.010	0.043	0.074	0.111	0.167
Europe *	0.012	0.026	0.039	0.058	0.095

* Independent countries with isolated grids.

Table C.2.2 – Relative error of the ENTSO-E data. Residuals of the hourly electricity balance calculated as relative error with respect to the hourly electricity demand. The lower and higher whiskers correspond to the 5- and 95-percentile of the observed residuals, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the error distributions.

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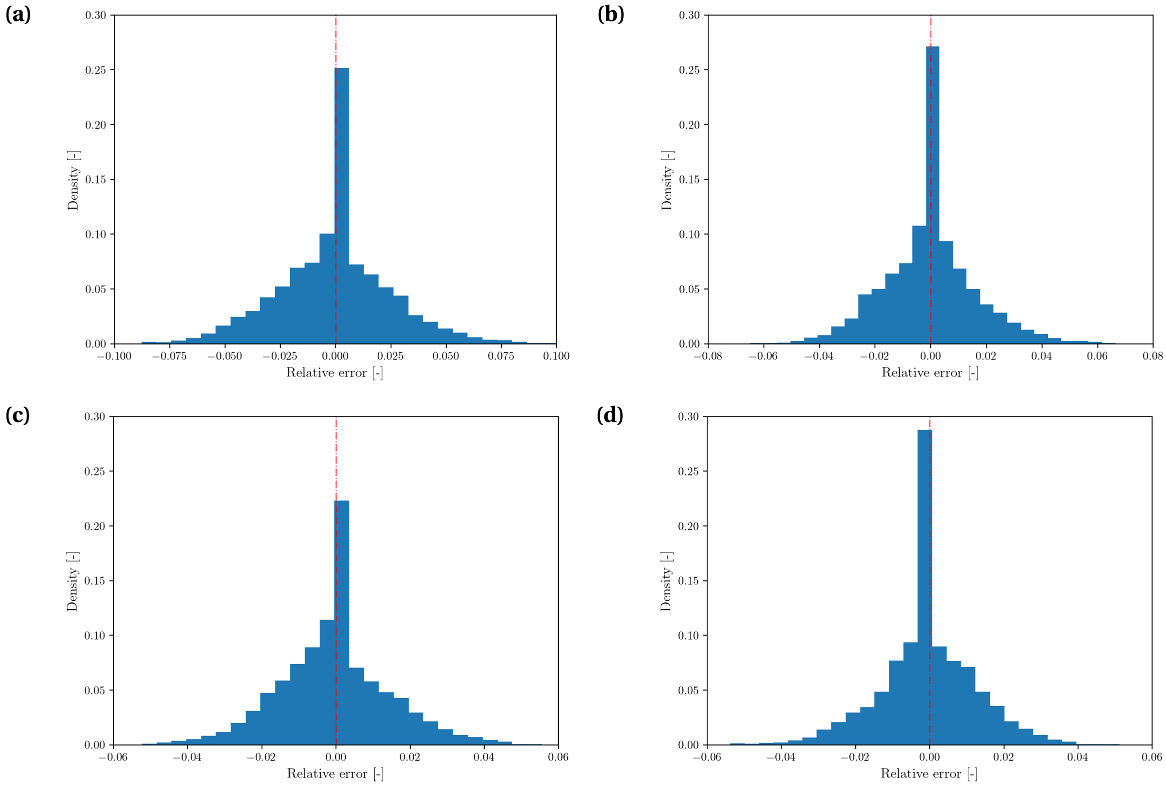

Figure C.2.1 – Error distributions of the simulation algorithm for **(a)**, Germany **(b)**, France **(c)**, Italy **(d)** Spain. Residuals of the hourly electricity balance calculated as relative error [-] with respect to the hourly electricity demand.

C.3 Cost data

		Hydro		Solar	Wind	
Type	**Sub-type**	**Run-of-river**	**Reservoir**	**Photovoltaic**	**Onshore**	**Offshore**
Capital	fixed [1]	2250.00	1852.00	934.00	1743.50	3947.00
Maintenance	fixed [2]	18.00	19.93	46.70	33.36	118.41
	variable [3]	0.95	2.46	-	8.46	-

[1] USD per kW of installed capacity.
[2] USD/year per kW of installed capacity.
[3] USD/year per MWh of annual produced electricity.

Table C.3.1 – Capital (fixed) and maintenance (fixed and variable) costs of the electricity generation technologies. The values correspond to the medians of the empirical distributions obtained from the reviewed literature.

Type	Sub-type	Battery				Power-to-gas	
		Lead-acid	Lithium-ion	Vanadium flow	Zinc flow	SNG	Hydrogen
Capital	fixed	250.00 [1]	377.50 [1]	403.00 [1]	492.50 [1]	-	-
	variable	-	-	-	-	0.0695 [2]	0.1790 [2]
Maintenance	fixed	9.93 [3]	15.00 [3]	16.01 [3]	19.57 [3]	-	-
	variable	0.13 [4]	0.20 [4]	0.21 [4]	0.26 [4]	0.0034 [5]	0.0089 [5]

[1] USD per kWh of installed capacity.
[2] USD per kWh of produced gas.
[3] USD/year per kW of installed peak power.
[4] USD/year per MWh of annual discharged electricity.
[5] USD/year per kWh of annual produced gas.

Table C.3.2 – Capital (fixed and variable) and maintenance (fixed and variable) costs of storage. The values correspond to the medians of the empirical distributions obtained from the reviewed literature.

C.4 Environmental impact factors

Storage	Technology	Distribution	min	median	max	Parameters				p-value
						p1	p2	p3	p4	
Battery	Lead-acid	Beta	78.00	115.00	178.00	0.633	0.750	78.00	106.69	0.962
	Lithium-ion	Uniform	18.00	54.70	61.00	-	-	-	-	-
	Vanadium flow	GEV	11.70	15.49	42.00	-0.567	14.389	3.187	-	0.695
	Zinc flow	Uniform	9.19	11.54	31.03	-	-	-	-	-
PtoG	SNG	-	-	150.60	-	-	-	-	-	-
	Hydrogen	-	-	115.80	-	-	-	-	-	-

Table C.4.1 – Probability distributions used to draw the Global Warming Potential (GWP100a) [gCO_2eq/kWh] associated with storage. The distributions are identified using the Kolmogorov-Smirnov test. Not enough data are available from the reviewed literature for the power-to-gas, hence the impact factors associated with the long-term storage are assumed deterministic.

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Country	RE share [-]		IPCC 2013 climate change [gCO_2eq/kWh]		Ecological scarcity [UBP/kWh]	Ecological footprint [m2a/kWh]
	Method 1 [1]	Method 2 [2]	GWP100a	GWP20a	Total	Total
Austria	0.69	0.61	271.06	307.84	231.03	0.960
Belgium	0.19	0.17	214.74	236.92	313.36	2.003
Bulgaria	0.16	0.14	553.14	571.78	616.11	2.430
Czechia	0.16	0.12	763.49	803.29	657.05	2.968
Denmark	0.71	0.66	207.00	233.94	223.83	1.068
Estonia	0.32	0.31	582.98	608.25	616.39	2.214
Finland	0.42	0.41	191.70	214.69	286.69	1.801
France	0.21	0.19	73.08	80.77	316.34	2.173
Germany	0.44	0.34	443.35	495.82	374.33	1.551
Greece	0.30	0.27	666.00	741.38	579.19	1.758
Hungary	0.19	0.17	380.39	426.22	425.99	2.219
Ireland	0.42	0.39	377.42	396.39	329.66	1.023
Italy	0.37	0.32	382.87	445.01	301.06	1.167
Latvia	0.42	0.38	413.12	454.70	360.39	1.436
Lithuania	0.61	0.55	227.87	254.28	268.96	1.290
Netherlands	0.16	0.15	540.51	596.37	377.79	1.627
Poland	0.16	0.15	947.36	1038.82	782.91	2.531
Portugal	0.53	0.48	299.23	334.80	257.53	1.026
Romania	0.40	0.38	402.25	421.47	819.53	1.689
Slovakia	0.21	0.19	399.63	434.85	487.04	2.358
Slovenia	0.43	0.39	347.35	365.04	448.15	1.691
Spain	0.40	0.37	232.51	255.31	263.58	1.314
Sweden	0.55	0.54	37.44	43.94	181.29	1.300
Switzerland	0.45	0.34	175.59	194.57	313.62	1.805
United Kingdom	0.30	0.28	270.80	286.42	297.84	1.557
Europe	0.34	0.29	337.24	372.31	368.44	1.714

[1] Assume 100% renewable energy use.

[2] Calculated from the real cumulative energy demand [41].

Table C.4.2 – Environmental impact indicators of the current electricity grid by country and all Europe. The impacts reported in this table are calculated weighting the hourly values by the corresponding hourly electricity demands.

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	Electricity	Fossil fuels	Heating		
Country	**Grid**	**Mobility**	**Households**	**Services**	**Total**
Austria	271.06	243.84	113.50	113.50	207.57
Belgium	214.74	250.80	218.83	218.83	228.31
Bulgaria	553.14	249.23	65.59	65.59	321.88
Czechia	763.49	247.43	136.35	136.35	345.21
Denmark	207.00	259.31	46.67	46.67	155.56
Estonia	582.98	249.30	34.55	34.55	242.31
Finland	191.70	234.34	31.03	31.03	147.33
France	73.08	250.63	145.86	145.86	158.58
Germany	443.35	251.73	162.69	162.69	264.36
Greece	666.00	253.23	146.60	146.60	360.65
Hungary	380.39	249.64	141.08	141.08	234.65
Ireland	377.42	254.28	256.41	256.41	286.78
Italy	382.87	250.21	161.38	161.38	246.13
Latvia	413.12	259.55	49.35	49.35	186.66
Lithuania	227.87	254.28	66.84	66.84	180.28
Netherlands	540.51	248.24	188.71	188.71	310.38
Poland	947.36	251.52	195.82	195.82	397.45
Portugal	299.23	254.07	100.75	100.75	231.32
Romania	402.25	251.33	101.71	101.71	227.37
Slovakia	399.63	248.82	158.80	158.80	266.64
Slovenia	347.35	254.86	84.05	84.05	235.62
Spain	232.51	247.69	157.66	157.66	222.20
Sweden	37.44	189.88	13.86	13.86	74.93
Switzerland	175.59	224.29	157.40	157.40	184.31
United Kingdom	270.80	246.07	200.48	200.48	233.96
Europe	337.24	247.97	157.24	157.24	239.90

Table C.4.3 – Sector-specific and total Global Warming Potentials (IPCC 2013 climate change GWP100a) of the current energy system by country and all Europe. The indicator is measured in grams of CO_2 equivalent emitted per kWh of consumed energy [gCO_2eq/kWh].

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C.5 Electricity generation and demand results

	Hydro [-]		Solar [-]	Wind [-]	
Country	Run-of-river	Reservoir	Photovoltaic	Onshore	Offshore
Austria	0.193	0.494	0.012	0.302	-
Belgium	0.001	-	0.762	0.132	0.105
Bulgaria	0.098	0.033	0.178	0.216	0.476
Czechia	0.010	0.010	0.047	0.934	-
Denmark	0.000	-	0.067	0.556	0.376
Estonia	0.001	-	0.002	0.648	0.348
Finland	0.095	-	0.001	0.406	0.498
France	0.040	0.118	0.072	0.217	0.553
Germany	0.014	0.019	0.120	0.488	0.358
Greece	0.000	0.186	0.120	0.520	0.174
Hungary	0.003	0.035	0.102	0.860	-
Ireland	0.015	-	0.009	0.804	0.171
Italy	0.103	0.117	0.128	0.289	0.363
Latvia	0.122	-	0.054	0.612	0.212
Lithuania	0.027	-	0.042	0.719	0.212
Netherlands	0.000	-	0.033	0.050	0.917
Poland	0.014	0.006	0.006	0.814	0.159
Portugal	0.073	0.076	0.061	0.445	0.345
Romania	0.100	0.213	0.089	0.297	0.301
Slovakia	0.083	0.036	0.028	0.853	-
Slovenia	0.181	-	0.652	0.167	-
Spain	0.021	0.090	0.095	0.585	0.209
Sweden	-	0.637	0.004	0.223	0.136
Switzerland	0.155	0.197	0.447	0.201	-
United Kingdom	0.010	-	0.100	0.699	0.191
Europe *	0.053	0.087	0.133	0.486	0.242
Europe **	0.038	0.142	0.068	0.526	0.227

* Independent countries with isolated grids.
** Interconnected grids.

Table C.5.1 – Electricity production shares [-] of the best observed solutions. Results *without curtailment.*

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Country	Hydro [-] Run-of-river	Hydro [-] Reservoir	Solar [-] Photovoltaic	Wind [-] Onshore	Wind [-] Offshore	Generation [GWh]
Austria	0.235	0.602	0.015	0.368	0.000	114476
Belgium	0.002	0.000	1.137	0.196	0.156	186986
Bulgaria	0.114	0.038	0.208	0.251	0.555	55674
Czechia	0.014	0.013	0.063	1.262	0.000	136123
Denmark	0.000	0.000	0.090	0.742	0.502	73163
Estonia	0.001	0.000	0.003	0.814	0.437	16258
Finland	0.114	0.000	0.001	0.484	0.594	128655
France	0.048	0.143	0.087	0.262	0.666	783599
Germany	0.018	0.025	0.153	0.620	0.455	1035600
Greece	0.000	0.218	0.141	0.609	0.204	80209
Hungary	0.004	0.050	0.147	1.241	0.000	100859
Ireland	0.020	0.000	0.012	1.068	0.228	57967
Italy	0.118	0.134	0.147	0.331	0.415	517089
Latvia	0.159	0.000	0.070	0.796	0.276	17192
Lithuania	0.035	0.000	0.054	0.919	0.271	26166
Netherlands	0.000	0.000	0.046	0.070	1.269	229118
Poland	0.019	0.008	0.008	1.070	0.209	359328
Portugal	0.086	0.089	0.072	0.526	0.408	76071
Romania	0.116	0.247	0.103	0.343	0.348	101583
Slovakia	0.093	0.040	0.032	0.960	0.000	47447
Slovenia	0.231	0.000	0.835	0.214	0.000	24026
Spain	0.024	0.105	0.110	0.682	0.243	389094
Sweden	0.000	0.683	0.004	0.238	0.146	183404
Switzerland	0.209	0.266	0.603	0.271	0.000	116516
United Kingdom	0.012	0.000	0.126	0.881	0.240	612025
Europe	0.043	0.161	0.077	0.596	0.258	4996038

Table C.5.2 – Electricity production, as fraction [-] of the demand, and annual generation [GWh] for the best observed solutions by country. Results *without curtailment*.

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Country	Hydro [MW] Run-of-river	Hydro [MW] Reservoir	Solar [MW] Photovoltaic	Wind [MW] Onshore	Wind [MW] Offshore	Total [MW]
Austria	6608	39703	1646	14732	-	62689
Belgium	181	-	146194	13573	5000	164949
Bulgaria	2900	1978	7373	6390	6751	25391
Czechia	525	878	5745	58127	-	65275
Denmark	0	-	5180	17227	8224	30631
Estonia	7	-	42	5225	1442	6715
Finland	3148	-	146	18149	16307	37750
France	10956	34983	51577	75257	110301	283074
Germany	3950	19101	130462	260772	104153	518438
Greece	0	9925	6138	15770	3554	35388
Hungary	84	877	11725	40112	-	52797
Ireland	216	-	617	18424	2531	21788
Italy	26811	10968	54853	76959	47765	217356
Latvia	1539	-	1099	4870	928	8436
Lithuania	251	-	1213	6730	1412	9606
Netherlands	0	-	8602	5734	46108	60444
Poland	1246	2208	2712	116946	14565	137676
Portugal	3030	4516	2958	12863	6691	30058
Romania	2760	14636	5938	13364	7778	44476
Slovakia	1207	1940	1212	18042	-	22400
Slovenia	1078	-	16067	3089	-	20233
Spain	6142	26724	22933	107161	20690	183651
Sweden	-	29479	906	16103	6358	52845
Switzerland	4230	10962	59610	12533	-	87335
United Kingdom	3081	-	64916	164280	42080	274357
Europe *	79950	208877	609862	1102432	452639	2453762
Europe **	74492	305940	327363	1304061	388474	2400330

* Independent countries with isolated grids.

** Interconnected grids.

Table C.5.3 – Installed generation capacities [MW] for the best observed solution. Results *without curtailment.*

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	Hydro [-]		Solar [-]	Wind [-]	
Country	**Run-of-river**	**Reservoir**	**Photovoltaic**	**Onshore**	**Offshore**
Austria	0.662	0.121	0.000	0.217	-
Belgium	0.019	-	0.273	0.296	0.412
Bulgaria	0.186	0.307	0.264	0.244	0.000
Czechia	0.177	0.226	0.457	0.140	-
Denmark	0.000	-	0.056	0.611	0.333
Estonia	0.026	-	0.000	0.974	0.000
Finland	0.672	-	0.000	0.328	0.000
France	0.317	0.223	0.112	0.348	0.000
Germany	0.080	0.007	0.240	0.541	0.131
Greece	0.000	0.243	0.267	0.490	0.000
Hungary	0.044	0.049	0.599	0.308	-
Ireland	0.086	-	0.000	0.914	0.000
Italy	0.237	0.268	0.272	0.224	0.000
Latvia	0.932	-	0.000	0.068	0.000
Lithuania	0.179	-	0.039	0.781	0.000
Netherlands	0.000	-	0.307	0.343	0.350
Poland	0.107	0.010	0.000	0.884	0.000
Portugal	0.237	0.088	0.059	0.616	0.000
Romania	0.426	0.221	0.074	0.280	0.000
Slovakia	0.812	0.066	0.122	0.001	-
Slovenia	0.941	-	0.058	0.001	-
Spain	0.086	0.177	0.153	0.583	0.000
Sweden	-	0.765	0.000	0.235	0.000
Switzerland	0.478	0.465	0.053	0.004	-
United Kingdom	0.068	-	0.154	0.431	0.348
Europe	0.187	0.184	0.156	0.396	0.077

Table C.5.4 – Current resource shares [-] of renewable generation by country and all Europe.

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	Hydro [EUR/MWh]		Solar [EUR/MWh]	Wind [EUR/MWh]	
Country	**Run-of-river**	**Reservoir**	**Photovoltaic**	**Onshore**	**Offshore**
Austria	57.07	102.47	130.15	75.82	-
Belgium	139.62	-	112.83	95.91	102.39
Bulgaria	101.03	158.14	81.78	92.86	102.02
Czechia	72.53	98.48	99.70	80.74	-
Denmark	-	-	115.81	75.25	119.59
Estonia	72.67	-	130.15	86.92	102.02
Finland	48.94	-	130.15	63.02	102.02
France	66.96	56.04	100.61	78.28	102.02
Germany	50.22	137.81	115.42	90.22	112.52
Greece	-	97.02	70.08	68.00	102.02
Hungary	54.85	37.78	125.59	81.54	-
Ireland	47.04	-	130.15	70.70	102.02
Italy	95.16	28.16	91.00	90.04	102.02
Latvia	138.78	-	130.15	81.64	102.02
Lithuania	67.12	-	121.42	64.67	102.02
Netherlands	-	-	125.59	87.05	87.93
Poland	46.71	143.49	130.15	71.46	102.02
Portugal	103.46	114.21	70.52	68.20	102.02
Romania	51.70	98.64	72.33	78.43	102.02
Slovakia	58.47	165.07	99.19	78.89	-
Slovenia	47.48	-	112.83	130.92	-
Spain	143.52	110.58	68.46	82.88	102.02
Sweden	-	38.23	130.15	70.61	102.02
Switzerland	44.88	70.21	125.91	93.41	-
United Kingdom	99.73	-	116.30	68.87	144.40
Europe	75.39	63.89	106.46	87.05	137.12

Table C.5.5 – Levelized Cost of Electricity (LCOE) [EUR/MWh] of each generation technology by country and all of Europe. Results *without curtailment*.

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	Solar [-]			Wind [-]			Combined [-]		
Country	**Hourly**	**Daily**	**Seasonal**	**Hourly**	**Daily**	**Seasonal**	**Hourly**	**Daily**	**Seasonal**
Austria	-	-	-	0.068	0.189	0.300	-	-	-
Belgium	0.107	0.132	0.468	0.057	0.171	0.293	0.077	0.153	0.097
Bulgaria	0.124	0.150	0.330	0.061	0.144	0.215	0.081	0.140	0.097
Czechia	0.107	0.140	0.418	0.068	0.143	0.349	0.067	0.120	0.302
Denmark	0.097	0.126	0.516	0.059	0.185	0.196	0.063	0.183	0.153
Estonia	-	-	-	0.073	0.176	0.225	-	-	-
Finland	-	-	-	0.062	0.163	0.139	-	-	-
France	0.135	0.093	0.388	0.057	0.131	0.323	0.077	0.126	0.164
Germany	0.108	0.095	0.466	0.051	0.132	0.313	0.084	0.122	0.118
Greece	0.147	0.119	0.290	0.056	0.158	0.271	0.096	0.129	0.204
Hungary	0.029	0.046	0.358	0.052	0.176	0.330	0.021	0.070	0.370
Ireland	-	-	-	0.064	0.188	0.246	-	-	-
Italy	0.146	0.097	0.340	0.065	0.157	0.289	0.083	0.114	0.086
Latvia	-	-	-	0.065	0.173	0.215	-	-	-
Lithuania	0.121	0.089	0.547	0.070	0.177	0.262	0.072	0.176	0.224
Netherlands	0.017	0.040	0.397	0.061	0.182	0.288	0.013	0.084	0.362
Poland	-	-	-	0.064	0.143	0.274	-	-	-
Portugal	0.152	0.117	0.261	0.063	0.156	0.245	0.066	0.152	0.210
Romania	0.125	0.119	0.356	0.066	0.166	0.239	0.078	0.162	0.130
Slovakia	0.122	0.117	0.388	0.004	0.010	0.349	0.073	0.117	0.384
Slovenia	0.037	0.136	0.382	0.048	0.074	0.199	0.023	0.136	0.374
Spain	0.153	0.094	0.316	0.055	0.118	0.226	0.067	0.111	0.128
Sweden	-	-	-	0.041	0.114	0.181	-	-	-
Switzerland	0.110	0.134	0.450	0.053	0.150	0.258	0.068	0.130	0.419
United Kingdom	0.101	0.120	0.449	0.091	0.147	0.203	0.107	0.144	0.089
Europe *	0.119	0.099	0.403	0.061	0.142	0.263	0.078	0.129	0.144
Europe **	0.089	0.095	0.348	0.051	0.083	0.241	0.076	0.078	0.107

* Independent countries with isolated grids.

** Interconnected grids.

Table C.5.6 – Hourly, daily and seasonal variability of solar, wind (onshore and offshore) and combined solar + wind generation by country and all Europe. The variability is calculated using the inter -hours, -days, and -seasons load ramps as share [-] of peak loads.

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Country	Current electricity[-]			Households heating [-]			Services heating [-]			Electrical mobility [-]		
	Hourly	Daily	Seasonal	Hourly	Daily	Seasonal	Hourly	Daily	Seasonal	Hourly	Daily	Seasonal
Austria	0.165	0.057	0.093	0.022	0.040	0.439	0.020	0.041	0.479	0.181	0.070	0.036
Belgium	0.156	0.042	0.076	0.025	0.042	0.463	0.024	0.044	0.514	0.181	0.070	0.036
Bulgaria	0.124	0.023	0.103	0.026	0.033	0.382	0.021	0.035	0.447	0.180	0.080	0.036
Czechia	0.159	0.045	0.099	0.033	0.041	0.406	0.029	0.044	0.476	0.181	0.070	0.036
Denmark	0.069	0.042	0.088	0.031	0.039	0.346	0.025	0.046	0.478	0.181	0.070	0.036
Estonia	0.148	0.037	0.153	0.016	0.033	0.397	0.013	0.035	0.471	0.180	0.080	0.036
Finland	0.142	0.024	0.153	0.016	0.033	0.388	0.014	0.035	0.470	0.180	0.080	0.036
France	0.177	0.036	0.162	0.026	0.039	0.437	0.024	0.040	0.484	0.181	0.070	0.036
Germany	0.170	0.064	0.058	0.031	0.038	0.425	0.027	0.040	0.488	0.181	0.070	0.036
Greece	0.124	0.033	0.157	0.009	0.022	0.361	0.009	0.022	0.367	0.180	0.080	0.036
Hungary	0.166	0.043	0.046	0.022	0.035	0.426	0.021	0.036	0.459	0.181	0.070	0.036
Ireland	0.127	0.033	0.083	0.039	0.054	0.422	0.034	0.062	0.586	0.182	0.074	0.036
Italy	0.154	0.068	0.084	0.023	0.027	0.363	0.020	0.029	0.401	0.181	0.070	0.036
Latvia	0.124	0.040	0.087	0.027	0.044	0.375	0.023	0.049	0.463	0.180	0.080	0.036
Lithuania	0.171	0.039	0.078	0.032	0.038	0.421	0.029	0.040	0.467	0.180	0.080	0.036
Netherlands	0.135	0.045	0.073	0.023	0.040	0.408	0.020	0.043	0.510	0.181	0.070	0.036
Poland	0.163	0.060	0.060	0.028	0.044	0.405	0.024	0.046	0.471	0.181	0.070	0.036
Portugal	0.127	0.051	0.055	0.100	0.023	0.118	0.019	0.038	0.428	0.182	0.074	0.036
Romania	0.168	0.043	0.059	0.025	0.029	0.390	0.021	0.030	0.440	0.180	0.080	0.036
Slovakia	0.062	0.038	0.074	0.029	0.037	0.429	0.027	0.038	0.472	0.181	0.070	0.036
Slovenia	0.090	0.054	0.056	0.030	0.038	0.409	0.027	0.040	0.459	0.181	0.070	0.036
Spain	0.165	0.049	0.059	0.032	0.030	0.334	0.021	0.034	0.467	0.181	0.070	0.036
Sweden	0.117	0.031	0.190	0.027	0.047	0.411	0.023	0.052	0.491	0.181	0.070	0.036
Switzerland	0.079	0.034	0.107	0.032	0.047	0.434	0.030	0.050	0.479	0.181	0.070	0.036
United Kingdom	0.082	0.038	0.116	0.029	0.044	0.414	0.025	0.048	0.541	0.182	0.074	0.036
Europe *	0.147	0.047	0.099	0.028	0.039	0.408	0.024	0.041	0.483	0.181	0.071	0.036
Europe **	0.132	0.044	0.080	0.026	0.028	0.401	0.021	0.030	0.479	0.172	0.071	0.036

* Independent countries with isolated grids.

** Interconnected grids.

Table C.5.7 – Hourly, daily and seasonal variability of current (electricity consumption), households, services and mobility demands by country and all Europe. The variability is calculated using the inter -hours, -days, and -seasons load ramps as share [-] of peak loads.

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C.6 Electricity storage results

	No curtailment		Curtailment	
Country	**Battery [-]**	**Power-to-gas [-]**	**Battery [-]**	**Power-to-gas [-]**
Austria	0.00073	0.134	0.00076	0.095
Belgium	0.00262	0.245	0.00226	0.237
Bulgaria	0.00076	0.045	0.00070	0.034
Czechia	0.00165	0.062	0.00120	0.046
Denmark	0.00155	0.049	0.00153	0.048
Estonia	0.00130	0.052	0.00106	0.054
Finland	0.00076	0.048	0.00068	0.043
France	0.00076	0.055	0.00079	0.053
Germany	0.00096	0.061	0.00097	0.059
Greece	0.00078	0.034	0.00054	0.029
Hungary	0.00263	0.078	0.00180	0.080
Ireland	0.00136	0.076	0.00109	0.063
Italy	0.00051	0.047	0.00044	0.037
Latvia	0.00187	0.061	0.00110	0.054
Lithuania	0.00137	0.046	0.00122	0.042
Netherlands	0.00165	0.059	0.00156	0.056
Poland	0.00133	0.050	0.00108	0.041
Portugal	0.00064	0.073	0.00057	0.058
Romania	0.00066	0.078	0.00074	0.071
Slovakia	0.00038	0.043	0.00031	0.036
Slovenia	0.00171	0.129	0.00180	0.122
Spain	0.00065	0.052	0.00047	0.040
Sweden	0.00022	0.032	0.00021	0.027
Switzerland	0.00134	0.204	0.00099	0.191
United Kingdom	0.00117	0.061	0.00091	0.054
Europe *	0.00099	0.066	0.00087	0.059
Europe **	0.00048	0.036	0.00040	0.034

* Independent countries with isolated grids.

** Interconnected grids.

Table C.6.1 – Storage capacity as fraction [-] of the annual electricity demand by country. Results for the best observed solutions *with* and *without curtailment*.

