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Scenarios on future electricity storage requirements in the austrian electricity system with high shares of variable renewables

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ABSTRACT

This paper presents three scenarios (*policy*, *renewables and electrification* and *efficiency*) for transitioning to a 100 % renewable electricity sector in Austria, based predominantly on wind and photovoltaics, alongside sector-specific electrification. Considering renewable expansion targets and three distinctive weather years from an overall system perspective, the core objective is to minimize variable costs of electricity storage and dispatchable power plants. The model developed determines their optimal dispatch for meeting the underlying electricity demand each hour. Within the scenarios for renewable expansion, a special focus lies on integrating short-duration (batteries), medium-duration (pumped storage hydro) and long-duration (hydrogen) energy storage. Our analysis reveals the significant impact of weather patterns on renewable electricity generation, particularly the differences between winter and summer generation quantities. This necessitates seasonal balancing and the mitigation of extremes like low wind power events, which require corresponding backup capacities. This contrast is particularly evident when comparing the years 2030–2050, wherein in the latter, certain dispatchable generators are only utilized in one of the three underlying weather years during extreme weather conditions. In our paper, we demonstrate how, especially for hydrogen production and storage, weather conditions influence production levels and the re-electrification demand. The results indicate the feasibility of achieving a fully decarbonized energy system in Austria through suitable policy measures and expanded renewable generation, with long-duration storage playing a crucial role in seasonal balance and compensating for the absence of fossil fuel generation. Strategic planning is essential to aligning the expansion of renewable energy generation with the necessary flexibility.

1. Introduction

The prevailing energy system is undergoing a substantial transformation as it endeavors to shift from a predominantly fossil-based infrastructure to a renewable one. This is coupled with electrification initiatives in specific sectors, notably the transportation sector. In Austria, the enactment of the "Renewable Energy Expansion Act (EAG)" signifies a concrete commitment to achieving 100 % renewable electricity by 2030 on a national balance[1] [1]. This target, calculated on a net basis, entails exporting renewable electricity in equivalent measures to offset electricity generated from fossil fuels throughout the year within the public grid, implying that the future generation capacities will predominantly be shaped by wind and solar sources. Within this context, the inherent variability of renewable sources poses specific challenges to the existing electricity infrastructure, as shown in Fig. 1. These ongoing changes underline the need for a nuanced understanding of current systems, which requires thoroughly examining the challenges and exploring possible solutions.

As part of the transition to a sustainable energy future, there is much debate about what shape the electricity system will or should take. Integral to the discussion is the question of the required storage capacity, which has led to considerable discussion in the energy community, particularly regarding the transfer of surplus electricity generated in the summer months for use in the winter period. Our paper contributes to this discussion by presenting three scenarios (*policy*, *renewables and electrification* and *efficiency*), which include different expansion paths for renewable energies, electricity demand and storage capacities, weather years and their resulting utilization dynamics within the specified scenarios. The aim is to model the Austrian electricity system to

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[1] Excluding privately generated electricity from fossil fuel sources in the goods production sector and balancing energy and control energy for stabilizing grid operations [90].

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Abbreviations:

AIT	Austrian Institute of Technology
APG	Austrian Power Grid
CCGT	Combined cycle gas turbine
CO_2	Carbon dioxide
DSM	Demand-side management
EAG	Renewable Energy Expansion Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EV	Electric vehicle
HP	Heat pump
PECD	Pan European Climate Database
PSH	Pumped storage hydro
PV	Photovoltaics
SH	Storage hydro

demonstrate the impacts of various influencing factors. With a focus on complete decarbonization and extensive integration of hydrogen storage for seasonal purposes, our research seeks to provide insights into the functionality and interdependence among batteries, pumped storage hydro (PSH), storage hydro (SH) and underground hydrogen within renewable-based electricity systems. Moreover, it emphasizes significant differences in storage utilization based on weather conditions from an overall system perspective.

The following research questions are addressed.

- What form will future electricity storage scenarios take, considering different variable renewable electricity integration scenarios, demand patterns and underlying weather conditions?
- How does the variability of weather patterns impact renewable energy generation and the resulting utilization of storage and dispatchable generation in Austria, specifically focusing on low wind power events and dark doldrums?
- What are the differences in the full-load hours of storage technologies between 2030 and 2050 in Austria's fully renewable electricity system?
- What constitutes the cost-optimized dispatch of flexible generation and storage for each defined economic scenario and weather year?

We develop an hourly cost-minimizing electricity market and energy storage dispatch model, with the aim of minimizing the overall variable generation costs associated with dispatchable technologies under externally imposed renewable expansion targets. The model encompasses three scenarios for expansion of renewables with an ultimate phase-out of fossil generation by incorporating short- (batteries), medium- (PSH) and long-duration (hydrogen) energy storage capabilities. It illustrates an optimal dispatch of incorporated storage technologies for meeting the underlying electricity demand each hour.

The paper is organized as follows: Section 2 provides an overview of literature. The model is then explained in Section 3, while Section 4 presents the results. The conclusions and outlook are presented in Section 5.

2. Literature

The integration of increasingly larger amounts of variable renewable generation into existing power systems due to ambitious decarbonization goals is making system flexibility more crucial. In recent years, numerous power system models have been developed, such as those by Lund et al. [2] and Möst et al. [3], focusing on the European Union to better understand the associated challenges of integrating variable renewable generators, but no single