	No curtailment		Curtailment	
Country	**Battery [%]**	**Power-to-gas [%]**	**Battery [%]**	**Power-to-gas [%]**
Austria	48.26	65.48	50.91	72.05
Belgium	38.08	68.77	38.26	69.04
Bulgaria	47.32	69.86	57.20	72.60
Czechia	44.58	57.81	55.54	65.75
Denmark	48.45	63.29	49.04	63.29
Estonia	45.68	61.10	46.15	64.93
Finland	45.82	67.12	46.94	68.22
France	48.62	64.11	45.99	63.01
Germany	48.93	63.84	50.90	64.66
Greece	50.02	61.64	52.20	65.21
Hungary	46.26	56.99	52.52	65.48
Ireland	48.08	61.37	56.36	63.29
Italy	50.47	70.14	59.75	72.88
Latvia	47.18	60.82	49.10	63.01
Lithuania	46.46	61.92	49.16	65.48
Netherlands	49.53	63.29	53.68	63.56
Poland	45.79	60.55	45.67	65.75
Portugal	47.45	61.92	56.45	66.85
Romania	49.77	69.86	52.39	70.68
Slovakia	46.22	69.04	57.13	72.60
Slovenia	37.79	68.49	37.67	70.14
Spain	47.99	61.37	57.03	66.03
Sweden	49.94	75.62	52.15	77.53
Switzerland	40.92	69.32	44.73	70.14
United Kingdom	49.50	67.12	59.91	70.68
Europe	46.43	67.12	48.63	69.86

Table C.6.2 – Storage charging time [%] as percentage of the annual operating time. Results for the best observed solutions *with* and *without curtailment*.

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Country	No curtailment		Curtailment	
	Battery [-]	Power-to-gas [-]	Battery [-]	Power-to-gas [-]
Austria	0.107	0.283	0.074	0.199
Belgium	0.590	0.476	0.580	0.463
Bulgaria	0.113	0.199	0.076	0.168
Czechia	0.172	0.454	0.126	0.361
Denmark	0.173	0.428	0.169	0.425
Estonia	0.140	0.324	0.113	0.292
Finland	0.092	0.251	0.078	0.232
France	0.079	0.274	0.075	0.268
Germany	0.122	0.354	0.121	0.352
Greece	0.079	0.225	0.062	0.187
Hungary	0.263	0.551	0.218	0.412
Ireland	0.147	0.430	0.118	0.378
Italy	0.074	0.185	0.056	0.167
Latvia	0.169	0.378	0.107	0.301
Lithuania	0.170	0.345	0.140	0.301
Netherlands	0.175	0.503	0.164	0.492
Poland	0.156	0.405	0.127	0.354
Portugal	0.083	0.237	0.066	0.197
Romania	0.079	0.201	0.078	0.184
Slovakia	0.057	0.165	0.043	0.143
Slovenia	0.434	0.250	0.454	0.278
Spain	0.066	0.221	0.052	0.186
Sweden	0.034	0.093	0.025	0.084
Switzerland	0.303	0.389	0.207	0.325
United Kingdom	0.130	0.335	0.090	0.279
Europe	0.073	0.170	0.061	0.152

Table C.6.3 – Total electrical energy sent to storage as fraction [-] of the electricity demand. Results for the best observed solutions *with* and *without curtailment.*

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C.7 Country profiles results

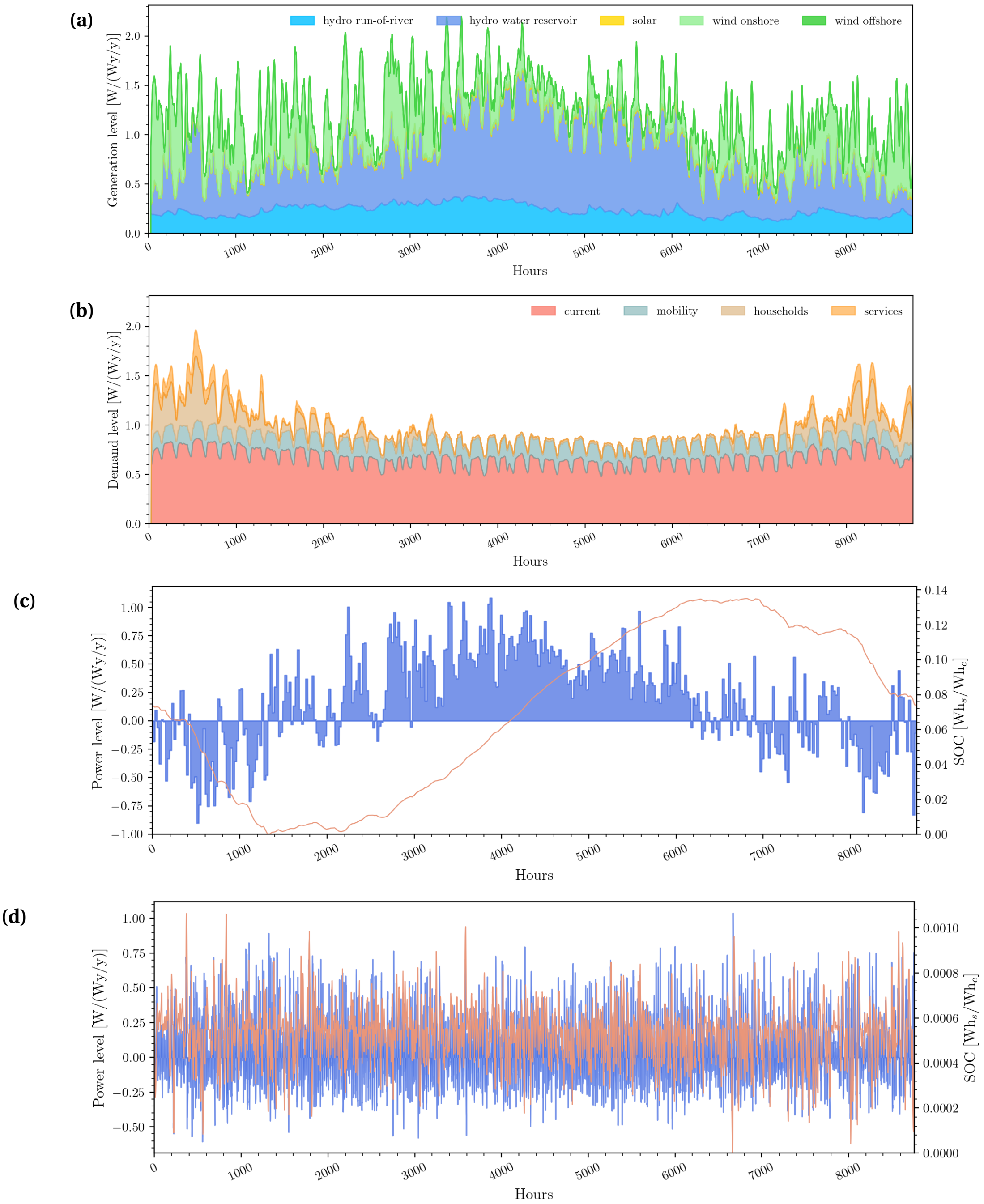

Figure C.7.1 – Hourly electricity production **(a)** and demand **(b)** profiles for *Austria*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

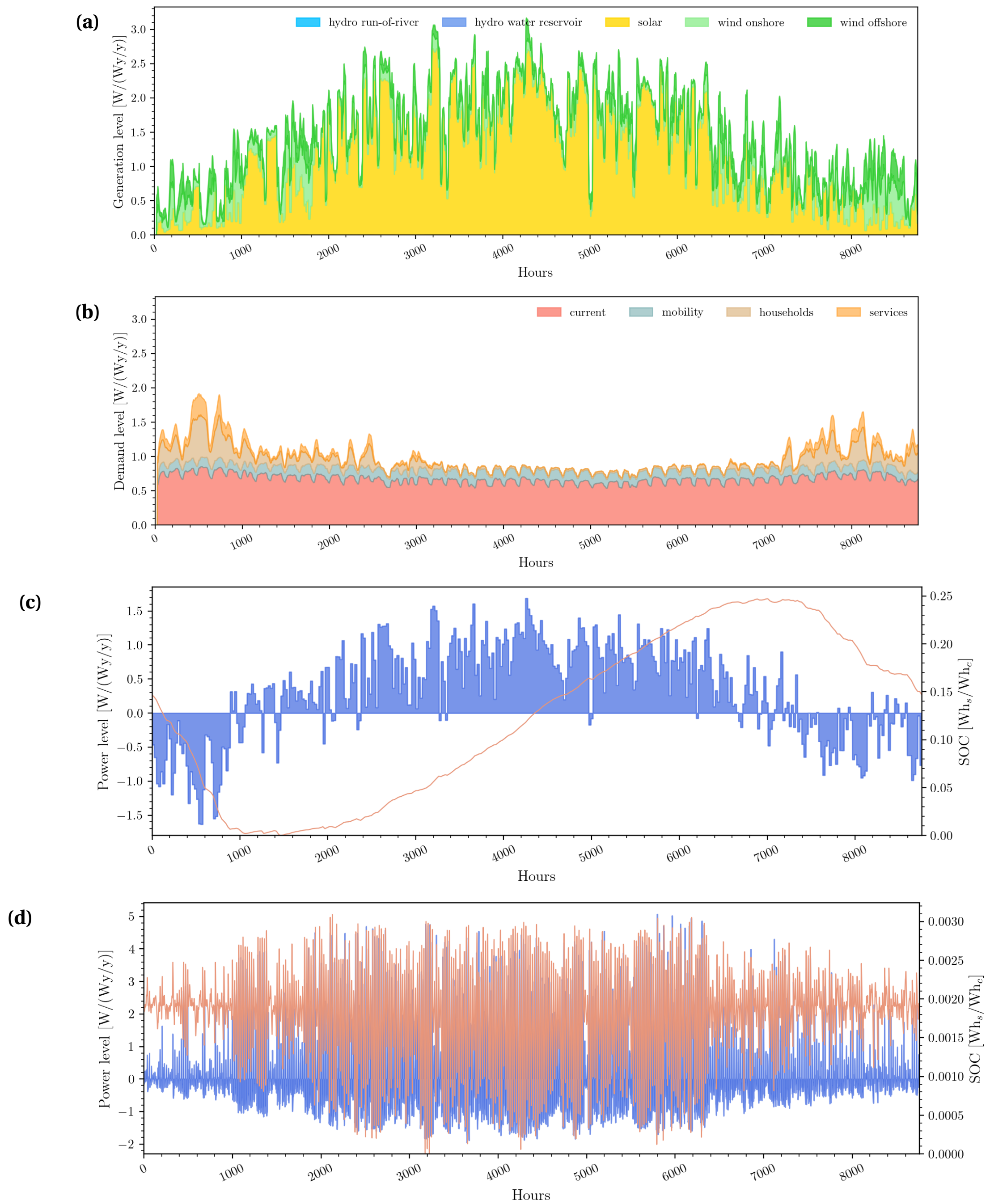

Figure C.7.2 – Hourly electricity production **(a)** and demand **(b)** profiles for *Belgium*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

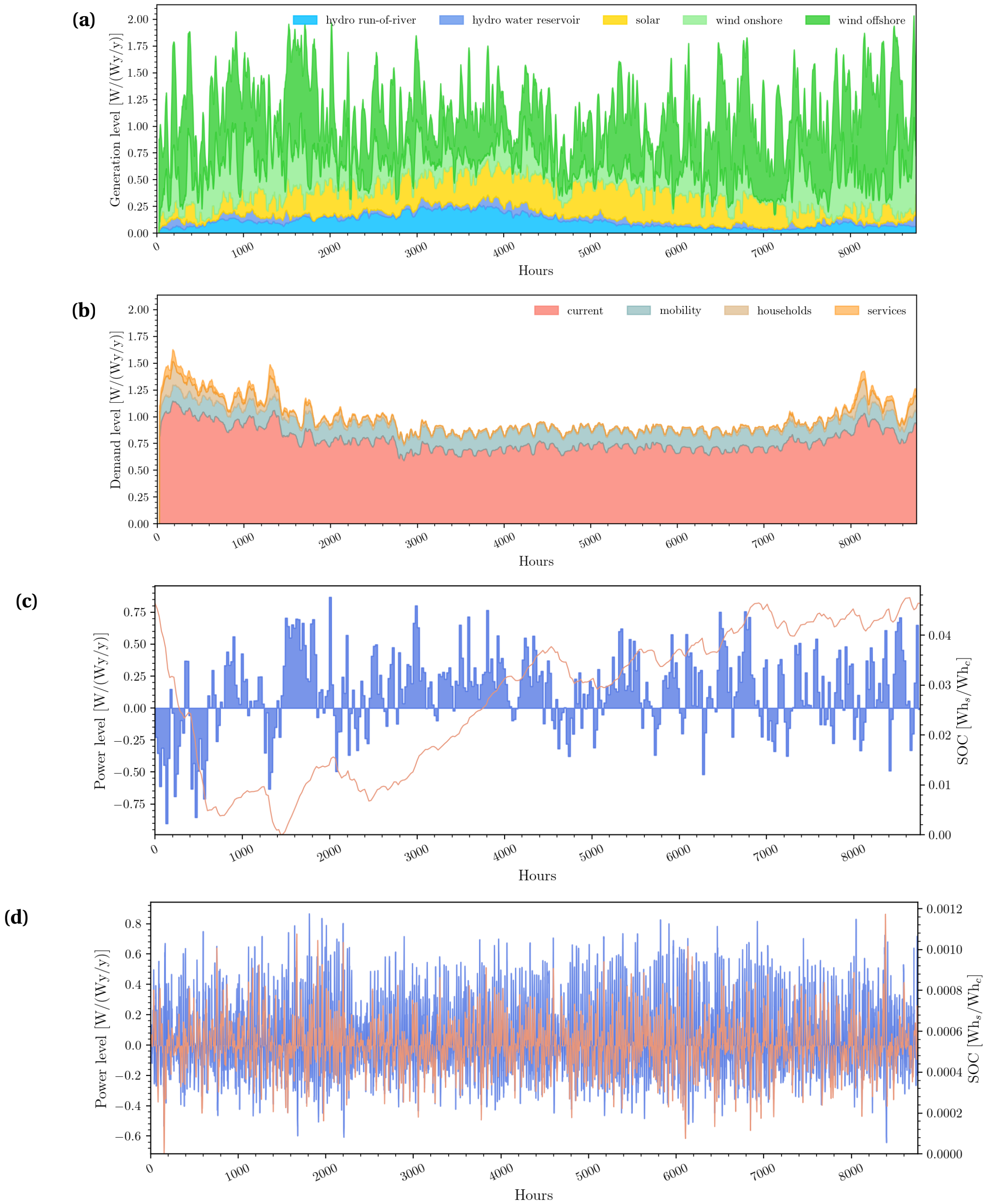

Figure C.7.3 – Hourly electricity production **(a)** and demand **(b)** profiles for *Bulgaria*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

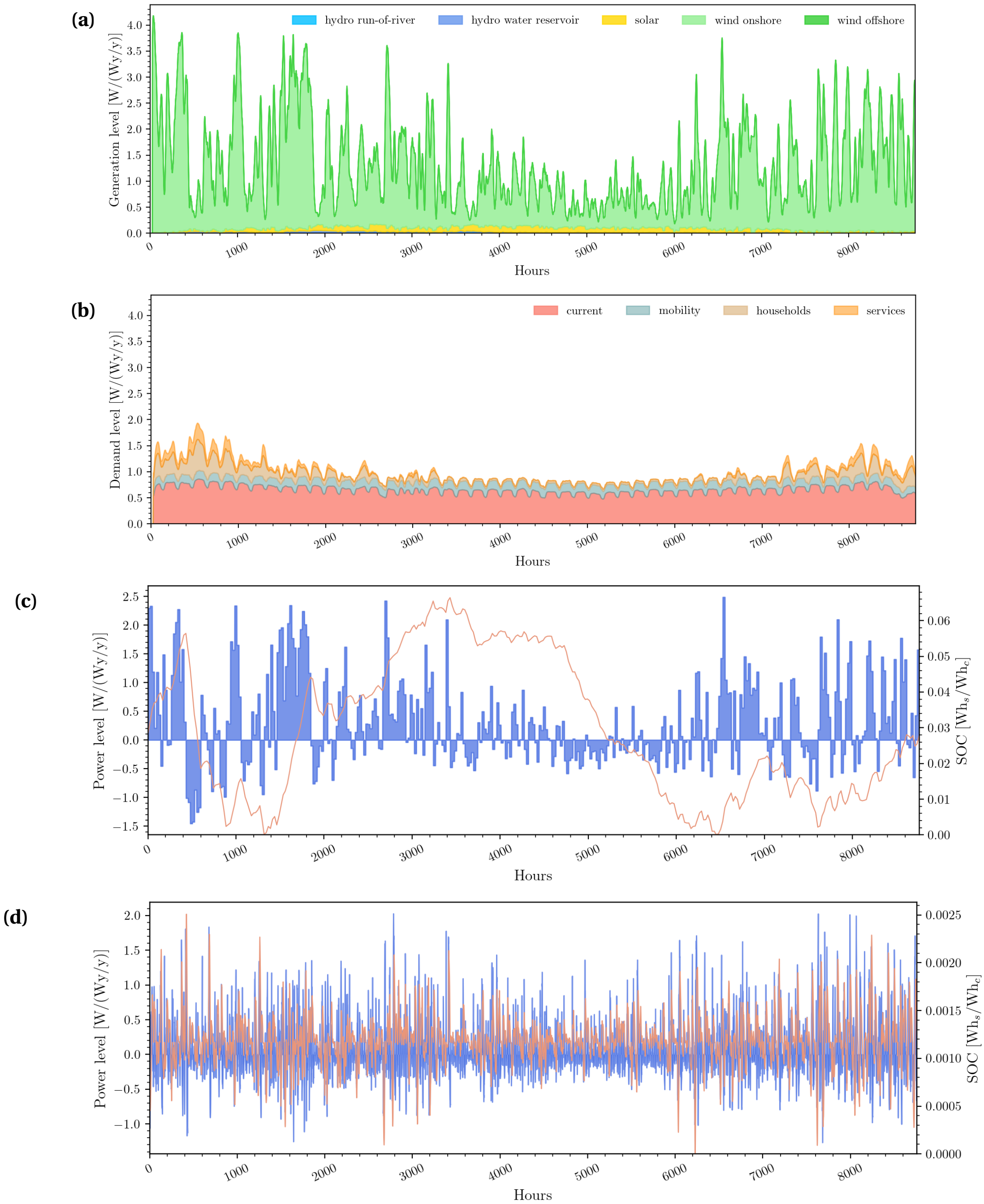

Figure C.7.4 – Hourly electricity production **(a)** and demand **(b)** profiles for *Czechia*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

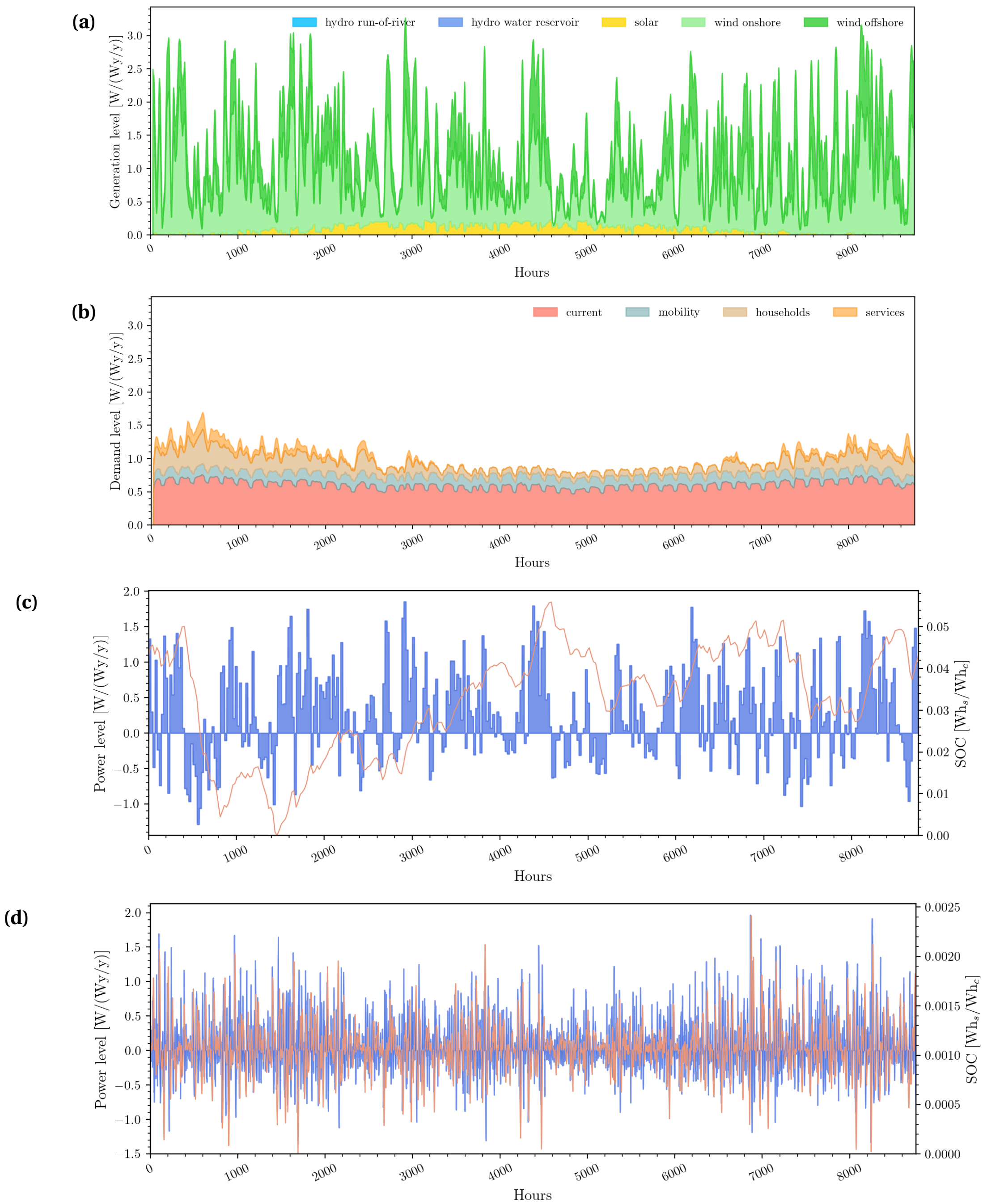

Figure C.7.5 – Hourly electricity production **(a)** and demand **(b)** profiles for *Denmark*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

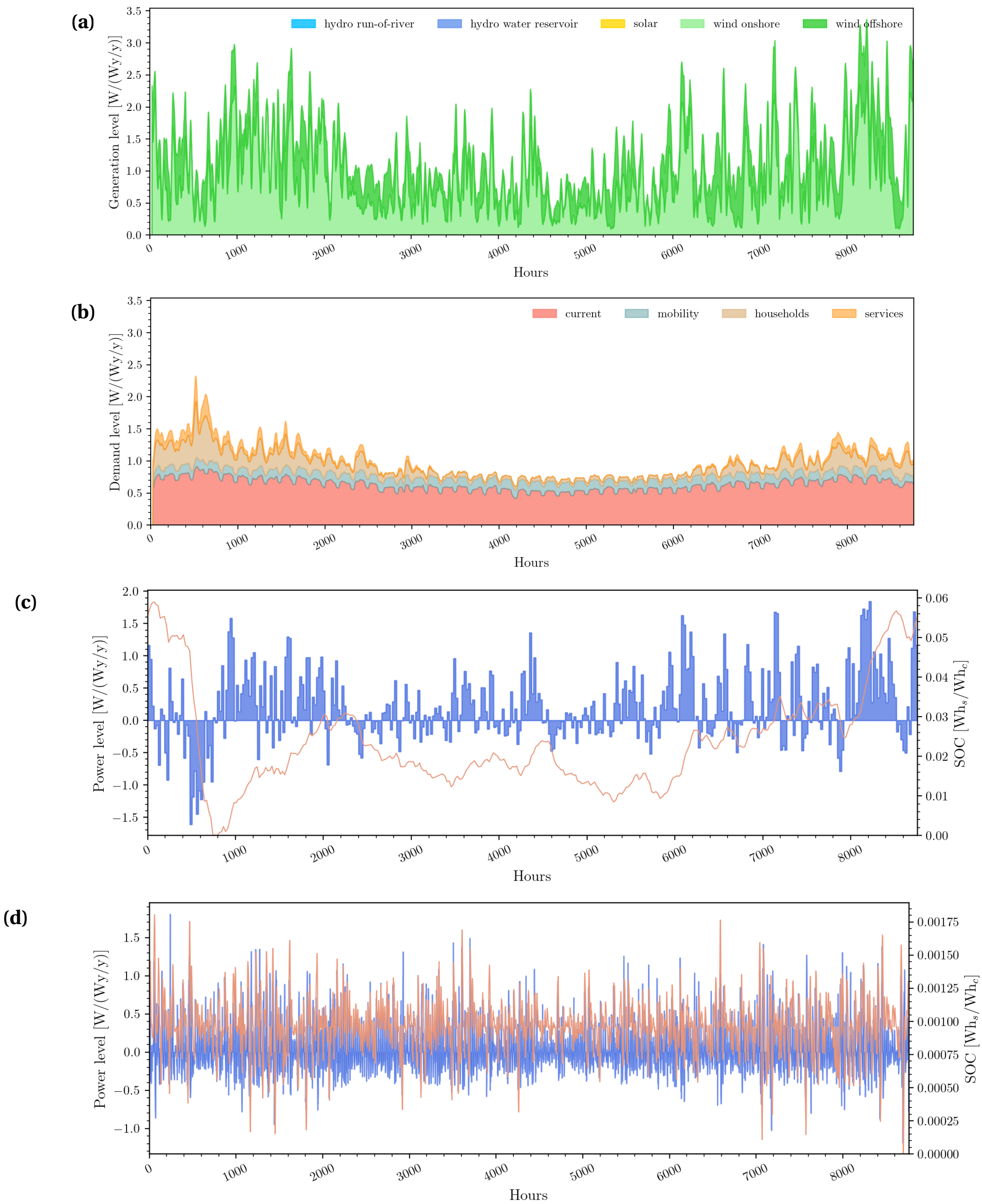

Figure C.7.6 – Hourly electricity production **(a)** and demand **(b)** profiles for *Estonia*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

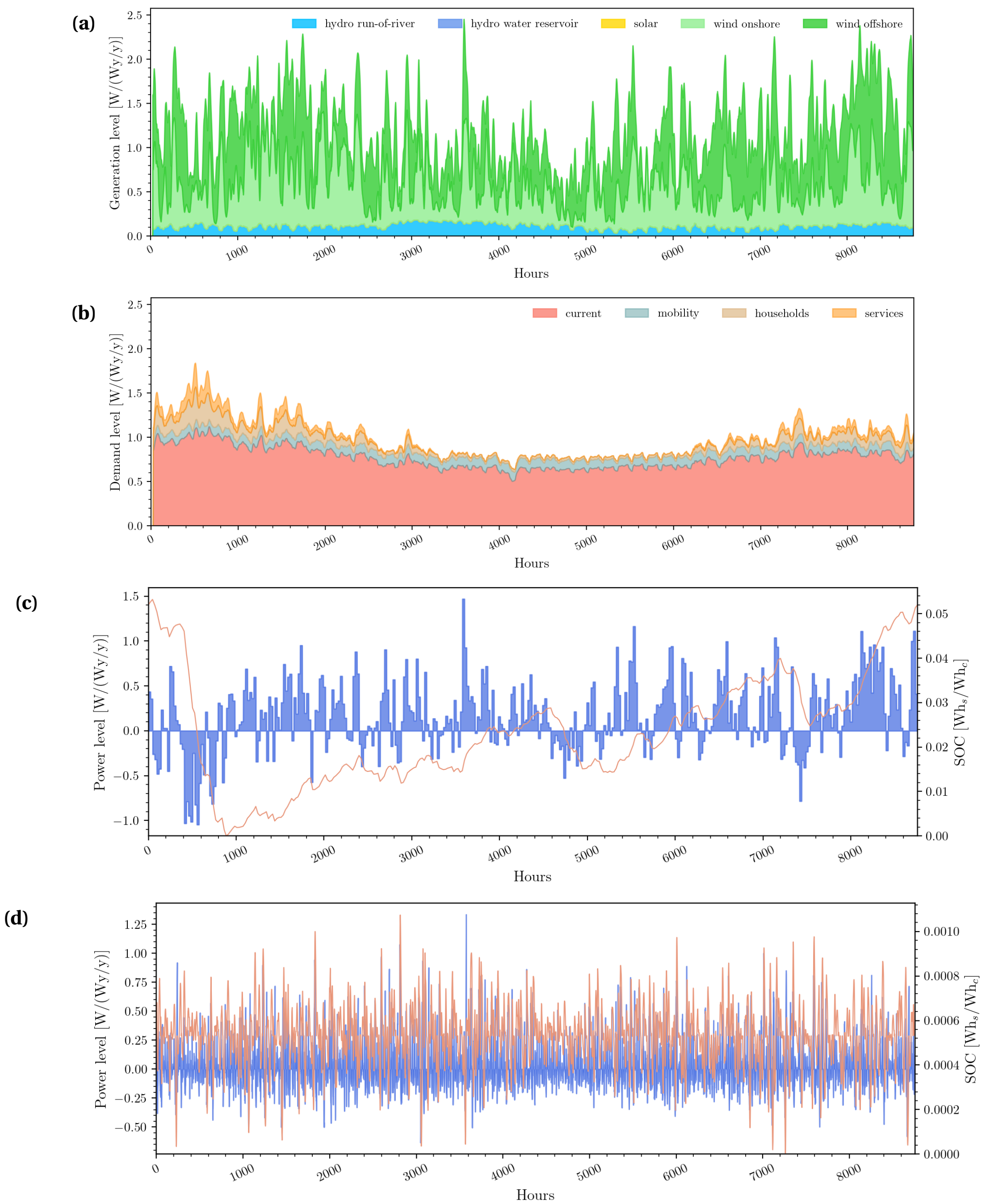

Figure C.7.7 – Hourly electricity production **(a)** and demand **(b)** profiles for *Finland*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

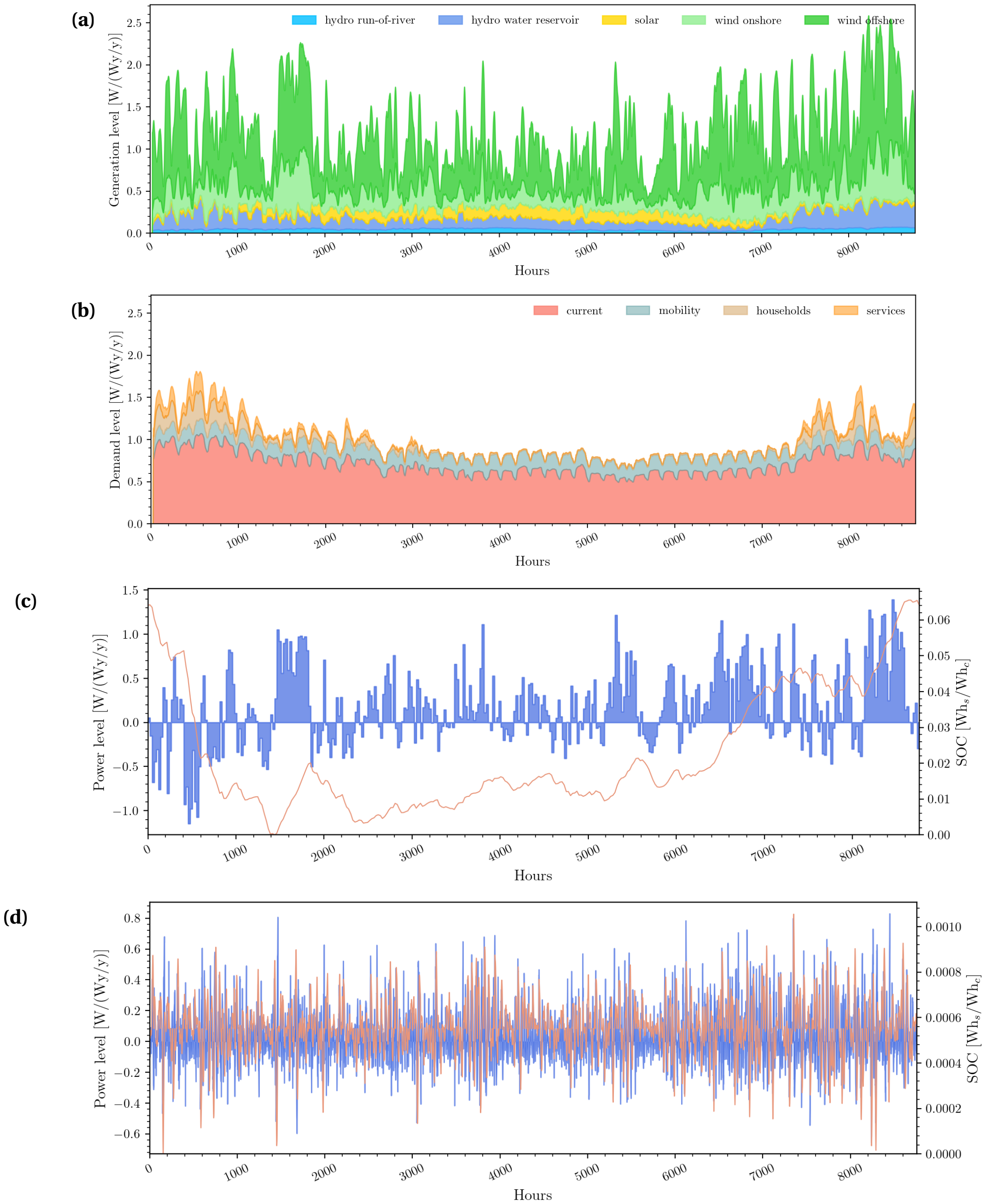

Figure C.7.8 – Hourly electricity production **(a)** and demand **(b)** profiles for *France*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

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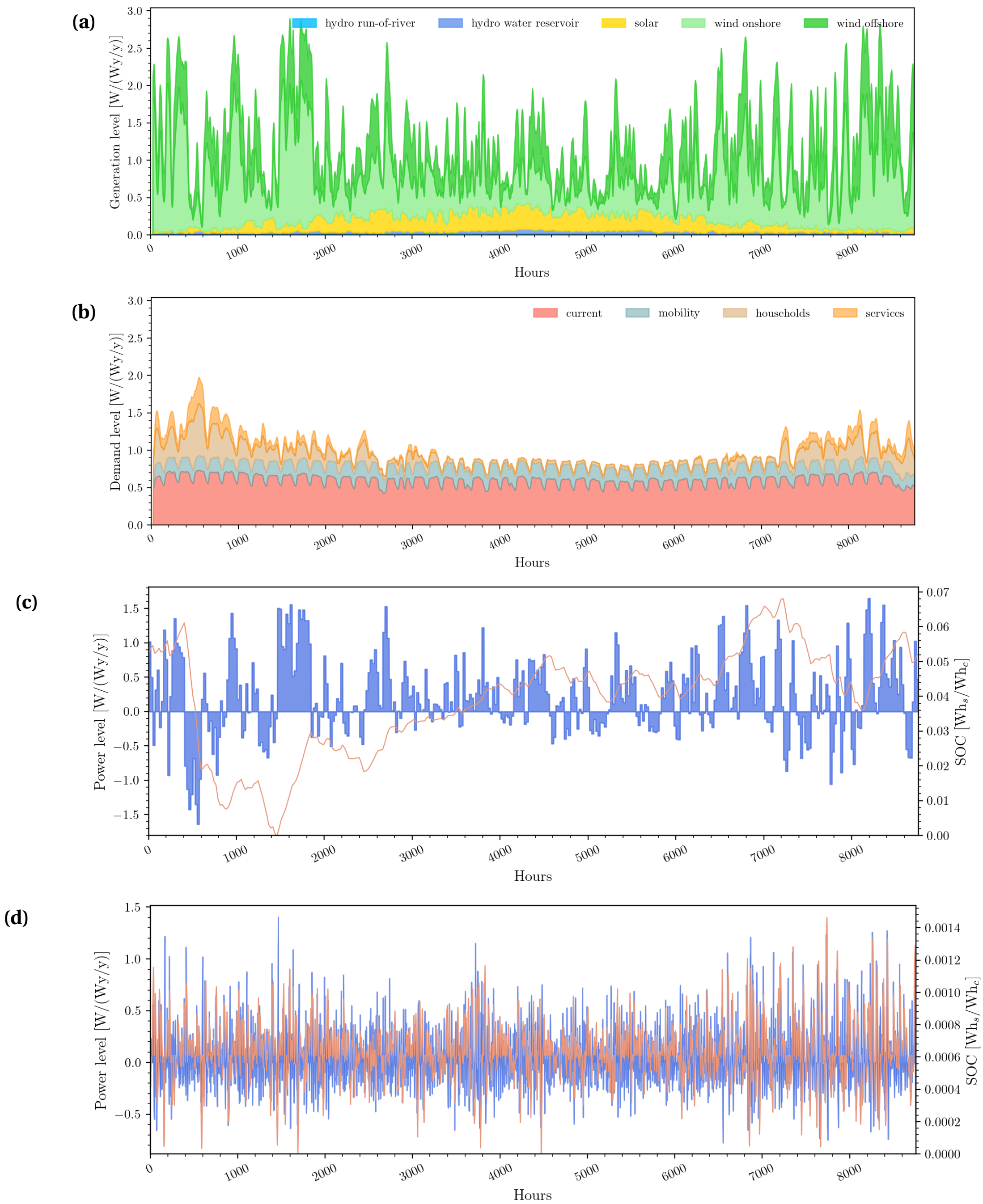

Figure C.7.9 – Hourly electricity production **(a)** and demand **(b)** profiles for *Germany*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

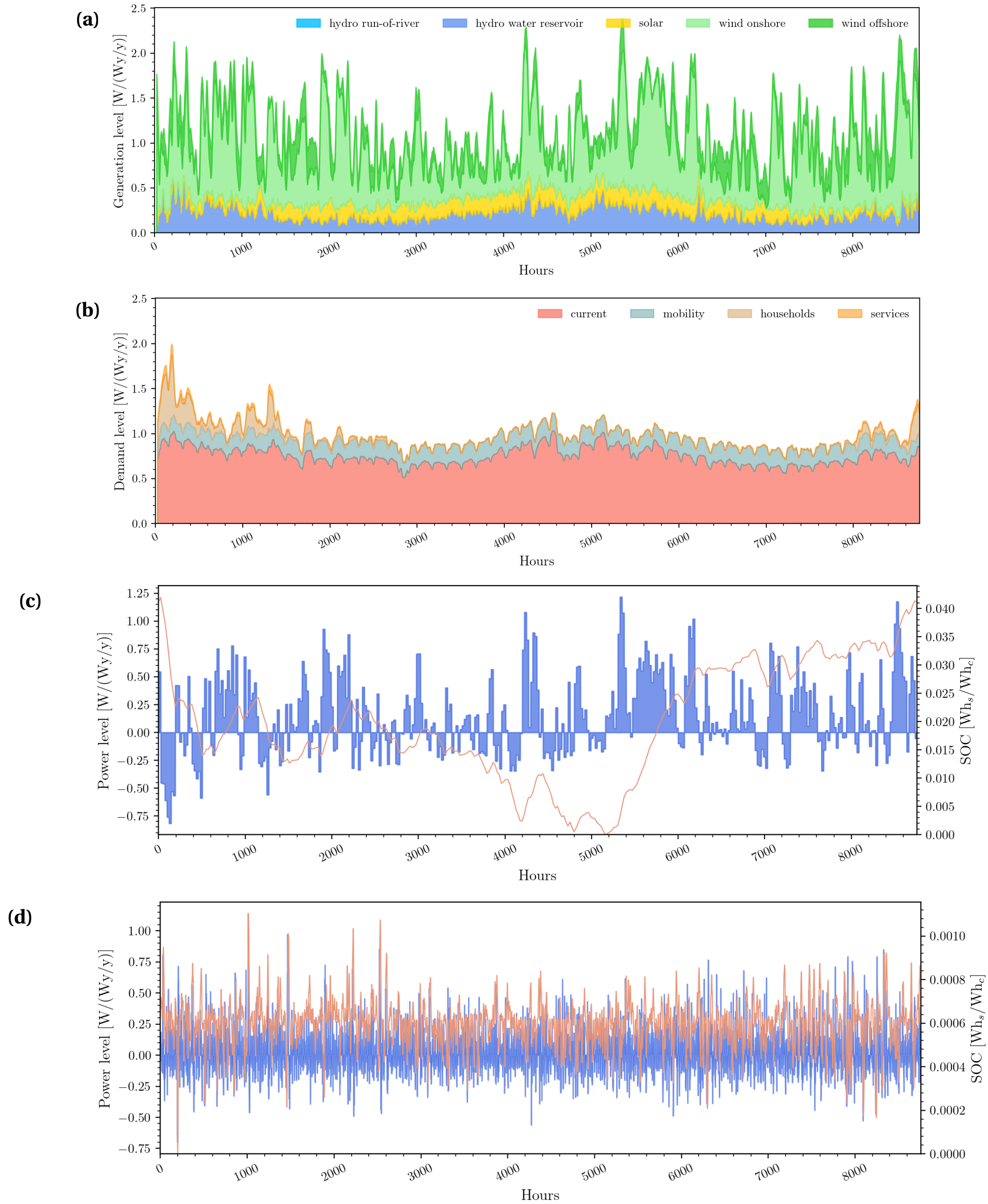

Figure C.7.10 – Hourly electricity production **(a)** and demand **(b)** profiles for *Greece*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

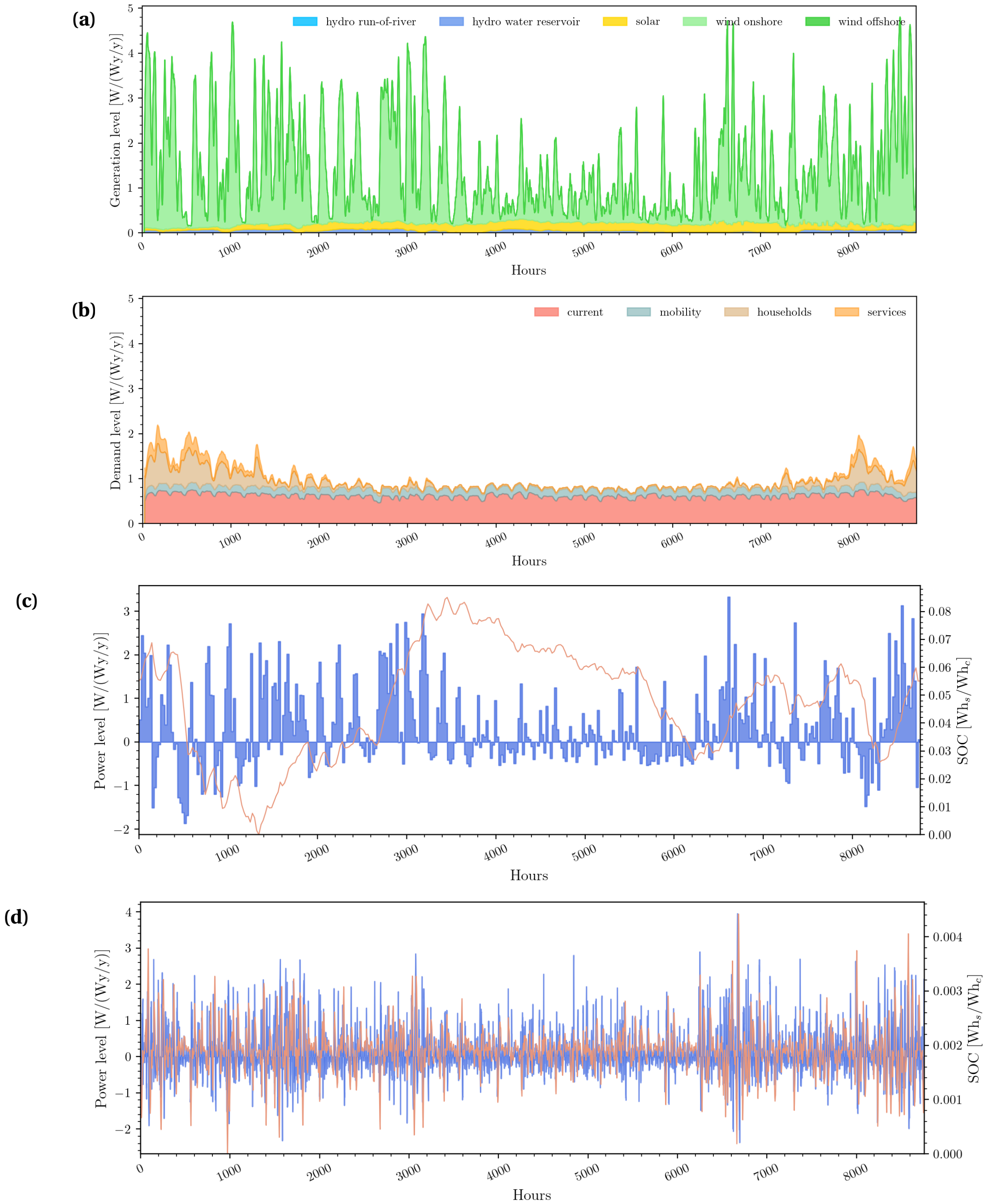

Figure C.7.11 – Hourly electricity production **(a)** and demand **(b)** profiles for *Hungary*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

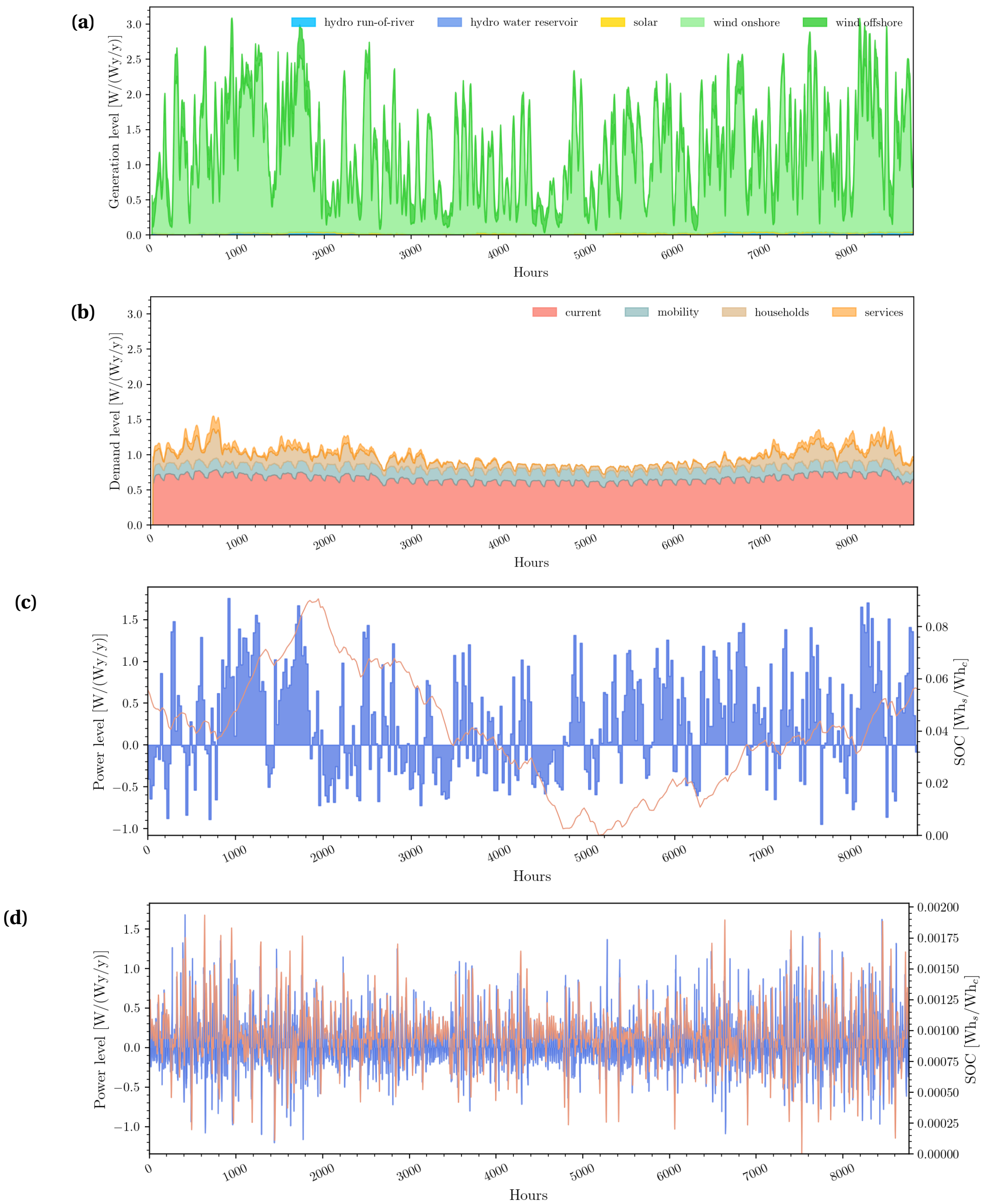

Figure C.7.12 – Hourly electricity production **(a)** and demand **(b)** profiles for *Ireland*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

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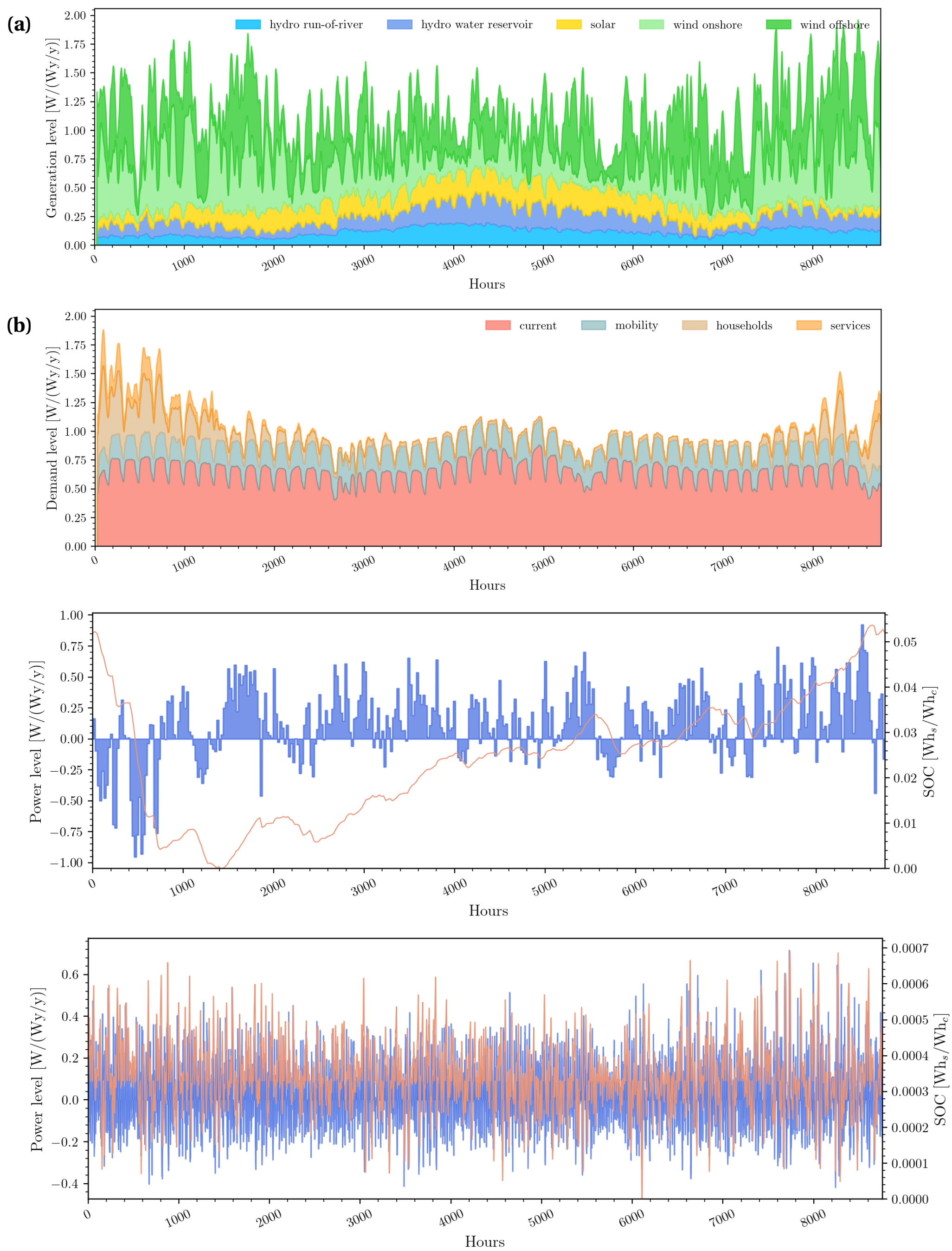

Figure C.7.13 – Hourly electricity production **(a)** and demand **(b)** profiles for *Italy*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

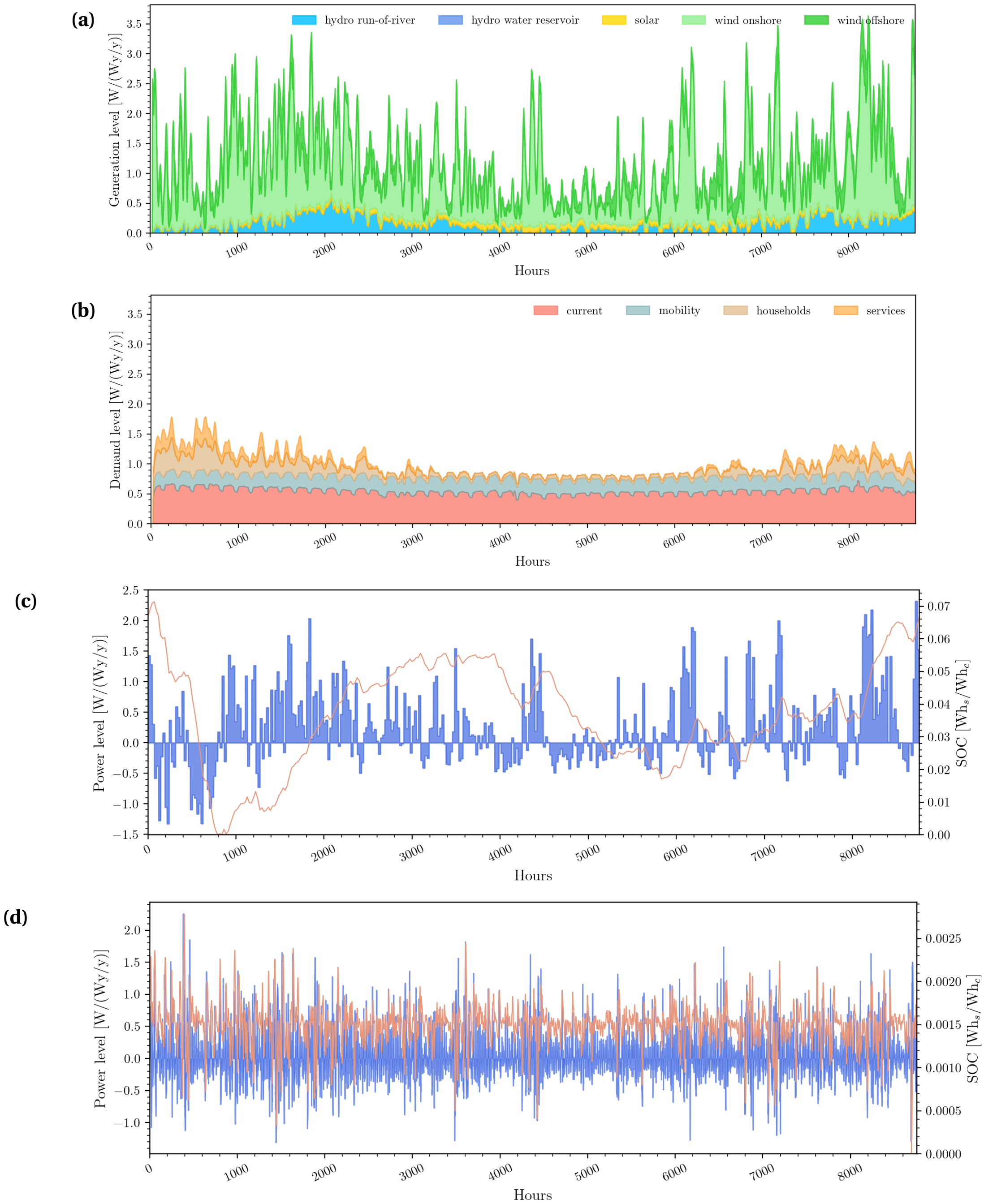

Figure C.7.14 – Hourly electricity production **(a)** and demand **(b)** profiles for *Latvia*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

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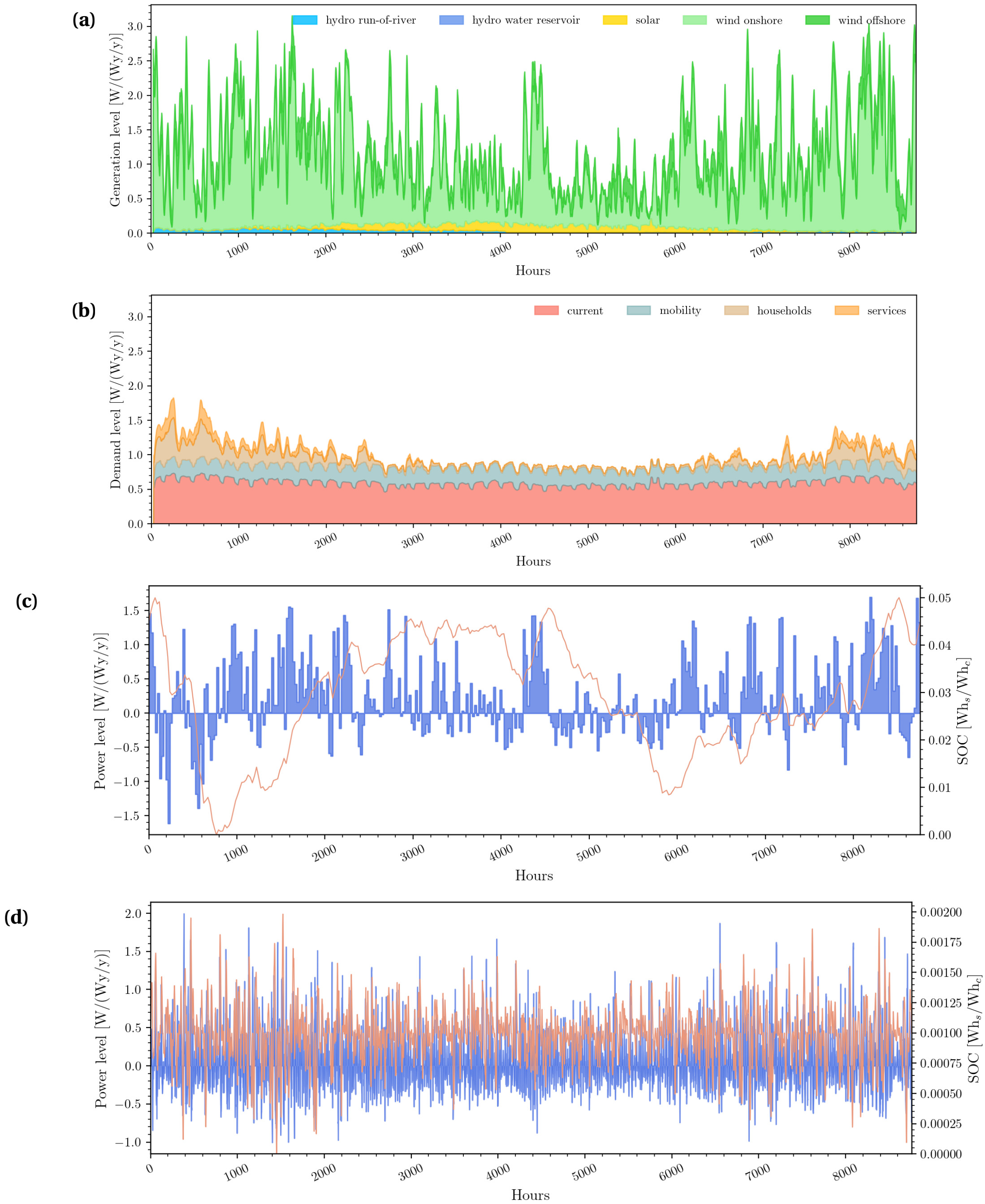

Figure C.7.15 – Hourly electricity production **(a)** and demand **(b)** profiles for *Lithuania*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

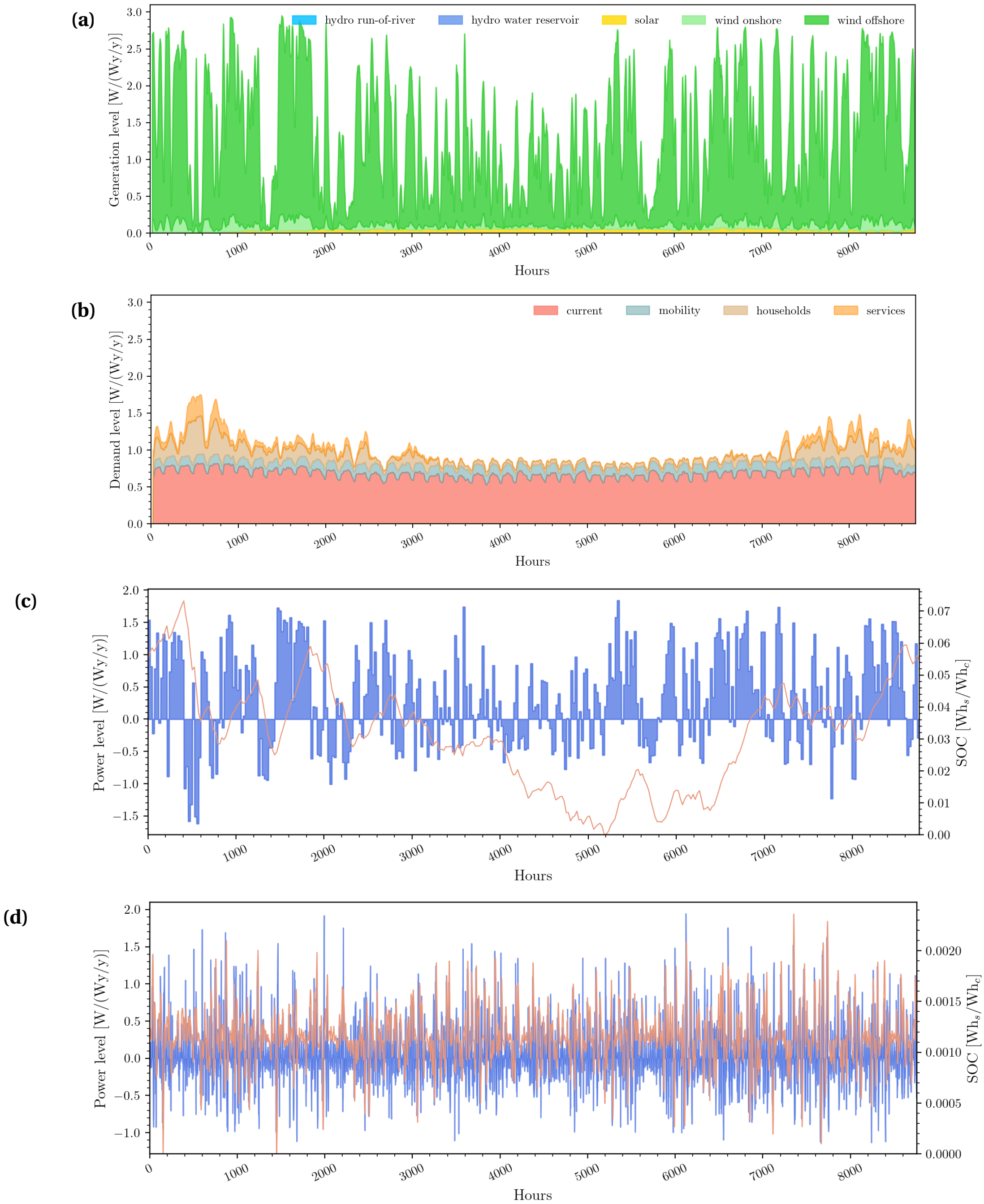

Figure C.7.16 – Hourly electricity production **(a)** and demand **(b)** profiles for *Netherlands*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

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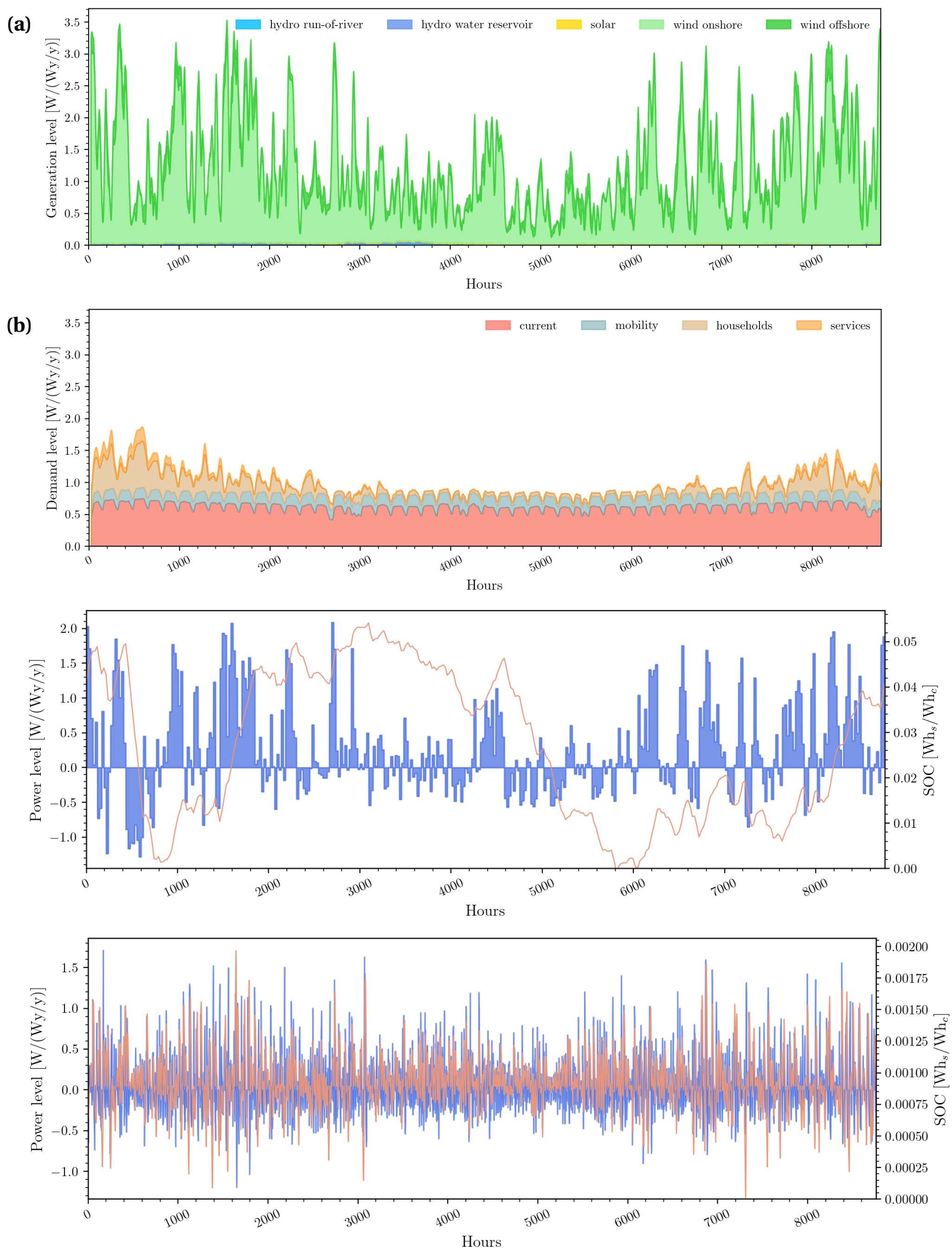

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Figure C.7.17 – Hourly electricity production **(a)** and demand **(b)** profiles for *Poland*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

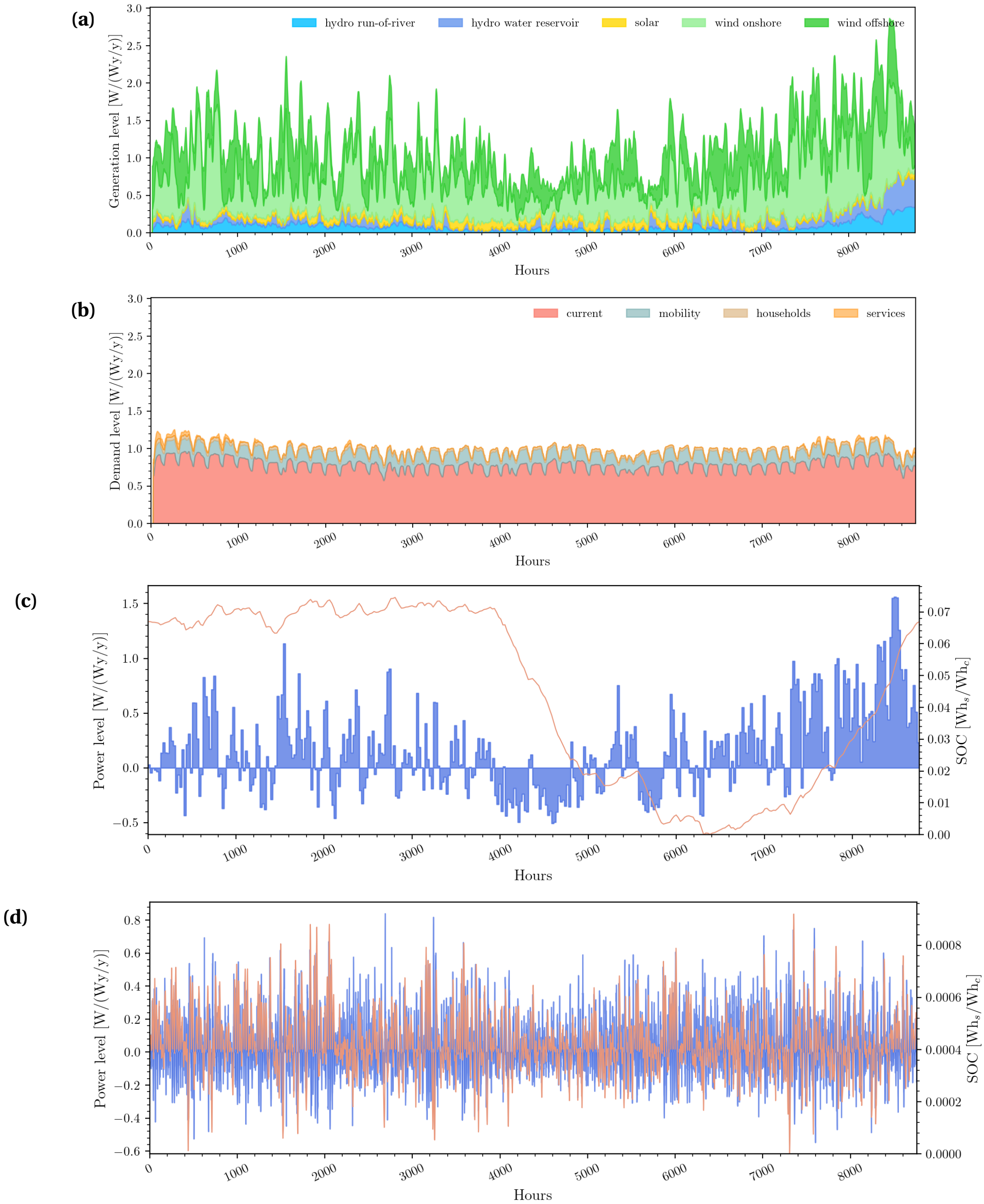

Figure C.7.18 – Hourly electricity production **(a)** and demand **(b)** profiles for *Portugal*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

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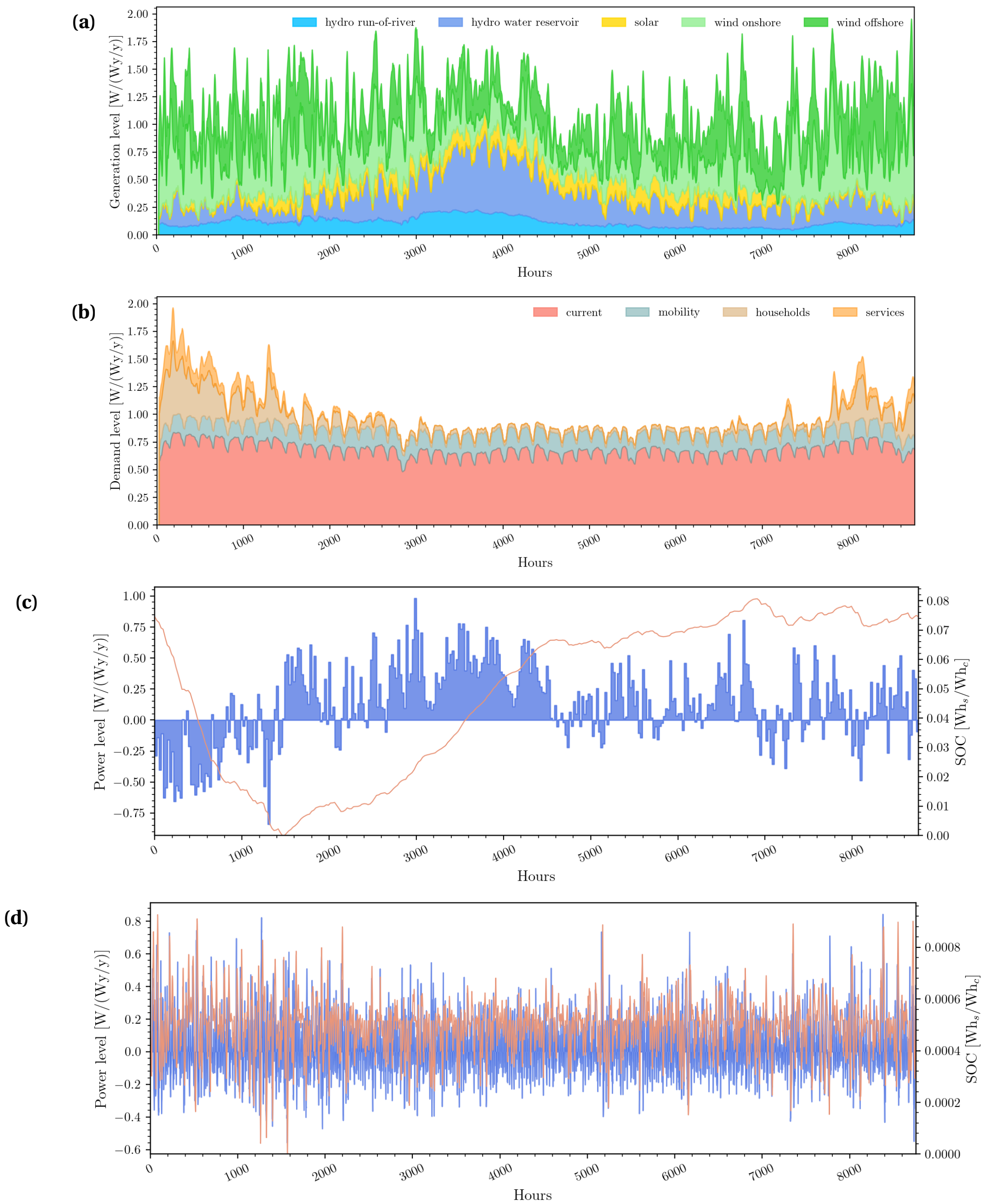

Figure C.7.19 – Hourly electricity production **(a)** and demand **(b)** profiles for *Romania*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

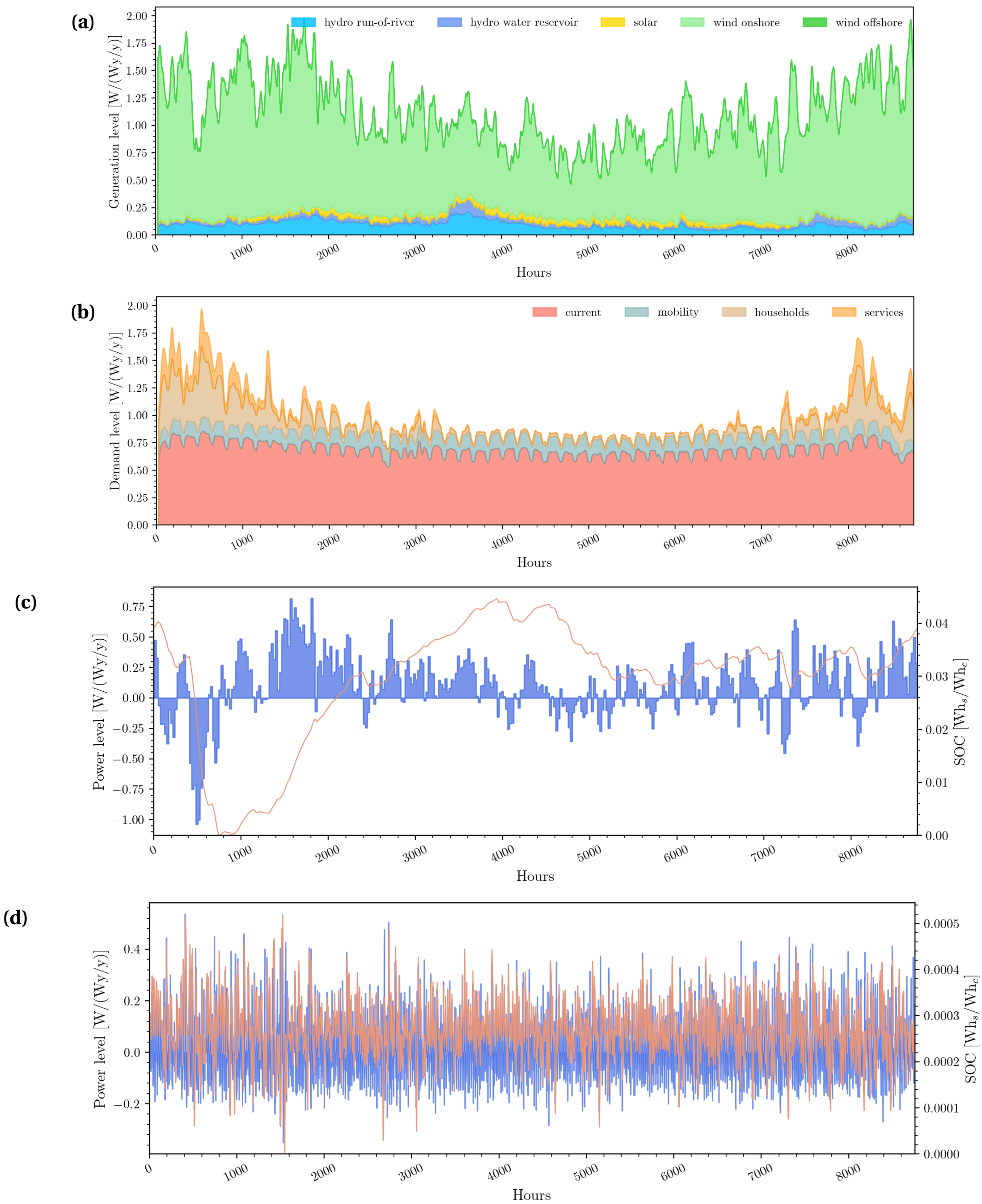

Figure C.7.20 – Hourly electricity production **(a)** and demand **(b)** profiles for *Slovakia*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

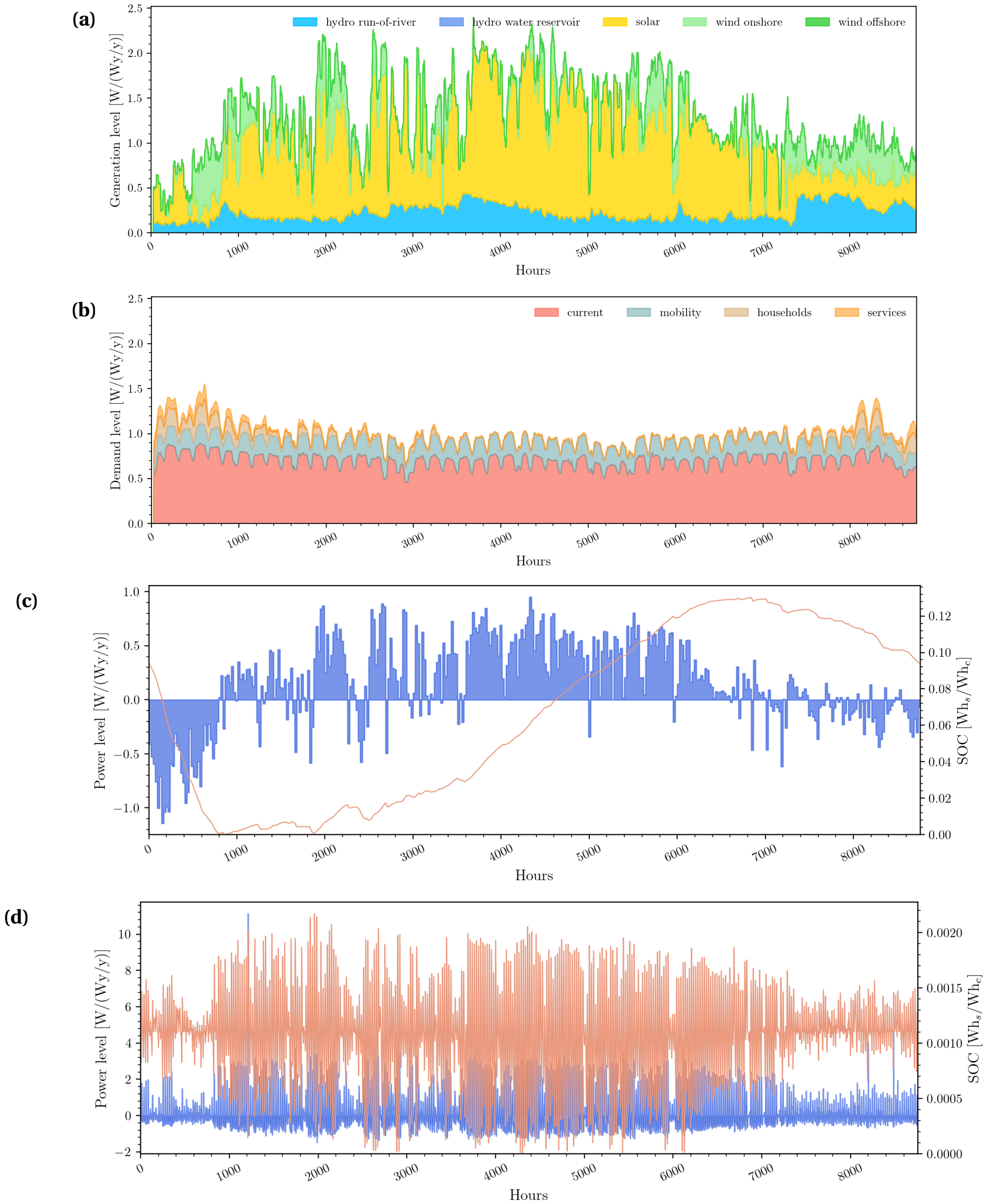

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Figure C.7.21 – Hourly electricity production **(a)** and demand **(b)** profiles for *Slovenia*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

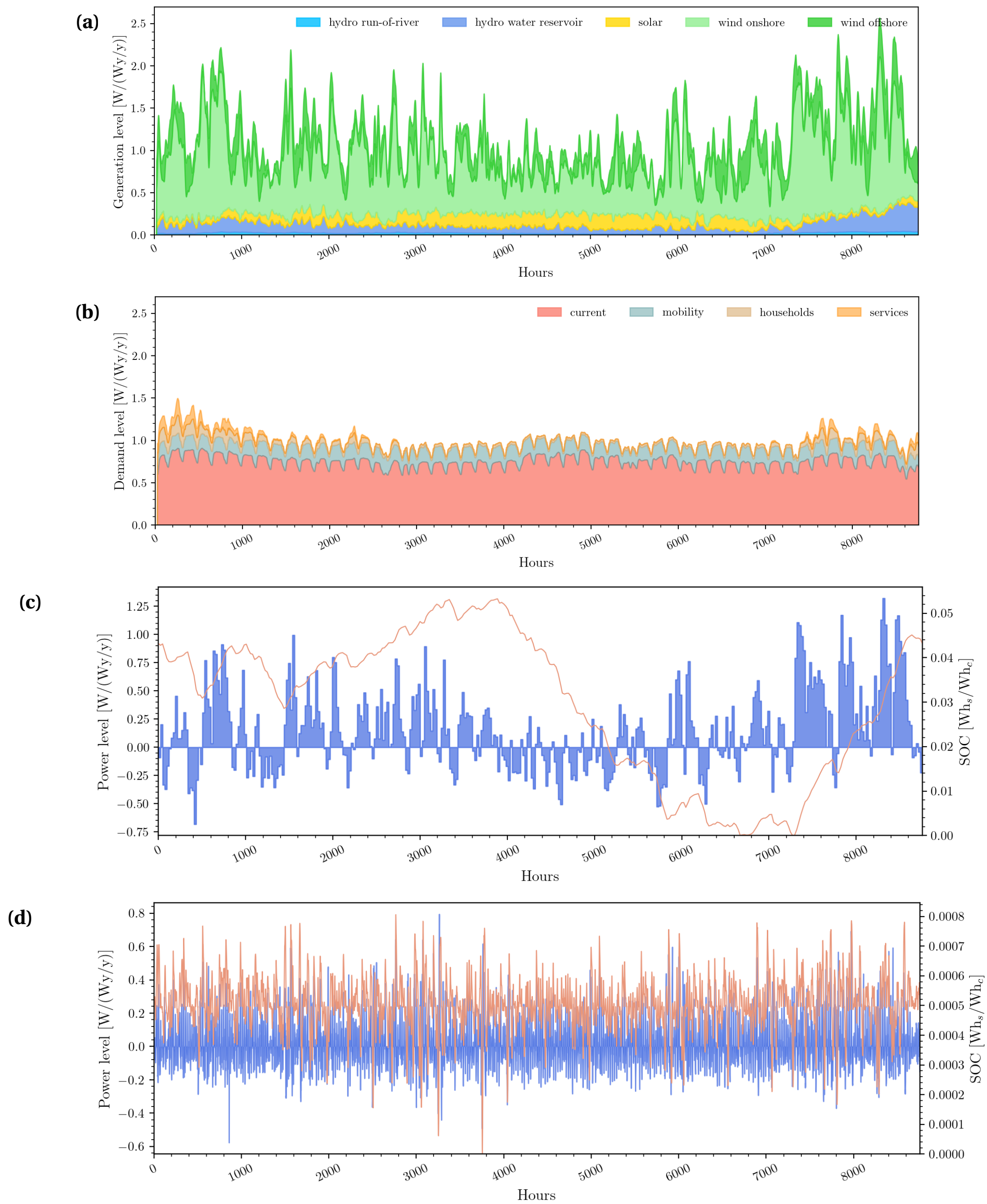

Figure C.7.22 – Hourly electricity production **(a)** and demand **(b)** profiles for *Spain*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

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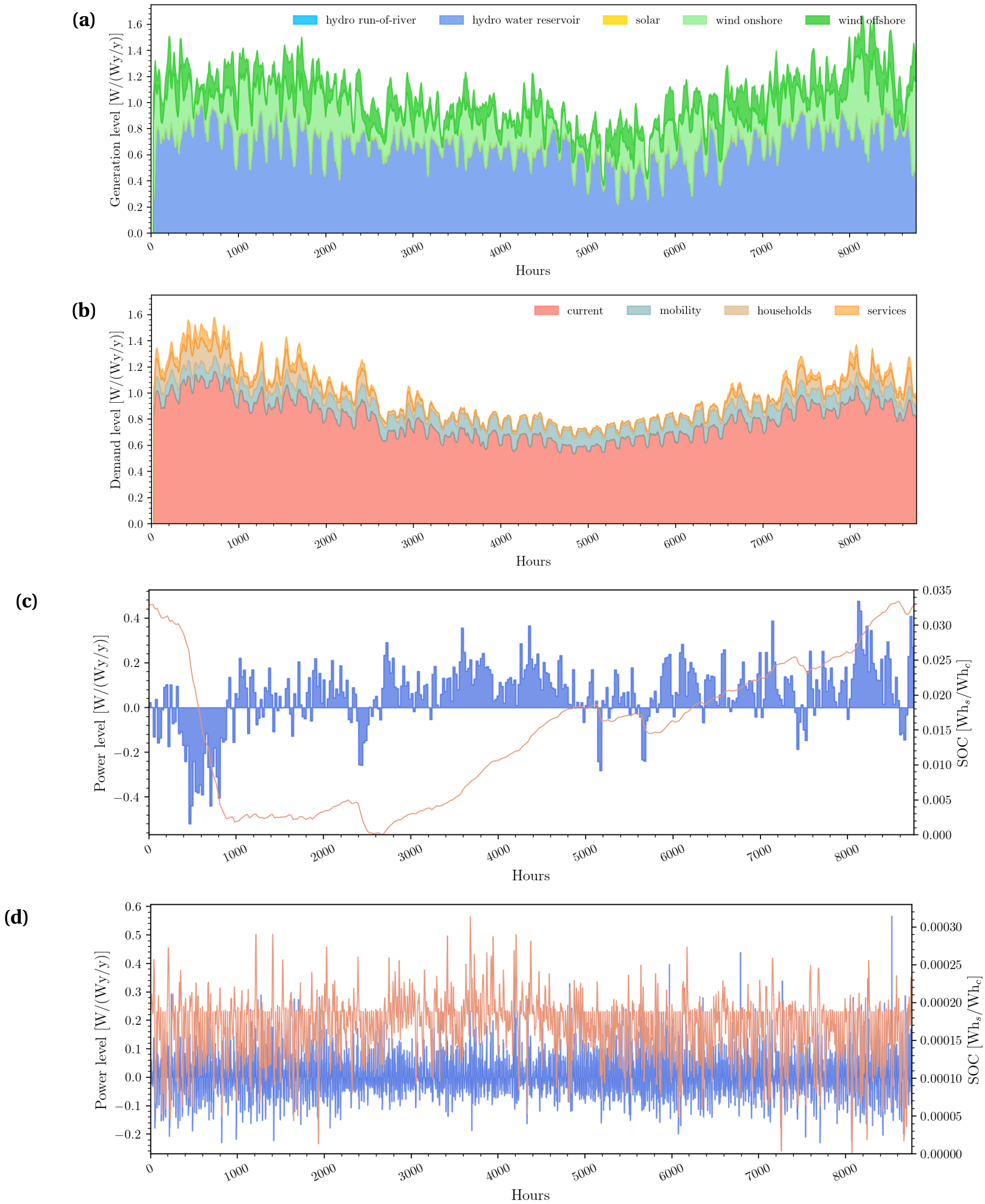

Figure C.7.23 – Hourly electricity production **(a)** and demand **(b)** profiles for *Sweden*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

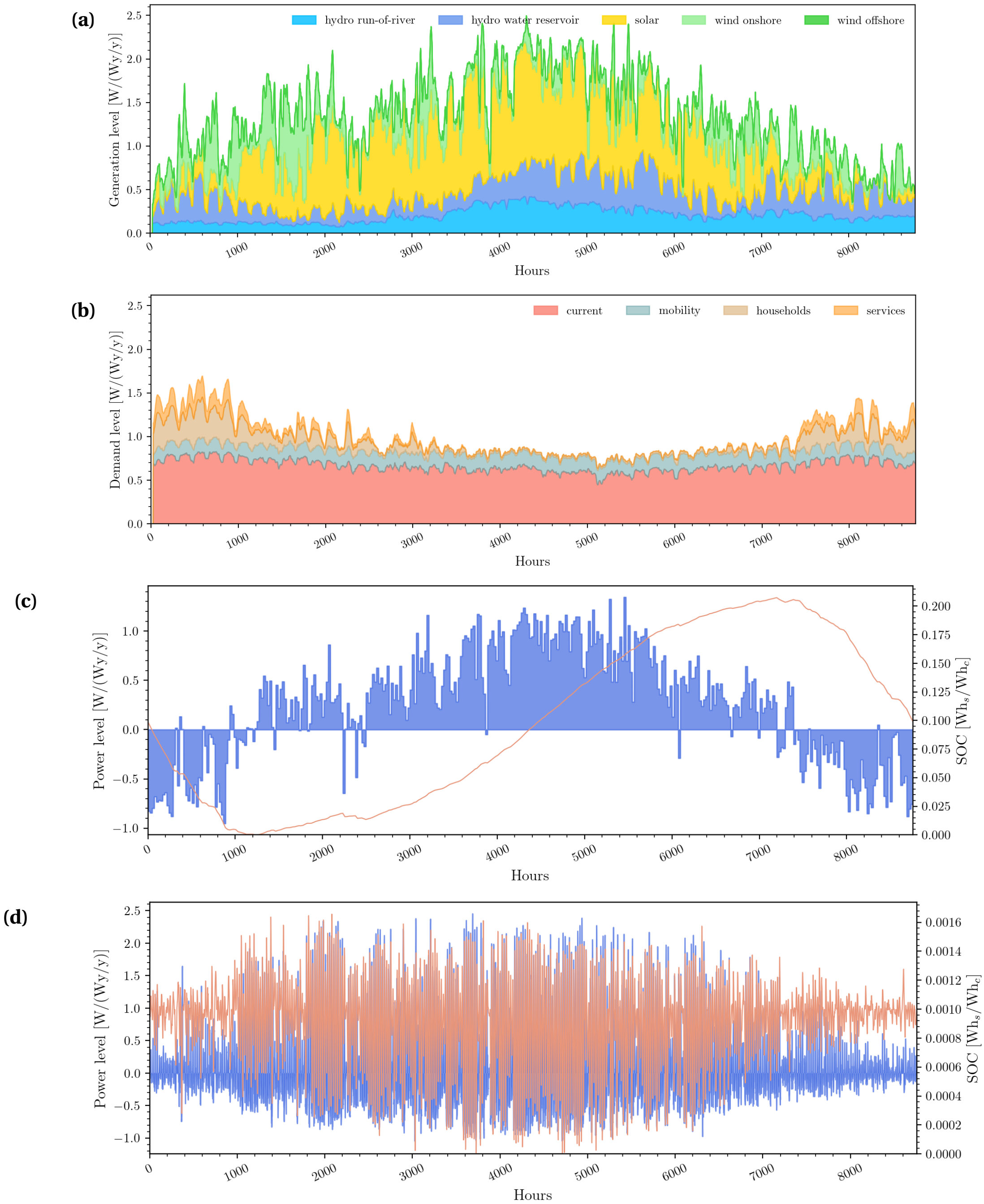

Figure C.7.24 – Hourly electricity production **(a)** and demand **(b)** profiles for *Switzerland*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

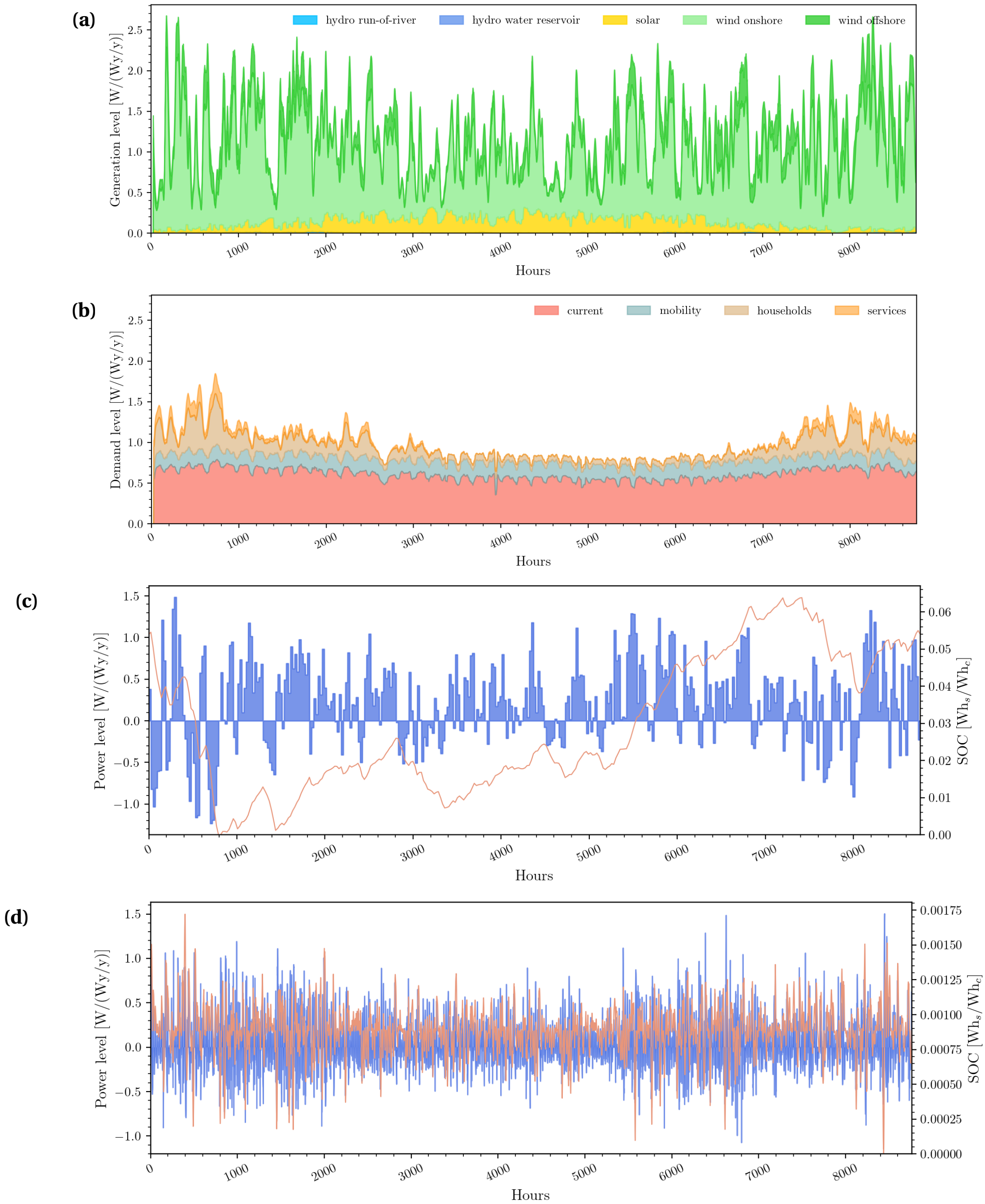

Figure C.7.25 – Hourly electricity production **(a)** and demand **(b)** profiles for *United Kingdom*. Hourly power levels (in blue) and State of Charge (in red) of the long-term **(c)** and short-term **(d)** storage. Results obtained for the best observed solution.

C.8 Self-sufficiency and renewable potential

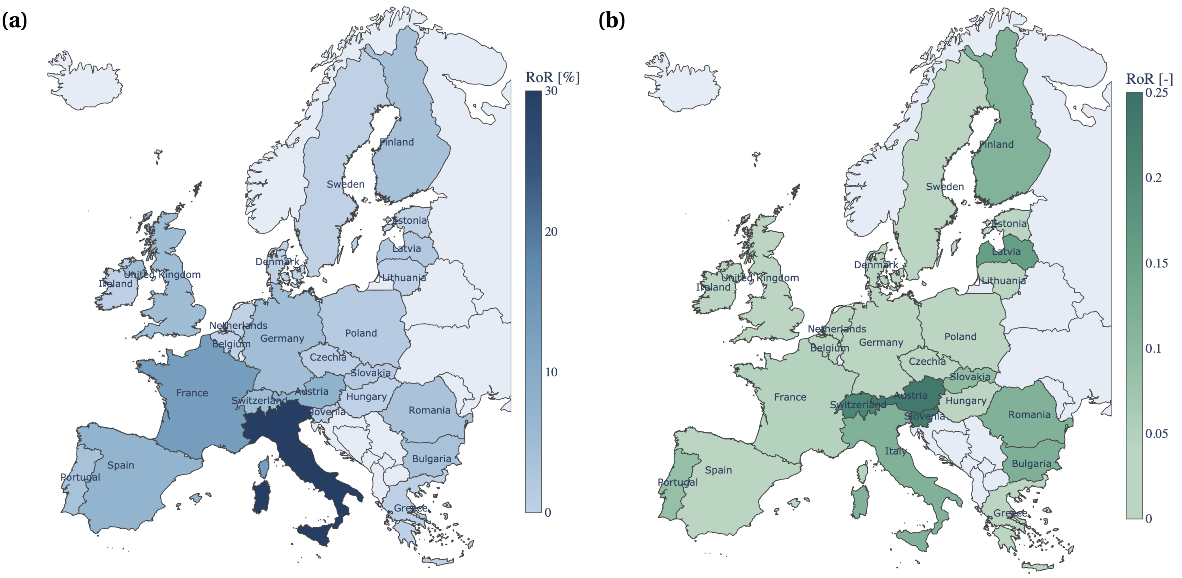

Figure C.8.1 – Potential generation of *hydro run-of-river* in Europe. **(a)**, percentage [%] of the total European potential (Table C.8.1). **(b)**, potential generation in MWh of produced electricity per MWh of demand [-] (Table C.8.2).

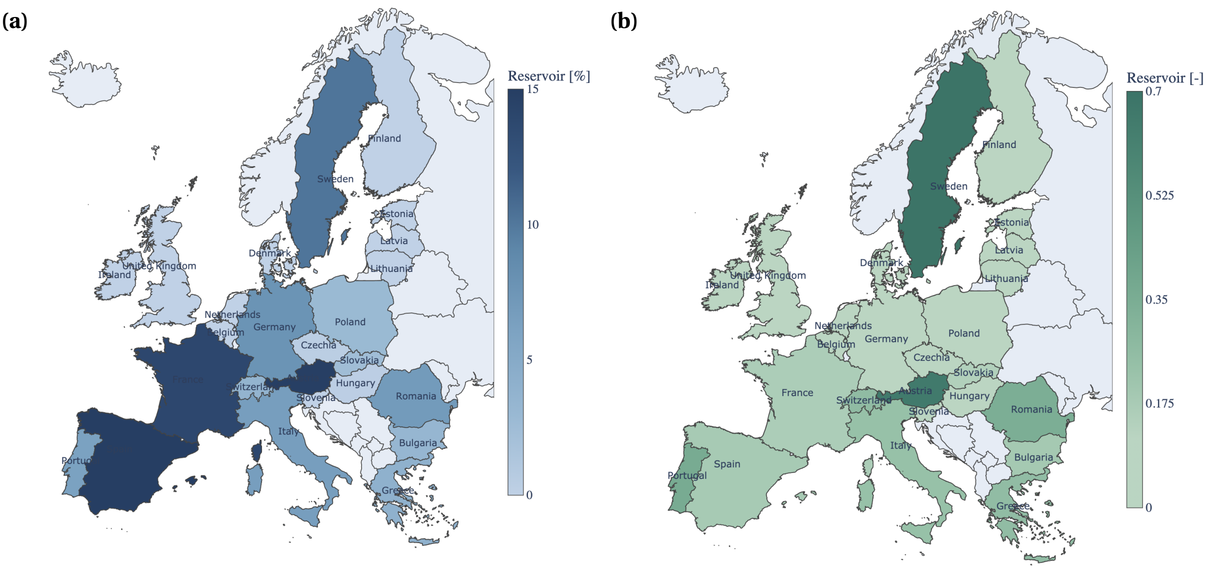

Figure C.8.2 – Potential generation of *hydro reservoir* in Europe. **(a)**, percentage [%] of the total European potential (Table C.8.1). **(b)**, potential generation in MWh of produced electricity per MWh of demand [-] (Table C.8.2).

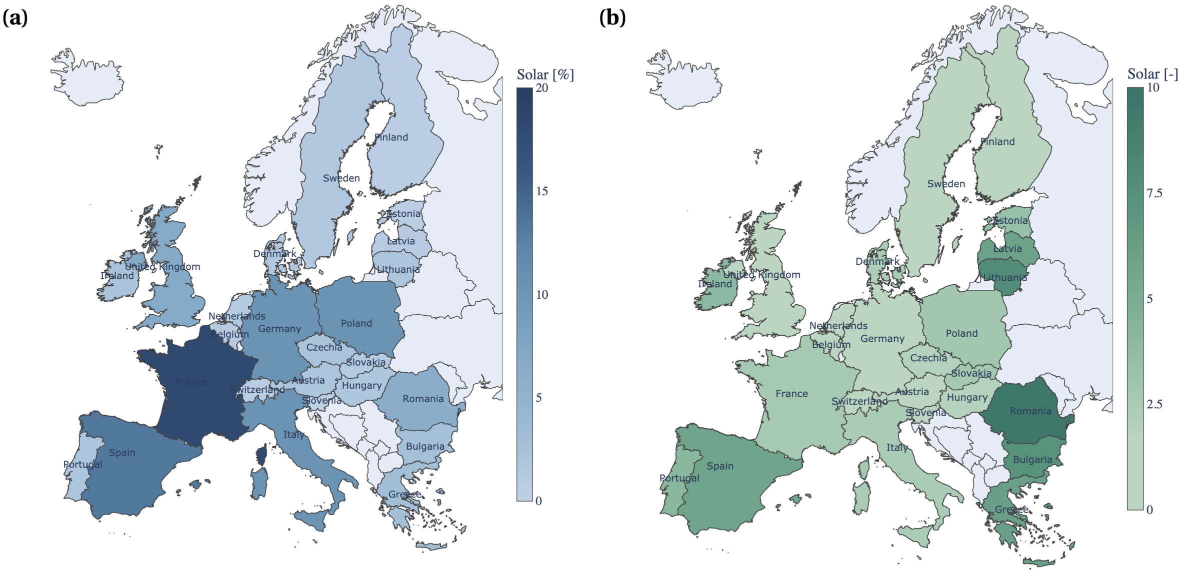

Figure C.8.3 – Potential generation of solar PV in Europe. **(a)**, percentage [%] of the total European potential (Table C.8.1). **(b)**, potential generation in MWh of produced electricity per MWh of demand [-] (Table C.8.2).

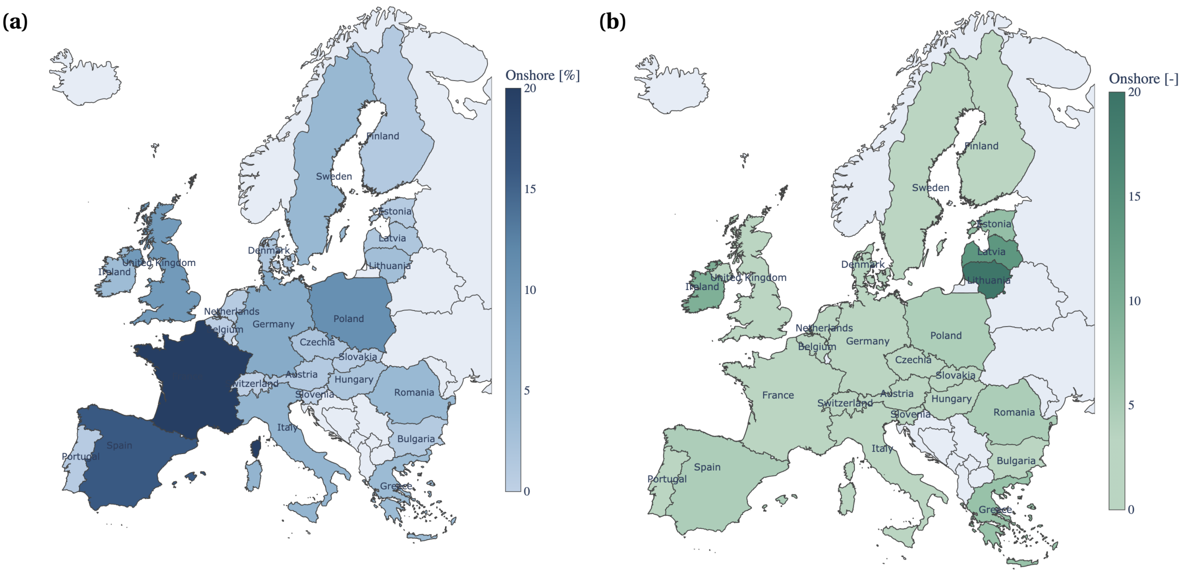

Figure C.8.4 – Potential generation of *wind onshore* in Europe. **(a)**, percentage [%] of the total European potential (Table C.8.1). **(b)**, potential generation in MWh of produced electricity per MWh of demand [-] (Table C.8.2).

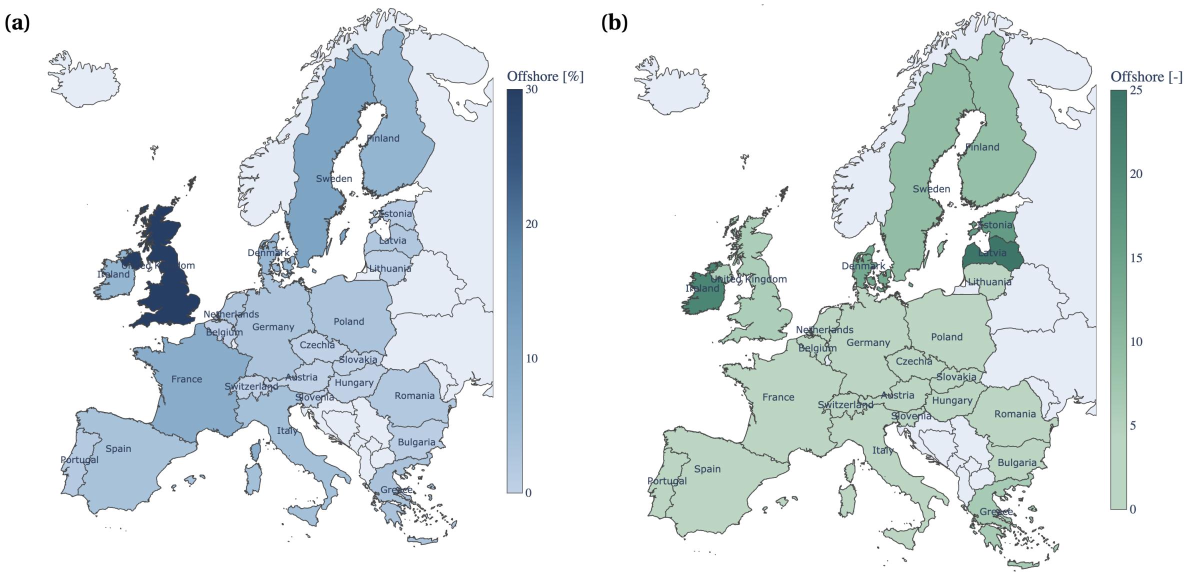

Figure C.8.5 – Potential generation of *wind offshore* in Europe. **(a)**, percentage [%] of the total European potential (Table C.8.1). **(b)**, potential generation in MWh of produced electricity per MWh of demand [-] (Table C.8.2).

Country	Hydro [%] Run-of-river	Hydro [%] Reservoir	Solar [%] Photovoltaic	Wind [%] Onshore	Wind [%] Offshore
Austria	8.14	14.87	1.83	1.35	-
Belgium	0.22	-	1.09	0.28	0.15
Bulgaria	3.72	3.41	2.92	1.24	1.04
Czechia	0.70	0.42	2.11	2.09	-
Denmark	0.01	-	1.58	1.80	6.53
Estonia	0.01	-	0.59	1.00	1.60
Finland	3.88	-	0.73	1.26	7.12
France	13.49	13.91	18.10	20.53	9.82
Germany	4.86	7.80	10.56	6.70	3.14
Greece	0.37	4.08	3.04	3.74	3.38
Hungary	0.10	0.37	1.74	2.13	-
Ireland	0.27	-	2.36	3.57	6.97
Italy	32.64	6.65	10.43	4.91	4.33
Latvia	1.89	-	1.05	1.85	2.46
Lithuania	0.32	-	2.00	3.09	0.62
Netherlands	0.05	-	1.21	1.07	2.88
Poland	1.53	2.92	10.46	10.92	3.35
Portugal	3.81	6.27	1.91	0.94	1.69
Romania	3.40	7.02	6.21	3.98	2.37
Slovakia	1.49	2.47	1.20	0.74	-
Slovenia	1.33	-	0.22	0.07	-
Spain	7.56	15.82	13.30	15.90	3.80
Sweden	-	10.25	1.51	4.18	11.95
Switzerland	5.20	3.74	0.86	0.35	-
United Kingdom	5.01	-	6.88	9.48	30.85
Europe	100.00	100.00	100.00	100.00	100.00

Table C.8.1 – Distribution of generation potentials from renewable sources in Europe. Values given as percentage of the total potential.

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	Hydro [-]		Solar [-]	Wind [-]	
Country	**Run-of-river**	**Reservoir**	**Photovoltaic**	**Onshore**	**Offshore**
Austria	0.235	0.660	1.469	1.546	-
Belgium	0.002	-	0.758	0.188	0.156
Bulgaria	0.118	0.191	7.326	2.241	2.876
Czechia	0.015	0.018	2.055	2.084	-
Denmark	0.000	-	2.443	3.575	13.435
Estonia	0.001	-	3.428	7.169	16.375
Finland	0.114	-	0.510	1.548	8.740
France	0.048	0.166	2.710	3.283	1.998
Germany	0.018	0.029	1.099	0.732	0.463
Greece	0.011	0.263	6.211	6.643	6.541
Hungary	0.004	0.062	1.946	3.033	-
Ireland	0.020	-	4.068	9.509	21.136
Italy	0.117	0.237	2.485	0.971	1.268
Latvia	0.159	-	5.985	13.889	24.646
Lithuania	0.036	-	7.866	19.394	4.028
Netherlands	0.001	-	0.572	0.597	2.670
Poland	0.019	0.032	2.880	4.592	1.622
Portugal	0.088	0.363	4.116	1.759	3.476
Romania	0.116	0.346	9.573	4.703	3.575
Slovakia	0.093	0.150	2.824	1.810	-
Slovenia	0.231	-	0.997	0.208	-
Spain	0.024	0.183	5.706	4.655	1.506
Sweden	-	0.695	0.665	2.843	9.243
Switzerland	0.209	0.266	0.774	0.352	-
United Kingdom	0.016	-	1.195	2.340	5.943
Europe	0.046	0.154	2.089	2.103	2.235

Table C.8.2 – Potential generation of renewable technologies in MWh of produced electricity per MWh of demand by country [-].

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Country	Hydro [MWh/capita]		Solar [MWh/capita]	Wind [MWh/capita]	
	Run-of-river	Reservoir	Photovoltaic	Onshore	Offshore
Austria	2.50	7.03	15.64	16.47	-
Belgium	0.02	-	8.33	2.07	1.72
Bulgaria	0.80	1.30	49.65	15.19	19.49
Czechia	0.14	0.17	19.51	19.79	-
Denmark	0.00	-	23.18	33.92	127.46
Estonia	0.01	-	33.65	70.37	160.74
Finland	2.23	-	9.98	30.27	170.92
France	0.46	1.61	26.35	31.91	19.42
Germany	0.18	0.29	10.82	7.21	4.56
Greece	0.07	1.68	39.57	42.32	41.67
Hungary	0.03	0.44	13.91	21.68	-
Ireland	0.18	-	36.76	85.94	191.03
Italy	0.87	1.77	18.57	7.26	9.48
Latvia	1.08	-	40.92	94.95	168.50
Lithuania	0.26	-	57.32	141.31	29.35
Netherlands	0.01	-	5.51	5.75	25.72
Poland	0.13	0.23	20.73	33.06	11.68
Portugal	0.55	2.27	25.75	11.01	21.75
Romania	0.52	1.56	43.06	21.15	16.08
Slovakia	0.72	1.16	21.86	14.01	-
Slovenia	2.10	-	9.06	1.89	-
Spain	0.17	1.31	40.81	33.29	10.77
Sweden	-	11.76	11.25	48.08	156.35
Switzerland	2.12	2.71	7.88	3.59	-
United Kingdom	0.12	-	8.75	17.14	43.53
Europe	0.40	1.32	17.88	18.00	19.13

Table C.8.3 – Annual potential generation per inhabitant [MWh/capita] by country and technology.

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	No storage		Storage	
Country	**Current [-]**	**Potential [-]**	**Current [-]**	**Potential [-]**
Austria	0.368	3.911	0.302	3.209
Belgium	0.103	1.104	0.069	0.740
Bulgaria	0.113	12.753	0.097	10.944
Czechia	0.049	4.171	0.036	3.087
Denmark	0.312	19.454	0.234	14.583
Estonia	0.057	26.973	0.045	21.482
Finland	0.173	10.912	0.145	9.144
France	0.151	8.204	0.125	6.811
Germany	0.229	2.342	0.181	1.844
Greece	0.217	19.657	0.185	16.771
Hungary	0.025	5.044	0.017	3.496
Ireland	0.238	34.733	0.179	26.156
Italy	0.198	5.079	0.173	4.439
Latvia	0.170	44.678	0.131	34.361
Lithuania	0.093	31.324	0.072	24.502
Netherlands	0.095	3.838	0.069	2.773
Poland	0.063	9.144	0.048	6.959
Portugal	0.342	9.803	0.290	8.297
Romania	0.272	18.314	0.236	15.838
Slovakia	0.116	4.877	0.103	4.332
Slovenia	0.246	1.437	0.192	1.122
Spain	0.281	12.073	0.241	10.355
Sweden	0.500	13.448	0.467	12.550
Switzerland	0.429	1.599	0.318	1.187
United Kingdom	0.170	9.491	0.135	7.530
Europe	0.186	6.627	0.164	5.844

Table C.8.4 – Current and potential generation as fraction [-] of the electricity demand per country and all Europe. The results are shown for the solutions without storage, hence the demand equals the annual electricity consumption, and with storage, which accounts for the charge and discharge losses of the battery and power-to-gas. The countries with a potential capacity that is lower than the sum of the electricity demand and losses are highlighted in red.

	Hydro [-]		Solar [-]	Wind [-]	
Country	**Run-of-river**	**Reservoir**	**Photovoltaic**	**Onshore**	**Offshore**
Austria	1.000	0.911	0.010	0.238	-
Belgium	1.000	-	1.501	1.000	1.000
Bulgaria	0.961	0.198	0.028	0.112	0.193
Czechia	0.917	0.719	0.031	0.605	-
Denmark	1.000	-	0.037	0.208	0.037
Estonia	1.000	-	0.001	0.114	0.027
Finland	1.000	-	0.002	0.313	0.068
France	1.000	0.859	0.032	0.080	0.333
Germany	1.000	0.836	0.139	0.847	0.983
Greece	1.000	0.830	0.023	0.092	0.031
Hungary	1.000	0.816	0.075	0.409	-
Ireland	1.000	-	0.003	0.112	0.011
Italy	1.000	0.563	0.059	0.340	0.327
Latvia	1.000	-	0.012	0.057	0.011
Lithuania	0.975	-	0.007	0.047	0.067
Netherlands	1.000	-	0.080	0.117	0.475
Poland	1.000	0.258	0.003	0.233	0.129
Portugal	0.978	0.246	0.017	0.299	0.117
Romania	1.000	0.712	0.011	0.073	0.097
Slovakia	1.000	0.268	0.011	0.531	-
Slovenia	1.000	-	0.837	1.000	-
Spain	1.000	0.577	0.019	0.147	0.162
Sweden	-	0.982	0.007	0.084	0.016
Switzerland	1.000	1.000	0.779	0.769	-
United Kingdom	0.757	-	0.106	0.377	0.041
Europe	0.917	1.000	0.036	0.276	0.111

Table C.8.5 – Shares [-] of the potential generation capacities that are installed for the best observed solutions *without curtailment*. The countries which need a generation capacity that is larger than the available potential are highlighted in red.

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C.9 The relevance of storage

Country	Generation share [-] Storage	Generation share [-] No Storage	Factor [-]	GWP100a [gCO_2eq/kWh] Storage	GWP100a [gCO_2eq/kWh] No Storage	Increase [%]
Austria	0.312	1.171	-	27.92	-	-
Belgium	1.351	47.834	-	152.16	-	-
Bulgaria	0.091	0.267	2.92	40.94	91.23	+123%
Czechia	0.324	3.132	-	55.66	-	-
Denmark	0.069	0.566	8.26	49.12	209.35	+326%
Estonia	0.047	0.201	4.32	40.24	95.71	+138%
Finland	0.109	0.348	3.19	34.49	69.44	+101%
France	0.147	0.351	2.39	37.19	54.33	+46%
Germany	0.542	5.916	-	54.86	-	-
Greece	0.060	0.142	2.37	40.32	64.69	+60%
Hungary	0.286	5.528	-	61.02	-	-
Ireland	0.038	0.186	4.88	41.88	89.91	+115%
Italy	0.225	0.471	2.09	34.91	51.46	+47%
Latvia	0.029	0.199	6.84	45.50	181.76	+300%
Lithuania	0.041	0.288	7.05	40.72	152.54	+275%
Netherlands	0.361	11.034	-	52.74	-	-
Poland	0.144	0.617	4.29	43.33	89.81	+107%
Portugal	0.121	0.269	2.23	35.48	51.78	+46%
Romania	0.063	0.133	2.11	40.57	65.02	+60%
Slovakia	0.231	0.465	2.02	27.63	37.22	+35%
Slovenia	0.891	21.910	-	84.81	-	-
Spain	0.097	0.226	2.34	37.48	60.09	+60%
Sweden	0.080	0.125	1.57	45.98	50.81	+10%
Switzerland	0.843	13.480	-	82.01	-	-
United Kingdom	0.133	0.524	3.94	44.55	103.02	+131%
Europe	0.171	0.351	2.05	35.94	54.33	+51%

Table C.9.1 – Comparison between solutions with and without storage. The results are shown in terms of electricity generation as share [-] of the potential. Solutions with a ratio that is greater than 1 (highlighted in red) are technically unattainable – there is not enough renewable potential to invest in generation over-capacity without installing any storage. The generation over-sizing factor [-] is included per country. The solutions are also compared in terms of Global Warming Potential (GWP100a).

C.10 Simulation results

Country	No. simulations	Best seed	LCOE [EUR/MWh]	GWP100a [gCO_2eq/kWh]
Austria	2995	2791	153.20	27.92
Belgium	2995	2914	281.87	152.16
Bulgaria	999	650	151.60	40.94
Czechia	999	546	192.91	55.66
Denmark	1014	177	203.96	49.12
Estonia	999	650	178.92	40.24
Finland	1997	1890	137.98	34.49
France	2677	1994	150.30	37.19
Germany	2868	329	182.84	54.86
Greece	999	329	140.24	40.32
Hungary	1636	25	243.58	61.02
Ireland	999	759	172.76	41.88
Italy	3154	1033	131.00	34.91
Latvia	999	394	225.03	45.50
Lithuania	999	650	162.83	40.72
Netherlands	3009	2791	208.67	52.74
Poland	2777	329	170.02	43.33
Portugal	999	329	137.42	35.48
Romania	2995	2791	134.47	40.57
Slovakia	1880	546	113.80	27.63
Slovenia	1999	1439	250.13	84.81
Spain	3020	329	139.31	37.48
Sweden	2664	75	73.89	45.98
Switzerland	1958	1157	198.59	82.01
United Kingdom	3262	2351	181.55	44.55
Europe *	-	-	164.99	47.54
Europe **	5048	4731	135.38	35.94

* Independent countries with isolated grids.
** Interconnected grids.

Table C.10.1 – Results of the simulations *without curtailment*. The Levelized Cost of Electricity (LCOE) [EUR/MWh] and the Global Warming Potential (GWP100a) [gCO_2eq/kWh] are given for the best observed seed, that is located at the knee of the Pareto front.

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	Generation [-]					Storage [-]	
Country	**H. RoR**	**H. Reservoir**	**PV**	**W. Onshore**	**W. Offshore**	**Battery**	**PtoG**
Austria	0.088	0.402	0.013	0.182	-	0.201	0.115
Belgium	0.001	-	0.455	0.067	0.057	0.315	0.105
Bulgaria	0.076	0.040	0.112	0.154	0.373	0.164	0.082
Czechia	0.005	0.007	0.033	0.528	-	0.281	0.146
Denmark	0.000	-	0.051	0.274	0.294	0.250	0.130
Estonia	0.001	-	0.002	0.396	0.249	0.240	0.113
Finland	0.040	-	0.001	0.221	0.439	0.185	0.113
France	0.021	0.053	0.058	0.136	0.452	0.166	0.113
Germany	0.005	0.019	0.096	0.306	0.280	0.174	0.120
Greece	0.000	0.151	0.070	0.295	0.148	0.235	0.100
Hungary	0.001	0.008	0.076	0.416	-	0.359	0.141
Ireland	0.005	-	0.009	0.437	0.134	0.259	0.155
Italy	0.086	0.029	0.102	0.227	0.323	0.145	0.088
Latvia	0.098	-	0.041	0.289	0.125	0.343	0.105
Lithuania	0.014	-	0.040	0.365	0.170	0.279	0.132
Netherlands	0.000	-	0.027	0.029	0.535	0.259	0.150
Poland	0.005	0.007	0.006	0.450	0.125	0.258	0.148
Portugal	0.065	0.074	0.037	0.261	0.303	0.153	0.107
Romania	0.045	0.181	0.055	0.200	0.264	0.162	0.093
Slovakia	0.048	0.058	0.028	0.666	-	0.110	0.090
Slovenia	0.044	-	0.377	0.112	-	0.279	0.189
Spain	0.025	0.084	0.054	0.406	0.178	0.154	0.099
Sweden	-	0.353	0.008	0.228	0.201	0.131	0.078
Switzerland	0.047	0.094	0.382	0.127	-	0.228	0.122
United Kingdom	0.007	-	0.081	0.334	0.191	0.272	0.115
Europe *	0.023	0.053	0.081	0.270	0.257	0.200	0.114
Europe **	0.024	0.076	0.060	0.383	0.261	0.118	0.078

* Independent countries with isolated grids.

** Interconnected grids.

Table C.10.2 – Contributions [-] of generation and storage technologies to the Levelized Cost of Electricity (LCOE) [EUR/MWh] of the whole energy system. Results of the best observed solutions *without curtailment*.

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Country	Generation [-]					Storage [-]		Total [-]
	H. RoR	H. Reservoir	PV	W. Onshore	W. Offshore	Battery	PtoG	
Austria	0.080	0.394	0.008	0.137	-	0.112	0.149	0.879
Belgium	0.001	-	0.298	0.052	0.043	0.102	0.289	0.784
Bulgaria	0.069	0.039	0.073	0.118	0.283	0.080	0.155	0.818
Czechia	0.005	0.006	0.021	0.402	-	0.143	0.266	0.842
Denmark	0.000	-	0.033	0.207	0.223	0.127	0.236	0.827
Estonia	0.001	-	0.001	0.303	0.189	0.110	0.225	0.828
Finland	0.037	-	0.001	0.164	0.333	0.110	0.171	0.815
France	0.019	0.051	0.038	0.103	0.343	0.110	0.158	0.823
Germany	0.005	0.018	0.063	0.235	0.212	0.117	0.163	0.813
Greece	0.000	0.147	0.046	0.221	0.113	0.097	0.172	0.796
Hungary	0.001	0.007	0.050	0.316	-	0.137	0.335	0.846
Ireland	0.005	-	0.006	0.328	0.102	0.151	0.245	0.836
Italy	0.078	0.026	0.067	0.175	0.245	0.086	0.121	0.798
Latvia	0.090	-	0.027	0.220	0.095	0.102	0.258	0.791
Lithuania	0.013	-	0.026	0.271	0.129	0.128	0.261	0.828
Netherlands	0.000	-	0.018	0.022	0.406	0.146	0.245	0.837
Poland	0.005	0.007	0.004	0.338	0.095	0.144	0.244	0.836
Portugal	0.059	0.073	0.024	0.195	0.230	0.105	0.143	0.829
Romania	0.040	0.177	0.036	0.152	0.200	0.091	0.153	0.849
Slovakia	0.044	0.058	0.018	0.505	-	0.088	0.103	0.815
Slovenia	0.040	-	0.246	0.088	-	0.184	0.213	0.771
Spain	0.023	0.082	0.035	0.309	0.135	0.096	0.146	0.827
Sweden	-	0.332	0.005	0.171	0.153	0.076	0.094	0.832
Switzerland	0.043	0.091	0.250	0.098	-	0.119	0.209	0.810
United Kingdom	0.006	-	0.053	0.250	0.145	0.112	0.200	0.767
Europe *	0.021	0.051	0.053	0.205	0.195	0.111	0.177	0.815
Europe **	0.022	0.073	0.039	0.294	0.198	0.076	0.110	0.811

* Independent countries with isolated grids.

** Interconnected grids.

Table C.10.3 – Contribution of capital costs [-] to the system Levelized Cost Of Electricity (LCOE). Results of the best observed solutions *without curtailment.*

C

	No curtailment		Curtailment	
Country	**Battery [-]**	**Power-to-gas [-]**	**Battery [-]**	**Power-to-gas [-]**
Austria	0.032	0.187	0.022	0.119
Belgium	0.177	0.314	0.174	0.305
Bulgaria	0.034	0.131	0.023	0.111
Czechia	0.052	0.299	0.038	0.238
Denmark	0.052	0.282	0.051	0.280
Estonia	0.042	0.214	0.034	0.193
Finland	0.028	0.166	0.024	0.153
France	0.024	0.181	0.022	0.177
Germany	0.037	0.233	0.036	0.233
Greece	0.024	0.148	0.019	0.123
Hungary	0.079	0.364	0.065	0.272
Ireland	0.044	0.284	0.036	0.249
Italy	0.022	0.122	0.017	0.110
Latvia	0.051	0.250	0.032	0.199
Lithuania	0.051	0.227	0.042	0.199
Netherlands	0.053	0.332	0.049	0.325
Poland	0.047	0.267	0.038	0.233
Portugal	0.025	0.157	0.020	0.130
Romania	0.024	0.133	0.023	0.121
Slovakia	0.017	0.109	0.013	0.094
Slovenia	0.130	0.150	0.136	0.183
Spain	0.020	0.146	0.015	0.122
Sweden	0.010	0.061	0.008	0.055
Switzerland	0.091	0.257	0.062	0.195
United Kingdom	0.039	0.221	0.027	0.184
Europe *	0.038	0.203	0.033	0.185
Europe **	0.022	0.112	0.018	0.100

* Independent countries with isolated grids.

** Interconnected grids.

Table C.10.4 – Shares [-] of electricity demand that is lost due to storage inefficiencies. Results for the best observed solutions *with* and *without curtailment*.

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Country	Capacity [GWh]	Partial cycles	Average DoD [-]	Capacity factor [-]		
				1-hour	4-hours	24-hours
Austria	69	712	0.172	0.014	0.056	0.335
Belgium	329	430	0.438	0.022	0.086	0.516
Bulgaria	36	617	0.202	0.014	0.057	0.341
Czechia	166	608	0.144	0.010	0.040	0.239
Denmark	85	513	0.182	0.011	0.043	0.255
Estonia	17	563	0.161	0.010	0.041	0.248
Finland	82	503	0.202	0.012	0.046	0.278
France	497	593	0.146	0.010	0.040	0.237
Germany	781	569	0.188	0.012	0.049	0.293
Greece	53	748	0.113	0.010	0.039	0.233
Hungary	184	626	0.133	0.010	0.038	0.229
Ireland	59	495	0.183	0.010	0.041	0.248
Italy	232	645	0.188	0.014	0.055	0.331
Latvia	25	687	0.110	0.009	0.034	0.206
Lithuania	28	567	0.183	0.012	0.047	0.284
Netherlands	273	614	0.145	0.010	0.041	0.244
Poland	365	471	0.208	0.011	0.045	0.269
Portugal	41	626	0.175	0.012	0.050	0.300
Romania	58	597	0.167	0.011	0.045	0.273
Slovakia	16	627	0.200	0.014	0.057	0.344
Slovenia	32	516	0.411	0.024	0.097	0.581
Spain	218	583	0.145	0.010	0.039	0.232
Sweden	38	688	0.183	0.014	0.058	0.346
Switzerland	116	478	0.395	0.022	0.086	0.518
United Kingdom	569	741	0.125	0.011	0.042	0.255
Europe	2106	511	0.249	0.015	0.058	0.349

Table C.10.5 – Battery design and operating characteristics by country and all Europe. Results for solutions *without curtailment*. The average depth of discharge (DoD) is the mean share [-] of battery capacity that is discharged during each partial cycle. The capacity factor represents the average amount of energy, calculated as share [-] of battery capacity, stored at different time intervals (from 1 hour to 24 hours).

(Chapter 4)

D.1 Data uncertainty

	Technology	Distribution	min	median [1]	max	Parameters				p-value
						p1	p2	p3	p4	
Capital fixed	Hydro Run-of-River	Power-function	945.00	2250.00	8000.00	0.47	945.00	7126.46	-	0.985
	Hydro Reservoir	Power-function	500.00	1852.00	4800.00	0.90	97.59	4702.42	-	0.732
	Solar Photovoltaic	Normal	482.00	934.00	1988.00	1010.06	448.88	-	-	0.673
	Wind Onshore	Normal	1400.00	1743.50	2506.00	1783.21	289.50	-	-	0.619
	Wind Offshore	Normal	3800.00	3947.00	4094.00	3947.00	147.00	-	-	0.933
Maintenance fixed	Hydro Run-of-River	Chi-squared	9.88	18.00	130.00	1.02	9.88	26.03	-	0.768
	Hydro Reservoir	Log-normal	8.77	19.93	90.00	1.11	7.66	12.13	-	0.685
	Solar Photovoltaic	GEV	24.10	46.70	99.40	-0.19	39.00	14.74	-	0.999
	Wind Onshore	Normal	31.72	33.36	54.00	38.79	8.54	-	-	0.198
	Wind Offshore	Normal	114.00	118.41	122.82	118.41	4.41	-	-	0.933
Maintenance variable	Hydro Run-of-River	Beta	0.00	0.95	5.54	0.32	0.61	-0.22	5.76	0.616
	Hydro Reservoir	GEV	1.60	2.46	5.94	-0.30	2.41	0.79	-	0.699
	Solar Photovoltaic	-	-	-	-	-	-	-	-	-
	Wind Onshore	Normal	6.34	8.46	10.57	8.46	1.73	-	-	0.868
	Wind Offshore	-	-	-	-	-	-	-	-	-

[1] Medians from Table C.3.1.

Table D.1.1 – Probability distributions used to draw the specific costs (Capital and Maintenance) associated with the generation technologies. The distributions are identified comparing the cost data with a set of reference distributions (null hypothesis in statistical testing) using the Kolmogorov-Smirnov test. The one that maximises the p-value is selected as the best fit. The cost variables are assumed to be continuous and random. The tested distributions are: Normal, Log-normal, Chi, Chi-squared, Exponentiated Weibull, Weibull maximum, Weibull minimum, Pareto Type II or Lomax, Generalized Extreme Value (GEV), Power-function, Power Log-normal, Power Normal, Beta and Uniform. The minimum and maximum values are used to accept or reject the drawn samples. Use Table C.3.1 for the unit of measurement of the different cost sources.

	Storage	Technology	Distribution	min	median [1]	max	p1	p2	p3	p4	p-value
							Parameters				
Capital fixed	Battery	Lead-acid	Power-Normal	120.00	250.00	291.00	49122.31	1249.50	242.80	-	0.934
		Lithium-ion	Chi-squared	223.00	377.50	780.00	4.18	204.32	49.64	-	0.999
		Vanadium flow	Lomax	340.00	403.00	819.00	3.94	-0.55	340.55	-	0.778
		Zinc flow	Power-function	381.00	492.50	616.00	0.75	381.00	246.45	-	0.956
	PtoG	SNG	-	-	-	-	-	-	-	-	-
		Hydrogen	-	-	-	-	-	-	-	-	-
Capital variable	Battery	Lead-acid	-	-	-	-	-	-	-	-	-
		Lithium-ion	-	-	-	-	-	-	-	-	-
		Vanadium flow	-	-	-	-	-	-	-	-	-
		Zinc flow	-	-	-	-	-	-	-	-	-
	PtoG	SNG	GEV	0.0292	0.0695	0.1105	0.374	0.060	0.025	-	0.993
		Hydrogen	Lomax	0.1246	0.1790	0.6988	2.370	-0.039	0.164	-	0.918
Maintenance fixed	Battery	Lead-acid	Uniform	3.97	9.93	26.49	-	-	-	-	-
		Lithium-ion	Weibull min.	6.00	15.00	40.00	0.91	6.00	15.35	-	0.603
		Vanadium flow	Uniform	6.41	16.01	42.70	-	-	-	-	-
		Zinc flow	Uniform	7.83	19.57	52.19	-	-	-	-	-
	PtoG	SNG	-	-	-	-	-	-	-	-	-
		Hydrogen	-	-	-	-	-	-	-	-	-
Maintenance variable	Battery	Lead-acid	Uniform	0.00	0.13	4.64	-	-	-	-	-
		Lithium-ion	Normal	0.00	0.20	7.00	1.68	2.53	-	-	0.235
		Vanadium flow	Uniform	0.00	0.21	7.47	-	-	-	-	-
		Zinc flow	Uniform	0.00	0.26	9.13	-	-	-	-	-
	PtoG	SNG	Uniform	0.0015	0.0035	0.0055	-	-	-	-	-
		Hydrogen	Uniform	0.0062	0.0089	0.0349	-	-	-	-	-

[1] Medians from Table C.3.2.

Table D.1.2 – Probability distributions used to draw the specific costs (Capital and Maintenance) associated with the storage. The distributions are identified using the Kolmogorov-Smirnov test (see description Table D.1.1). Use Table C.3.2 for the unit of measurement of the different cost sources.

Storage	Technology	Charge efficiency [-] min	Charge efficiency [-] median	Charge efficiency [-] max	Discharge efficiency [-] min	Discharge efficiency [-] median	Discharge efficiency [-] max	No. cycles min	No. cycles median	No. cycles max
Battery	Lead-acid	0.894	0.917	0.980	0.894	0.917	0.980	500	750	1000
	Lithium-ion	0.894	0.917	0.980	0.894	0.917	0.980	1000	5500	10000
	Vanadium flow	0.806	0.837	0.866	0.806	0.837	0.866	12000	13000	14000
	Zinc flow	0.806	0.837	0.866	0.806	0.837	0.866	12000	13000	14000
PtoG	SNG	0.500	0.567	0.633	0.600	0.600	0.600	-	-	-
	Hydrogen	0.583	0.667	0.750	0.600	0.600	0.600	-	-	-

Table D.1.3 – Charge and discharge efficiency of the long- [158] and short-term [111] storage and number of cycles of batteries before replacement [114, 115].

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	Reliability	Completeness	Temporal correlation	Geographical correlation	Technological correlation
Pedigree [1]	3	2	3	3	2
Additional uncertainty sources	0.00	0.0006	0.002	0.008	0.04
	0.00	0.0001	0.0006	0.002	0.08
	0.00	0.0002	0.002	0.008	0.04
	0.00	0.000025	0.0001	0.0006	0.002
	0.00	0.0006	0.008	0.04	0.12

[1] Common Pedigree for electricity generation technologies.

Table D.1.4 – Pedigree matrix [-] and uncertainty sources [-] used to draw from the assumed log-normal distribution of the impact factors associated with electricity generation [41]. The total variance of the log-transformed data is calculated by summing up the basic uncertainty (0.0006 for electricity) and the additional contribution that is obtained from the pedigree matrix.

D.2 Electrical synergy results

	Independent grids		Interconnected grids	
Indicator	**Value**	**Baseline**	**Value**	**Deviation**
Generation capacity [GW]	2454	100%	2400	-2.18%
Total annual generation [TWh]	5469	100%	4996	-8.64%
Stored electricity (battery) [TWh]	560	100%	320	-42.78%
Storage capacity (battery) [TWh]	4.37	100%	2.11	-51.82%
Stored electricity (power-to-gas) [TWh]	1355	100%	748	-44.81%
Storage capacity (power-to-gas) [TWh]	289	100%	160	-44.67%
LCOE [EUR/MWh]	165.00	100%	135.38	-17.95%
GWP100a [gCO_2eq/kWh]	47.54	100%	35.94	-24.41%

Table D.2.1 – Comparison between aggregated results of independent countries with isolated grids (baseline at 100%) and interconnected scenario. The relative improvements are expressed in terms of percentage deviation from the baseline.

Country	LCOE		GWP100a	
	Difference [EUR/MWh]	Deviation [%]	Difference [gCO_2eq/kWh]	Deviation [%]
Austria	17.83	+13.17%	-8.01	-22.30%
Belgium	146.50	+108.22%	116.22	+323.41%
Bulgaria	16.22	+11.98%	5.00	+13.91%
Czechia	57.54	+42.50%	19.72	+54.88%
Denmark	68.58	+50.66%	13.18	+36.68%
Estonia	43.54	+32.16%	4.30	+11.96%
Finland	2.61	+1.92%	-1.45	-4.02%
France	14.92	+11.02%	1.25	+3.48%
Germany	47.46	+35.06%	18.92	+52.65%
Greece	4.87	+3.59%	4.38	+12.19%
Hungary	108.20	+79.93%	25.08	+69.79%
Ireland	37.38	+27.61%	5.95	+16.55%
Italy	-4.37	-3.23%	-1.03	-2.86%
Latvia	89.65	+66.23%	9.56	+26.60%
Lithuania	27.45	+20.28%	4.79	+13.32%
Netherlands	73.29	+54.14%	16.80	+46.75%
Poland	34.64	+25.59%	7.40	+20.58%
Portugal	2.05	+1.51%	-0.45	-1.27%
Romania	-0.91	-0.67%	4.63	+12.89%
Slovakia	-21.57	-15.94%	-8.31	-23.11%
Slovenia	114.75	+84.77%	48.87	+135.99%
Spain	3.94	+2.91%	1.54	+4.29%
Sweden	-61.49	-45.42%	10.05	+27.96%
Switzerland	63.22	+46.70%	46.08	+128.22%
United Kingdom	46.17	+34.11%	8.61	+23.97%

Table D.2.2 – Difference between isolated and interconnected grids LCOE [EUR/MWh] and GWP100a [gCO_2eq/kWh] by country. A positive ΔLCOE represents a reduction in the price of electricity. Conversely, a negative value corresponds to an increase of the electricity cost. The difference in the GWP100a represents the amount of equivalent carbon emissions per kWh of consumed electricity that would be avoided (positive) by each country if joining the European grid. The changes in costs and emissions are also reported in terms of relative deviations from the interconnected case.

D.3 Uncertainty analysis results

Country	Uncertainty analysis		Selected design		LCOE	GWP100a
	Pareto eff. solutions	No. of evaluations	Battery	PtoG	[EUR/MWh]	[gCO_2eq/kWh]
Austria	8	40008	Vanadium flow	Hydrogen	213.26	26.60
Belgium	5	25005	Lithium-ion	SNG	287.22	157.85
Bulgaria	6	30006	Vanadium flow	SNG	169.52	40.69
Czechia	15	75015	Vanadium flow	SNG	192.77	62.96
Denmark	30	150030	Vanadium flow	SNG	217.38	49.68
Estonia	7	35007	Zinc flow	SNG	186.78	40.18
Finland	51	255051	Vanadium flow	SNG	143.27	36.20
France	8	40008	Vanadium flow	SNG	156.02	39.75
Germany	17	85017	Zinc flow	SNG	196.76	55.74
Greece	14	70014	Zinc flow	SNG	138.52	45.50
Hungary	41	205041	Vanadium flow	SNG	237.86	69.47
Ireland	9	45009	Vanadium flow	SNG	180.21	42.86
Italy	9	45009	Vanadium flow	SNG	139.90	35.83
Latvia	4	20004	Vanadium flow	SNG	229.80	45.73
Lithuania	4	20004	Vanadium flow	SNG	169.03	44.12
Netherlands	178	890178	Zinc flow	SNG	219.50	53.60
Poland	16	80016	Vanadium flow	SNG	174.00	47.95
Portugal	20	100020	Zinc flow	SNG	141.04	39.41
Romania	4	20004	Vanadium flow	SNG	150.45	40.95
Slovakia	2	10002	Vanadium flow	SNG	125.29	27.81
Slovenia	4	20004	Vanadium flow	SNG	238.56	92.89
Spain	22	110022	Zinc flow	SNG	155.50	37.97
Sweden	43	215043	Vanadium flow	SNG	94.88	43.40
Switzerland	3	15003	Vanadium flow	SNG	222.06	82.64
United Kingdom	16	80016	Zinc flow	SNG	194.08	44.02
Europe	10	50010	Zinc flow	SNG	151.19	36.08

Table D.3.1 – Best storage system design by country after uncertainty analysis of the Pareto-efficient solutions *without curtailment*. The mean Levelized Cost of Electricity (LCOE) [EUR/MWh] and Global Warming Potential (GWP100a) [gCO_2eq/kWh] are shown for each energy system design.

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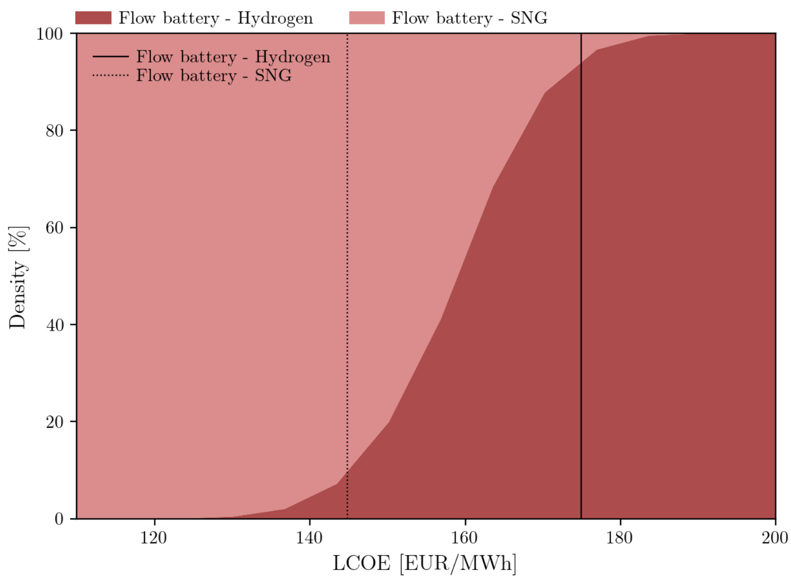

Figure D.3.1 – Solution density [%] of power-to-gas storage with flow battery as a function of the Levelized Cost of Electricity (LCOE) [EUR/MWh] for interconnected grids. The vertical lines are the median values of the distributions. (Table D.3.2)

LCOE [EUR/MWh]	**Hydrogen [%]**	**SNG [%]**
... - 127	0.00	100.00
127 - 133	0.41	99.59
133 - 140	2.00	98.00
140 - 147	7.18	92.82
147 - 153	19.91	80.09
153 - 160	41.12	58.88
160 - 167	68.35	31.65
167 - 174	87.81	12.19
174 - 180	96.63	3.37
180 - 187	99.51	0.49
187 - ...	100.00	0.00

Table D.3.2 – Density of solutions with hydrogen and SNG storage for different intervals of Levelized Cost of Electricity (LCOE) [EUR/MWh]. Results for interconnected grids.

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GWP100a [gCO_2eq/kWh]	**Hydrogen [%]**	**SNG [%]**
... - 29.06	100.00	0.00
29.06 - 30.11	96.76	3.24
30.11 - 31.15	95.66	4.34
31.15 - 32.20	90.15	9.85
32.20 - 33.25	84.38	15.62
33.25 - 34.29	75.18	24.82
34.29 - 35.34	63.96	36.04
35.34 - 36.38	51.86	48.14
36.38 - 37.43	39.62	60.38
37.43 - 38.48	27.26	72.74
38.48 - 39.52	17.85	82.15
39.52 - 40.57	11.47	88.53
40.57 - 41.61	7.27	92.73
41.61 - 42.66	4.27	95.73
42.66 - 43.71	1.43	98.57
43.71 - 44.75	1.01	98.99
44.75 - 45.80	0.57	99.43
45.80 - ...	0.00	100.00

Table D.3.3 – Density of solutions with hydrogen and SNG storage for different intervals of Global Warming Potential (GWP100a) [gCO_2eq/KWh]. Results for interconnected grids.

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D.4 Capacity requirements of storage

	Δ LCOE [-]	Δ GWP100a [-]
Country	**Hydrogen**	**Hydrogen**
Austria	0.199	-0.172
Belgium	0.145	-0.083
Bulgaria	0.188	-0.111
Czechia	0.276	-0.170
Denmark	0.203	-0.112
Estonia	0.169	-0.103
Finland	0.173	-0.092
France	0.189	-0.110
Germany	0.187	-0.112
Greece	0.216	-0.146
Hungary	0.272	-0.165
Ireland	0.239	-0.112
Italy	0.192	-0.079
Latvia	0.214	-0.135
Lithuania	0.269	-0.159
Netherlands	0.229	-0.139
Poland	0.253	-0.136
Portugal	0.218	-0.126
Romania	0.191	-0.051
Slovakia	-	-
Slovenia	0.108	-0.080
Spain	0.212	-0.135
Sweden	0.275	-0.077
Switzerland	0.173	-0.084
United Kingdom	0.249	-0.120
Europe	0.209	-0.113
Europe	0.185	-0.078

Table D.4.1 – Mean relative deviation [-] in the LCOE and GWP100a of the Pareto-efficient uncertain solutions obtained for the power-to-hydrogen storage with respect to SNG (reference).

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	Δ LCOE [-]			Δ GWP100a [-]		
Country	**Lead-cid**	**Lithium-ion**	**Zinc flow**	**Lead-cid**	**Lithium-ion**	**Zinc flow**
Austria	-	-	0.017	-	-	0.004
Belgium	-	-0.041	0.030	-	0.027	0.002
Bulgaria	-	-	-	-	-	-
Czechia	-	-	-	-	-	-
Denmark	-	-	0.050	-	-	-0.021
Estonia	-	-	0.020	-	-	-0.049
Finland	-	-	0.047	-	-	-0.042
France	-	-	-	-	-	-
Germany	-	-	0.027	-	-	-0.056
Greece	-	-	-0.015	-	-	-0.001
Hungary	-	-	0.157	-	-	-0.084
Ireland	-	-	0.036	-	-	-0.009
Italy	-	-	-0.023	-	-	0.016
Latvia	-	-	0.038	-	-	-0.008
Lithuania	-	-	-	-	-	-
Netherlands	-	-	0.059	-	-	-0.076
Poland	-	-	0.028	-	-	-0.030
Portugal	-	-	0.004	-	-	0.003
Romania	-	-	-	-	-	-
Slovakia	-	-	-	-	-	-
Slovenia	-	-	0.032	-	-	0.014
Spain	-	-	0.082	-	-	-0.082
Sweden	-	-	0.055	-	-	-0.017
Switzerland	-	-	0.020	-	-	-0.004
United Kingdom	-	-	0.063	-	-	-0.035
Europe	-	-0.041	0.036	-	0.027	-0.034
Europe	-	-	0.013	-	-	-0.020

Table D.4.2 – Mean relative deviation [-] in the LCOE and GWP100a of the Pareto uncertain solutions obtained for the different battery technologies with respect to the reference one (Vanadium flow). The results are shown only for the battery technologies that are Pareto-efficient.

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Country	Technology	Storage capacity [-]				
		L. Whisker	Q1	Q2	Q3	H. Whisker
Austria	Hydrogen	0.112	0.122	0.130	0.138	0.149
Belgium	SNG	0.224	0.240	0.254	0.269	0.284
Bulgaria	SNG	0.031	0.037	0.042	0.050	0.061
Czechia	SNG	0.054	0.063	0.067	0.072	0.093
Denmark	SNG	0.040	0.046	0.050	0.059	0.107
Estonia	SNG	0.047	0.050	0.053	0.056	0.060
Finland	SNG	0.040	0.047	0.050	0.053	0.060
France	SNG	0.049	0.057	0.061	0.065	0.073
Germany	SNG	0.053	0.056	0.060	0.063	0.067
Greece	SNG	0.034	0.037	0.039	0.042	0.045
Hungary	SNG	0.067	0.084	0.099	0.111	0.144
Ireland	SNG	0.063	0.069	0.073	0.078	0.085
Italy	SNG	0.034	0.043	0.047	0.050	0.058
Latvia	SNG	0.054	0.057	0.061	0.064	0.068
Lithuania	SNG	0.041	0.046	0.052	0.059	0.066
Netherlands	SNG	0.051	0.055	0.059	0.062	0.066
Poland	SNG	0.041	0.045	0.048	0.051	0.060
Portugal	SNG	0.039	0.042	0.044	0.047	0.049
Romania	SNG	0.069	0.073	0.078	0.082	0.087
Slovakia	SNG	0.038	0.040	0.043	0.045	0.048
Slovenia	SNG	0.111	0.118	0.126	0.133	0.141
Spain	SNG	0.045	0.048	0.051	0.054	0.057
Sweden	SNG	0.027	0.030	0.032	0.034	0.038
Switzerland	SNG	0.180	0.192	0.204	0.216	0.228
United Kingdom	SNG	0.045	0.050	0.053	0.056	0.062
Europe	SNG	0.031	0.033	0.035	0.037	0.039

Table D.4.3 – Power-to-gas capacity distributions calculated as share [-] of the annual electricity demand for the best observed long-term storage technology in each country. Uncertainty analysis results for the solutions *without curtailment*. The lower and higher whiskers correspond to the minimum and maximum capacity, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distribution.

Country	Technology	Storage capacity [-]				
		L. Whisker	**Q1**	**Q2**	**Q3**	**H. Whisker**
Austria	Vanadium flow	0.00077	0.00083	0.00085	0.00087	0.00093
Belgium	Lithium-ion	0.00245	0.00261	0.00268	0.00275	0.00292
Bulgaria	Vanadium flow	0.00071	0.00077	0.00079	0.00082	0.00089
Czechia	Vanadium flow	0.00132	0.00142	0.00146	0.00151	0.00177
Denmark	Vanadium flow	0.00133	0.00148	0.00154	0.00160	0.00176
Estonia	Zinc flow	0.00111	0.00117	0.00119	0.00122	0.00128
Finland	Vanadium flow	0.00068	0.00073	0.00075	0.00077	0.00085
France	Vanadium flow	0.00063	0.00074	0.00078	0.00082	0.00090
Germany	Zinc flow	0.00092	0.00097	0.00099	0.00101	0.00106
Greece	Zinc flow	0.00057	0.00061	0.00062	0.00064	0.00068
Hungary	Vanadium flow	0.00158	0.00189	0.00204	0.00227	0.00307
Ireland	Vanadium flow	0.00123	0.00131	0.00134	0.00137	0.00146
Italy	Vanadium flow	0.00048	0.00051	0.00052	0.00053	0.00057
Latvia	Vanadium flow	0.00175	0.00188	0.00196	0.00205	0.00219
Lithuania	Vanadium flow	0.00121	0.00129	0.00133	0.00137	0.00147
Netherlands	Zinc flow	0.00152	0.00161	0.00165	0.00168	0.00178
Poland	Vanadium flow	0.00093	0.00108	0.00116	0.00124	0.00143
Portugal	Zinc flow	0.00054	0.00056	0.00057	0.00059	0.00062
Romania	Vanadium flow	0.00062	0.00065	0.00066	0.00068	0.00071
Slovakia	Vanadium flow	0.00035	0.00037	0.00038	0.00039	0.00041
Slovenia	Vanadium flow	0.00172	0.00180	0.00184	0.00188	0.00197
Spain	Zinc flow	0.00065	0.00068	0.00070	0.00071	0.00075
Sweden	Vanadium flow	0.00021	0.00026	0.00031	0.00036	0.00048
Switzerland	Vanadium flow	0.00125	0.00131	0.00134	0.00137	0.00144
United Kingdom	Zinc flow	0.00112	0.00119	0.00122	0.00124	0.00132
Europe	Zinc flow	0.00045	0.00048	0.00049	0.00050	0.00052

Table D.4.4 – Battery capacity distributions calculated as share [-] of the annual electricity demand for the best observed short-term storage technology in each country. Uncertainty analysis results for the solutions *without curtailment*. The lower and higher whiskers correspond to the minimum and maximum capacity, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distribution.

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Country	Average power demand [MW]	Battery Peak discharge power [MW]	Battery Duration [hours] [1]	Battery Duration [hours] [2]	P2G Peak discharge power [MW]	P2G Duration [days] [1]	P2G Duration [days] [2]
Austria	10721	6497	6	10	9677	29	32
Belgium	14312	30659	22	10	23370	56	34
Bulgaria	5454	3504	6	9	4924	9	10
Czechia	11501	14568	11	8	16733	15	10
Denmark	6261	8374	11	8	8065	11	8
Estonia	1478	1753	9	7	2382	12	7
Finland	12308	7817	5	9	12870	11	10
France	74268	48679	6	9	85200	13	12
Germany	93076	72097	7	9	152576	13	8
Greece	7812	5482	5	7	6382	9	11
Hungary	7981	18933	15	6	14905	22	12
Ireland	4983	5993	10	8	4724	16	17
Italy	51583	21547	4	9	49185	10	11
Latvia	1509	1978	14	11	2003	13	10
Lithuania	2336	2349	10	10	3770	11	7
Netherlands	18892	21380	12	11	30613	13	8
Poland	31218	37335	8	7	40089	11	8
Portugal	7350	4025	4	8	3726	10	19
Romania	10028	5588	5	9	8426	17	20
Slovakia	4811	1688	3	8	4993	9	9
Slovenia	2142	3175	14	9	2450	28	24
Spain	38096	21972	5	9	25982	11	16
Sweden	19539	4490	2	10	10147	7	13
Switzerland	9869	10536	10	9	9400	45	47
United Kingdom	55432	59503	9	8	68428	12	9
Europe *	502961	419920	7	9	601019	14	12
Europe **	502961	214087	4	8	430088	8	9

* Independent countries with isolated grids.

** Interconnected grids.

[1] Calculated using the country average power demand.

[2] Calculated using the peak discharge power.

Table D.4.5 – Grid reliability contribution of electricity storage as maximum duration of discharge. Solutions *without curtailment*. The duration is calculated assuming a fully charged storage and using the medians of the capacity distributions from Tables D.4.3 and D.4.4.

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D.5 Curtailments results

		Generation		Storage	
Country	**Factor [-]**	**Total [-]**	**Deviation [%]**	**Capacity [-]**	**Deviation [%]**
Austria	0.75	1.32	+8.15%	0.10	-29.19%
Belgium	0.36	1.54	+3.21%	0.24	-3.02%
Bulgaria	0.71	1.21	+3.67%	0.03	-25.35%
Czechia	0.71	1.55	+14.61%	0.05	-25.44%
Denmark	0.36	1.34	+0.45%	0.05	-2.04%
Estonia	0.37	1.23	-1.84%	0.05	+2.31%
Finland	0.59	1.22	+2.54%	0.04	-9.54%
France	0.59	1.28	+6.47%	0.05	-3.71%
Germany	0.33	1.29	+1.20%	0.06	-2.71%
Greece	0.71	1.23	+4.82%	0.03	-15.53%
Hungary	0.66	1.48	+2.51%	0.08	+1.53%
Ireland	0.54	1.41	+6.46%	0.06	-18.17%
Italy	0.71	1.20	+4.59%	0.04	-22.13%
Latvia	0.37	1.25	-4.21%	0.06	-11.51%
Lithuania	0.59	1.36	+6.54%	0.04	-7.83%
Netherlands	0.33	1.42	+2.24%	0.06	-5.20%
Poland	0.54	1.39	+5.76%	0.04	-18.14%
Portugal	0.71	1.24	+5.11%	0.06	-19.67%
Romania	0.59	1.18	+2.15%	0.07	-8.61%
Slovakia	0.71	1.16	+2.97%	0.04	-16.38%
Slovenia	0.62	1.32	+3.17%	0.12	-5.25%
Spain	0.71	1.21	+4.18%	0.04	-22.78%
Sweden	0.76	1.10	+2.99%	0.03	-13.47%
Switzerland	0.43	1.28	-4.69%	0.19	-6.44%
United Kingdom	0.68	1.37	+9.04%	0.05	-11.89%
Europe	0.70	1.16	+2.22%	0.03	-6.41%

Table D.5.1 – Annual generation and storage capacity of the best LCOE/GWP100a trade-off point as fraction [-] of the annual electricity demand. The relative deviation is given with respect to the best observed solution *without curtailment*.

Country	Factor [-]	Generation		Storage	
		Total [-]	Deviation [%]	Capacity [-]	Deviation [%]
Austria	0.66	1.24	+1.80%	0.127	-5.56%
Belgium	0.31	1.45	-2.78%	0.254	+2.71%
Bulgaria	0.83	1.28	+10.18%	0.026	-42.81%
Czechia	0.48	1.31	-2.79%	0.062	-2.17%
Denmark	0.83	1.48	+10.72%	0.037	-26.59%
Estonia	0.72	1.31	+4.47%	0.051	-4.68%
Finland	0.72	1.25	+4.66%	0.042	-13.25%
France	0.83	1.48	+23.15%	0.045	-20.09%
Germany	0.64	1.34	+5.84%	0.063	+2.29%
Greece	0.83	1.32	+12.98%	0.025	-29.06%
Hungary	0.63	1.51	+4.62%	0.082	+1.71%
Ireland	0.72	1.63	+22.41%	0.056	-27.52%
Italy	0.83	1.29	+12.38%	0.032	-32.53%
Latvia	0.52	1.23	-5.08%	0.059	-6.32%
Lithuania	0.47	1.32	+3.52%	0.054	+14.02%
Netherlands	0.41	1.38	+0.01%	0.057	-5.58%
Poland	0.58	1.36	+3.54%	0.043	-16.88%
Portugal	0.83	1.31	+11.22%	0.051	-30.93%
Romania	0.47	1.16	-0.01%	0.062	-21.22%
Slovakia	0.71	1.16	+2.97%	0.036	-16.38%
Slovenia	0.41	1.28	-0.05%	0.130	-0.52%
Spain	0.83	1.28	+9.73%	0.035	-32.20%
Sweden	0.79	1.18	+9.70%	0.031	-4.11%
Switzerland	0.36	1.28	-5.35%	0.195	-4.99%
United Kingdom	0.63	1.30	+3.50%	0.057	-7.98%
Europe	0.83	1.27	+11.61%	0.028	-24.08%

Table D.5.2 – Annual generation and storage capacity of the cleanest scenario (lowest GWP100a) as fraction [-] of the annual electricity demand. The relative deviation is given with respect to the best observed solution *without curtailment*.

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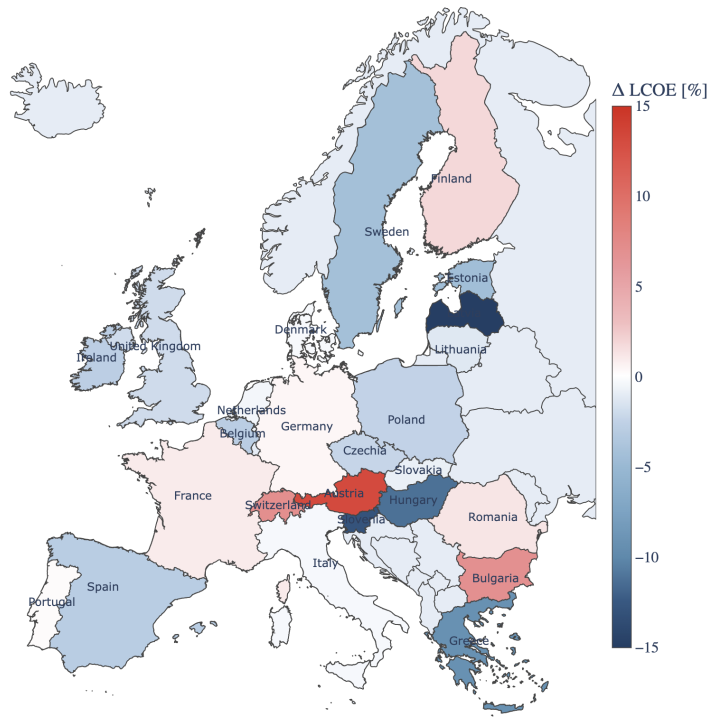
(a)



(b)

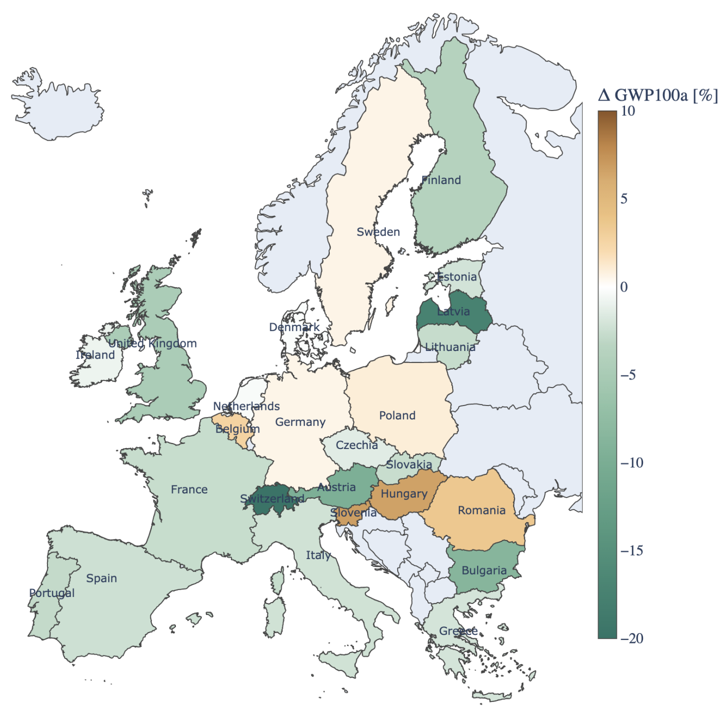


Figure D.5.1 – Percentage change in **(a)** LCOE and **(b)** GWP100a of the best curtailed solutions from the optimal scenario without curtailment (Table D.5.3). A negative ΔLCOE or ΔGWP100a highlight the countries that would either obtain a financial or environmental benefit when curtailing excess electricity.

Country	LCOE		GWP100a	
	Difference [EUR/MWh]	Change [%]	Difference [gCO_2eq/kWh]	Change [%]
Austria	19.98	+13.04%	-2.71	-9.69%
Belgium	-8.14	-2.89%	4.12	+2.71%
Bulgaria	10.51	+6.94%	-3.55	-8.66%
Czechia	-4.41	-2.28%	-0.82	-1.47%
Denmark	-0.69	-0.34%	-0.08	-0.16%
Estonia	-8.06	-4.50%	-0.87	-2.17%
Finland	2.51	+1.82%	-1.33	-3.86%
France	1.46	+0.97%	-1.01	-2.72%
Germany	0.75	+0.41%	0.31	+0.57%
Greece	-13.00	-9.27%	-0.84	-2.08%
Hungary	-27.35	-11.23%	4.04	+6.62%
Ireland	-4.86	-2.81%	-0.37	-0.88%
Italy	-0.49	-0.38%	-0.80	-2.30%
Latvia	-34.45	-15.31%	-7.92	-17.41%
Lithuania	-2.05	-1.26%	-1.13	-2.77%
Netherlands	-0.99	-0.47%	-0.18	-0.34%
Poland	-4.12	-2.43%	0.44	+1.01%
Portugal	0.27	+0.20%	-1.03	-2.90%
Romania	1.63	+1.21%	1.46	+3.59%
Slovakia	-0.96	-0.84%	-0.74	-2.66%
Slovenia	-32.46	-12.98%	5.82	+6.86%
Spain	-4.10	-2.94%	-0.91	-2.43%
Sweden	-3.17	-4.29%	0.28	+0.62%
Switzerland	13.96	+7.03%	-17.73	-21.62%
United Kingdom	-3.49	-1.92%	-2.16	-4.85%
Europe	-2.04	-1.51%	0.40	+1.12%

Table D.5.3 – Absolute difference and relative change in the Levelized Cost of Electricity (LCOE) and Global Warming Potential (GWP100a) of the best curtailed solutions from the optimal scenario *without curtailment*.

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Country	Curtailment factor [-]	Share of curtailed generation [1]	Max. LCOE reduction	Max. LCOE increase	Risk of worsening
Austria	0.84	48%	-22.1%	+15.1%	72%
Belgium	0.65	28%	-12.7%	+5.1%	23%
Bulgaria	0.82	32%	-17.3%	+18.7%	51%
Czechia	0.89	46%	-25.9%	+23.7%	67%
Denmark	0.84	33%	-21.2%	+5.8%	29%
Estonia	0.87	33%	-31.3%	+4.0%	10%
Finland	0.80	26%	-29.9%	+3.4%	20%
France	0.92	42%	-24.3%	+34.2%	73%
Germany	0.82	27%	-20.5%	+7.8%	45%
Greece	0.90	29%	-24.3%	+30.9%	52%
Hungary	0.87	38%	-22.8%	+24.9%	72%
Ireland	0.82	40%	-26.7%	+8.1%	78%
Italy	0.71	31%	-14.8%	+2.8%	5%
Latvia	0.82	40%	-27.1%	-3.8%	0%
Lithuania	0.84	39%	-27.7%	+5.4%	48%
Netherlands	0.64	22%	-17.6%	+7.6%	44%
Poland	0.58	11%	-21.5%	+0.4%	17%
Portugal	0.84	20%	-26.3%	+17.8%	53%
Romania	0.89	34%	-28.3%	+40.8%	64%
Slovakia	0.74	29%	-26.9%	+11.6%	3%
Slovenia	0.79	10%	-9.7%	-7.4%	0%
Spain	0.92	31%	-31.7%	+23.9%	52%
Sweden	0.89	28%	-22.9%	+4.8%	30%
Switzerland	0.64	26%	-19.0%	+2.1%	25%
United Kingdom	0.87	33%	-17.9%	+12.8%	54%
Europe *	-	31%	-21.7%	+14.0%	46%
Europe **	0.81	16%	-17.6%	+6.3%	37%

* Independent countries with isolated grids.

** Interconnected grids.

[1] Based on solar and wind generation.

Table D.5.4 – Curtailment strategy for best cost performance. The LCOE reduction and increase are calculated with respect to the baseline. The risk of worsening is obtained as fraction between the number of scenarios in which an increase of the LCOE is observed (from baseline) and the total number of simulations collected for the given curtailment factor.

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Country	Curtailment factor [-]	Share of curtailed generation [1]	Max. GWP100a reduction	Max. GWP100a increase	Risk of worsening
Austria	0.90	72%	-17.4%	+59.4%	97%
Belgium	0.00	0%	0%	0%	0%
Bulgaria	0.89	29%	-10.0%	+85.1%	93%
Czechia	0.69	15%	-5.3%	+25.5%	69%
Denmark	0.89	36%	-12.5%	+20.8%	60%
Estonia	0.89	39%	-15.9%	+3.4%	10%
Finland	0.85	26%	-12.6%	+3.5%	20%
France	0.89	36%	-20.2%	+40.7%	66%
Germany	0.73	19%	-3.9%	+13.0%	76%
Greece	0.89	33%	-11.8%	+56.8%	86%
Hungary	0.84	41%	-9.9%	+60.8%	86%
Ireland	0.76	33%	-16.4%	+1.8%	6%
Italy	0.89	29%	-12.1%	+42.6%	78%
Latvia	0.76	33%	-13.0%	+4.3%	39%
Lithuania	0.89	57%	-14.2%	+38.7%	94%
Netherlands	0.72	38%	-6.8%	+8.8%	67%
Poland	0.77	24%	-9.7%	+1.4%	20%
Portugal	0.89	29%	-14.6%	+62.1%	77%
Romania	0.89	34%	-9.8%	+88.4%	90%
Slovakia	0.89	19%	-13.3%	+106.9%	73%
Slovenia	0.00	0%	0%	0%	0%
Spain	0.89	24%	-12.4%	+45.3%	72%
Sweden	0.91	33%	-9.2%	+0.6%	18%
Switzerland	0.00	0%	0%	0%	0%
United Kingdom	0.89	42%	-15.1%	+26.8%	66%
Europe [*]	-	31%	-11.0%	+28.5%	71%
Europe [**]	0.89	25%	-12.5%	+50.3%	79%

[*] Independent countries with isolated grids.

[**] Interconnected grids.

[1] Based on solar and wind generation.

Table D.5.5 – Curtailment strategy for best environmental performance. The GWP100a reduction and increase are calculated with respect to the baseline. The risk of worsening is obtained as fraction between the number of scenarios in which an increase of the GWP100a is observed (from baseline) and the total number of simulations collected for the given curtailment factor.

D.6 Decarbonization of the energy system

Country	Generation GWP100a [gCO_2eq/kWh]	Generation Share [%]	Storage GWP100a [gCO_2eq/kWh]	Storage Share [%]	Total [gCO_2eq/kWh]
Austria	10.07	36.05%	17.86	63.95%	27.92
Belgium	81.37	53.48%	70.78	46.52%	152.16
Bulgaria	25.33	61.88%	15.60	38.12%	40.94
Czechia	22.62	40.64%	33.04	59.36%	55.66
Denmark	19.00	38.68%	30.12	61.32%	49.12
Estonia	17.64	43.83%	22.60	56.17%	40.24
Finland	17.29	50.14%	17.20	49.86%	34.49
France	18.52	49.81%	18.66	50.19%	37.19
Germany	27.89	50.84%	26.97	49.16%	54.86
Greece	23.84	59.13%	16.48	40.87%	40.32
Hungary	20.75	34.01%	40.26	65.99%	61.02
Ireland	13.76	32.86%	28.12	67.14%	41.88
Italy	21.52	61.66%	13.38	38.34%	34.91
Latvia	18.69	41.08%	26.81	58.92%	45.50
Lithuania	16.61	40.79%	24.11	59.21%	40.72
Netherlands	18.12	34.37%	34.61	65.63%	52.74
Poland	15.92	36.74%	27.41	63.26%	43.33
Portugal	18.98	53.50%	16.50	46.50%	35.48
Romania	25.44	62.71%	15.13	37.29%	40.57
Slovakia	16.50	59.71%	11.13	40.29%	27.63
Slovenia	53.52	63.11%	31.29	36.89%	84.81
Spain	21.81	58.19%	15.67	41.81%	37.48
Sweden	38.13	82.92%	7.85	17.08%	45.98
Switzerland	43.63	53.20%	38.39	46.80%	82.01
United Kingdom	20.60	46.25%	23.95	53.75%	44.55
Europe *	24.21	50.92%	23.34	49.08%	47.54
Europe **	23.33	64.91%	12.61	35.09%	35.94

* Independent countries with isolated grids.
** Interconnected grids.

Table D.6.1 – Global Warming Potential (GWP) [gCO_2eq/kWh] of the generation mix and storage system for the best simulated solutions by country. Results *without curtailment*.

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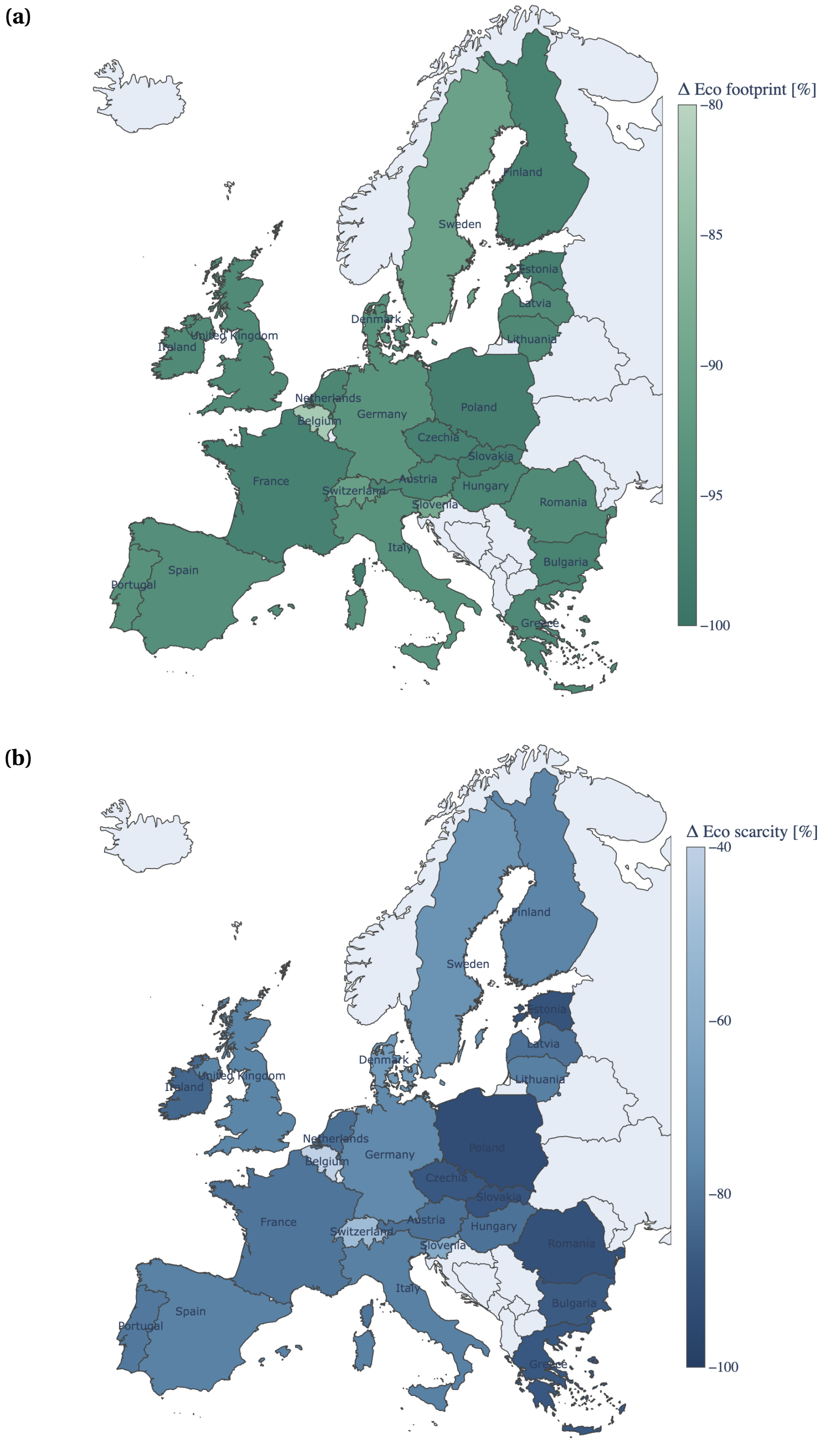

Figure D.6.1 – Percentage change in **(a)** Ecological Footprint and **(b)** Ecological Scarcity (2013) of the best solutions for isolated grids from current values.

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	LCOE [EUR/MWh]				
Country	**L. Whisker**	**Q1**	**Q2**	**Q3**	**H. Whisker**
Austria	89.08	146.49	179.67	216.07	292.03
Belgium	202.54	272.39	299.45	329.37	478.21
Bulgaria	130.88	155.05	163.63	173.91	222.01
Czechia	160.51	192.63	204.08	217.17	285.91
Denmark	177.09	202.15	211.16	221.51	281.73
Estonia	151.02	177.22	185.69	195.09	250.41
Finland	121.35	137.31	143.39	149.92	178.24
France	129.42	152.10	158.61	165.81	205.92
Germany	157.10	183.72	192.17	200.36	243.90
Greece	104.47	134.08	146.88	159.36	203.89
Hungary	199.78	241.88	256.21	272.94	365.62
Ireland	144.12	170.87	180.36	190.77	240.61
Italy	109.90	131.51	139.36	148.98	185.47
Latvia	169.03	209.80	226.24	246.47	332.98
Lithuania	136.59	161.97	169.38	178.86	229.53
Netherlands	178.98	202.19	211.00	221.48	279.51
Poland	142.98	169.44	178.63	188.90	246.07
Portugal	116.37	141.22	149.41	158.63	201.37
Romania	104.28	136.94	150.45	164.58	200.36
Slovakia	93.45	117.62	125.29	133.52	164.46
Slovenia	177.26	240.19	264.09	291.53	459.51
Spain	115.43	143.32	151.78	160.50	197.11
Sweden	50.05	68.79	83.02	97.54	120.31
Switzerland	144.76	202.62	222.06	242.45	324.75
United Kingdom	145.82	171.04	179.15	188.32	236.37
Europe	116.74	139.05	146.45	153.84	184.51

Table D.6.2 – Levelized Cost of Electricity (LCOE) in Euro per MWh by country. Uncertainty analysis results for the solutions *without curtailment*. The lower and higher whiskers correspond to the minimum and maximum cost, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distribution.

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Country	GWP100a [gCO_2eq/kWh] L. Whisker	Q1	Q2	Q3	H. Whisker
Austria	23.87	27.33	28.12	28.99	33.44
Belgium	103.16	141.57	153.70	166.70	244.45
Bulgaria	32.04	39.49	41.24	43.22	56.49
Czechia	45.23	53.41	55.93	58.70	76.02
Denmark	42.36	47.94	49.59	51.38	61.40
Estonia	32.36	38.81	40.51	42.48	51.35
Finland	28.52	33.25	34.80	36.34	45.08
France	30.69	36.14	37.53	39.02	47.22
Germany	45.81	53.09	55.30	57.71	70.58
Greece	32.82	39.02	40.73	42.45	50.48
Hungary	49.41	59.34	61.62	64.04	76.13
Ireland	35.64	40.69	42.21	43.82	53.71
Italy	27.93	33.73	35.23	36.83	45.08
Latvia	38.01	44.11	45.84	47.70	58.40
Lithuania	34.38	39.65	41.12	42.80	51.77
Netherlands	44.56	50.96	53.08	55.40	68.92
Poland	35.80	41.88	43.67	45.71	56.50
Portugal	29.81	34.54	35.77	37.12	43.32
Romania	32.81	39.42	40.95	42.61	50.62
Slovakia	21.68	26.33	27.81	29.37	37.69
Slovenia	57.87	78.83	85.30	92.87	135.67
Spain	31.31	36.38	37.79	39.30	46.15
Sweden	31.11	42.60	45.96	49.90	72.29
Switzerland	56.66	77.20	82.64	88.84	122.39
United Kingdom	36.26	43.19	44.88	46.79	58.17
Europe	29.61	34.72	36.26	37.88	45.78

Table D.6.3 – Grid carbon intensity (GWP100a) in grams of CO_2 equivalent per kWh of consumed electricity. Uncertainty analysis results for the solutions *without curtailment*. The lower and higher whiskers correspond to the minimum and maximum intensity, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distribution.

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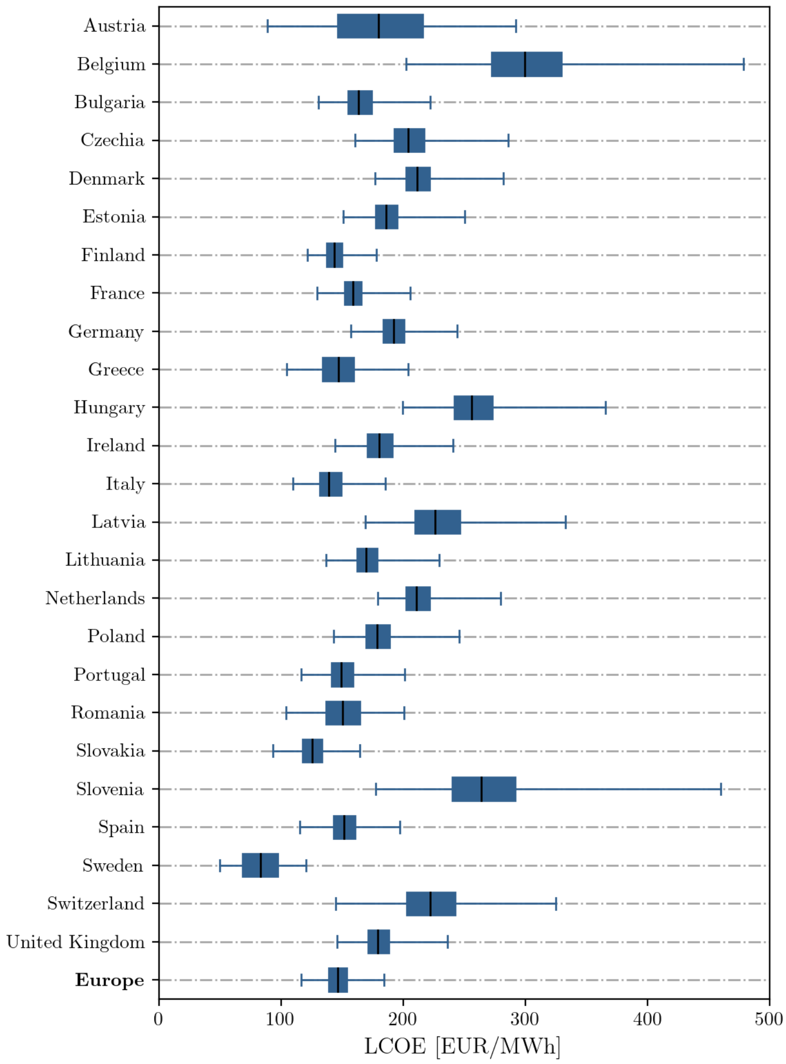

Figure D.6.2 – Results of the best observed simulations *without curtailment*. Levelized Cost of Electricity (LCOE) in Euro per MWh (Table D.6.2).

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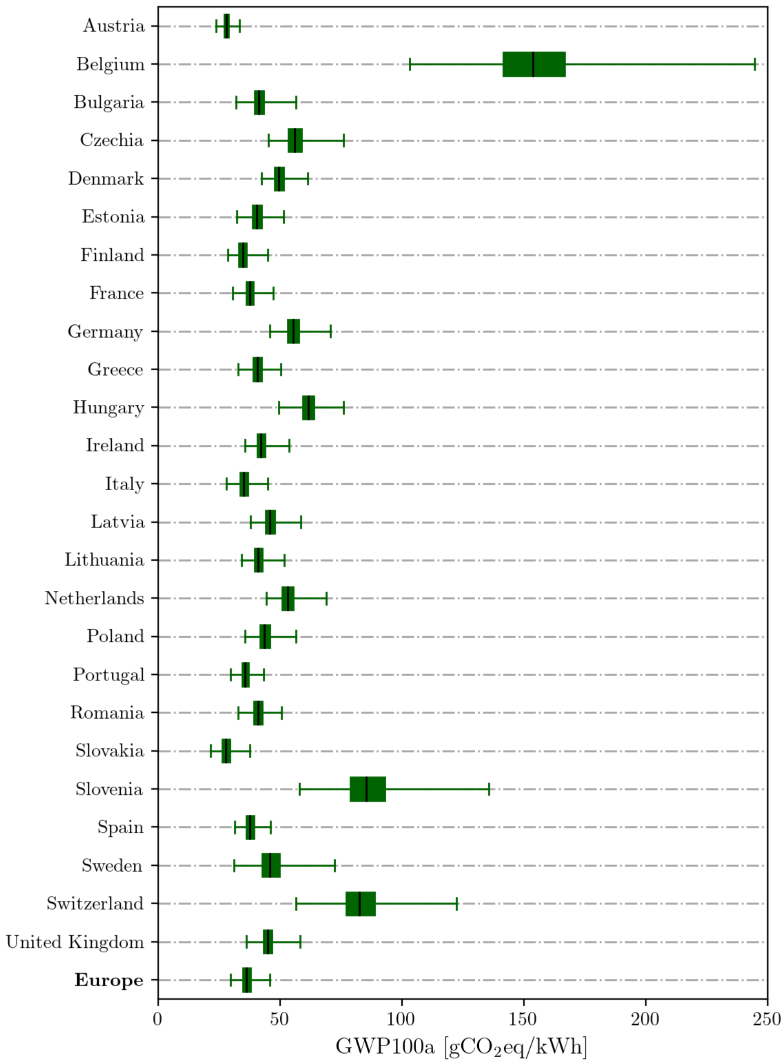

Figure D.6.3 – Results of the best observed simulations *without curtailment*. Grid carbon intensity (GWP100a) in grams of CO_2 equivalent per kWh of consumed electricity (Table D.6.3).

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Country	**Population**	**GDP** [MEUR]	**GHG** em. per capita [tCO_2eq/capita]	**GDP** intensity [tCO_2eq/MEUR]
Austria	8822	385712	5.67	129.58
Belgium	11399	459820	6.11	151.50
Bulgaria	7050	56087	4.48	563.18
Czechia	10610	207570	7.79	398.41
Denmark	5781	301342	3.90	74.77
Estonia	1319	26036	5.81	294.25
Finland	5513	234370	5.27	124.07
France	66919	2353090	3.41	97.01
Germany	82792	3344370	6.08	150.63
Greece	10741	184714	5.20	302.19
Hungary	9778	133782	4.21	307.37
Ireland	4830	324038	6.68	99.61
Italy	60484	1766168	4.78	163.77
Latvia	1934	29056	3.74	249.11
Lithuania	2809	45264	3.63	225.57
Netherlands	17181	774039	7.03	156.06
Poland	37977	496362	7.33	560.62
Portugal	10291	204305	3.43	172.89
Romania	19531	204640	2.67	255.14
Slovakia	5443	89721	4.40	266.87
Slovenia	2067	45755	5.55	250.67
Spain	46658	1202193	3.63	140.93
Sweden	10120	471209	2.08	44.64
Switzerland	8484	679800	4.24	52.94
United Kingdom	66274	2423748	4.45	121.57
Europe	514807	16443192	4.86	152.30

Table D.6.4 – Current environmental indicators by country. The population is given in thousands of inhabitants and the Gross Domestic Product (GDP) at market prices is given in Million Euros [MEUR] with 2015 as reference year. The Green House Gas (GHG) emissions per capita and the GDP intensity are given in tonnes of CO_2 equivalent emitted per inhabitant [tCO_2eq/capita] and per million euros [tCO_2eq/MEUR], respectively.

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Country	GHG emissions per capita [tCO_2eq/capita]					
	L. Whisker	Q1	Q2	Q3	H. Whisker	Change [%]
Austria	0.65	0.75	0.77	0.79	0.91	-86%
Belgium	2.76	3.79	4.11	4.46	6.54	-33%
Bulgaria	0.45	0.55	0.57	0.60	0.79	-87%
Czechia	1.02	1.21	1.26	1.33	1.72	-84%
Denmark	1.06	1.20	1.24	1.29	1.54	-68%
Estonia	0.78	0.93	0.97	1.02	1.23	-83%
Finland	1.02	1.19	1.25	1.30	1.61	-76%
France	0.66	0.78	0.81	0.84	1.02	-76%
Germany	1.05	1.22	1.27	1.33	1.62	-79%
Greece	0.47	0.56	0.59	0.61	0.73	-89%
Hungary	0.89	1.06	1.10	1.15	1.36	-74%
Ireland	0.83	0.95	0.98	1.02	1.25	-85%
Italy	0.54	0.66	0.68	0.72	0.88	-86%
Latvia	0.76	0.88	0.92	0.96	1.17	-75%
Lithuania	0.69	0.80	0.83	0.86	1.04	-77%
Netherlands	1.01	1.15	1.20	1.25	1.56	-83%
Poland	0.66	0.77	0.81	0.84	1.04	-89%
Portugal	0.44	0.51	0.53	0.55	0.64	-85%
Romania	0.39	0.46	0.48	0.50	0.60	-82%
Slovakia	0.36	0.43	0.46	0.48	0.62	-90%
Slovenia	1.36	1.86	2.01	2.19	3.20	-64%
Spain	0.51	0.59	0.62	0.64	0.75	-83%
Sweden	0.86	1.18	1.27	1.38	2.01	-39%
Switzerland	1.35	1.83	1.96	2.11	2.91	-54%
United Kingdom	0.69	0.82	0.85	0.89	1.11	-81%
Europe	0.60	0.70	0.73	0.77	0.93	-85%

Table D.6.5 – Green House Gas (GHG) emissions per capita [tCO_2eq/capita]. Uncertainty analysis results. The lower and higher whiskers correspond to the minimum and maximum observed emissions per inhabitant, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distribution. The relative change [%] represents the improvement from the indicator associated with the current energy system (Table D.6.4).

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	GDP intensity [tCO_2eq/MEUR]					
Country	**L. Whisker**	**Q1**	**Q2**	**Q3**	**H. Whisker**	**Change [%]**
Austria	14.90	17.06	17.55	18.09	20.88	-86%
Belgium	68.45	93.94	101.99	110.62	162.21	-33%
Bulgaria	56.06	69.09	72.15	75.62	98.83	-87%
Czechia	52.20	61.64	64.55	67.74	87.73	-84%
Denmark	20.36	23.04	23.84	24.69	29.51	-68%
Estonia	39.30	47.13	49.19	51.58	62.36	-83%
Finland	24.02	28.00	29.30	30.60	37.96	-76%
France	18.77	22.11	22.96	23.87	28.88	-76%
Germany	26.10	30.25	31.51	32.88	40.21	-79%
Greece	27.50	32.69	34.13	35.57	42.30	-89%
Hungary	64.72	77.73	80.71	83.88	99.72	-74%
Ireland	12.38	14.13	14.66	15.22	18.66	-85%
Italy	18.58	22.45	23.44	24.51	30.00	-86%
Latvia	50.73	58.87	61.18	63.66	77.95	-75%
Lithuania	43.02	49.62	51.44	53.55	64.78	-77%
Netherlands	22.41	25.62	26.69	27.86	34.65	-83%
Poland	50.50	59.07	61.60	64.47	79.70	-89%
Portugal	22.28	25.82	26.74	27.74	32.38	-85%
Romania	36.82	44.24	45.95	47.81	56.80	-82%
Slovakia	21.70	26.35	27.83	29.39	37.72	-90%
Slovenia	61.57	83.87	90.75	98.81	144.34	-64%
Spain	19.86	23.07	23.97	24.93	29.27	-83%
Sweden	18.53	25.38	27.38	29.73	43.07	-39%
Switzerland	16.79	22.88	24.50	26.33	36.28	-54%
United Kingdom	18.84	22.44	23.32	24.31	30.22	-81%
Europe	18.78	22.02	23.00	24.03	29.04	-85%

Table D.6.6 – Gross Domestic Product (GDP) intensity [tCO_2eq/MEUR]. Uncertainty analysis results. The lower and higher whiskers correspond to the minimum and maximum observed intensities, respectively. Q1, Q2 and Q3 are the first, second and third quartiles of the distribution. The relative change [%] represents the improvement from the indicator associated with the current energy system (Table D.6.4).

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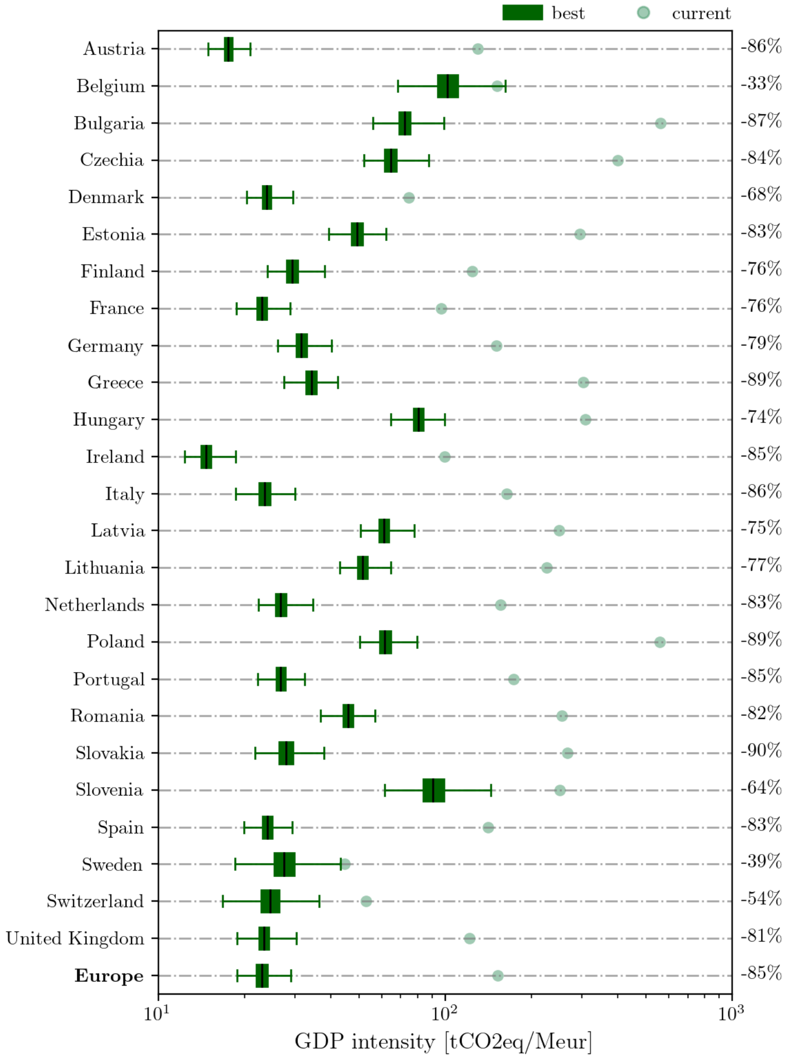

Figure D.6.4 – Gross Domestic Product (GDP) intensity [tCO_2eq/Meur] of the best solutions by country and current energy systems. (Table D.6.6). The percentage reduction of the 100% renewable grid (median) from the current energy system (light green) is displayed on the right side of the chart.

	EAC / GDP [-]				
Country	**L. Whisker**	**Q1**	**Q2**	**Q3**	**H. Whisker**
Austria	0.023	0.038	0.047	0.056	0.076
Belgium	0.059	0.079	0.087	0.096	0.140
Bulgaria	0.119	0.141	0.149	0.159	0.202
Czechia	0.083	0.100	0.106	0.113	0.148
Denmark	0.034	0.039	0.041	0.043	0.055
Estonia	0.080	0.094	0.099	0.104	0.133
Finland	0.060	0.068	0.071	0.074	0.088
France	0.038	0.045	0.047	0.049	0.061
Germany	0.041	0.048	0.050	0.052	0.064
Greece	0.041	0.053	0.058	0.063	0.081
Hungary	0.112	0.135	0.143	0.153	0.204
Ireland	0.021	0.025	0.026	0.027	0.035
Italy	0.030	0.036	0.038	0.041	0.051
Latvia	0.082	0.102	0.110	0.120	0.162
Lithuania	0.066	0.078	0.082	0.087	0.111
Netherlands	0.041	0.046	0.048	0.051	0.064
Poland	0.084	0.100	0.105	0.111	0.145
Portugal	0.039	0.048	0.050	0.053	0.068
Romania	0.048	0.063	0.069	0.076	0.092
Slovakia	0.047	0.059	0.063	0.067	0.083
Slovenia	0.078	0.105	0.116	0.128	0.202
Spain	0.034	0.043	0.045	0.048	0.059
Sweden	0.019	0.027	0.032	0.038	0.047
Switzerland	0.020	0.028	0.030	0.033	0.044
United Kingdom	0.031	0.037	0.038	0.040	0.051
Europe *	0.039	0.047	0.050	0.053	0.067
Europe **	0.033	0.040	0.042	0.044	0.053

* Independent countries with isolated grids.
** Interconnected grids.

Table D.6.7 – Equivalent Annual Cost (EAC) relative to the Gross Domestic Product (GDP) by country.

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2014 - 2016 **MSc Mechanical Engineering**, *Swiss Federal Institute of Technology Lausanne (EPFL)*, Switzerland.

- Major: Aero-Hydrodynamics – Minor: Energy
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2011 - 2014 **BSc Aerospace Engineering**, *Polytechnic University of Milan*, Italy.

Experience

2017 - 2020 **Teaching Assistant**, *Swiss Federal Institute of Technology Lausanne (EPFL)*, Switzerland.

- Mathematical modelling, optimisation and economics in energy systems

2016 **Intern**, *INEOS*, Hull, United Kingdom.

- Identification of energy savings opportunities in petrochemical sites
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IT Skills

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Network TCP/IP, UDP, HTTP

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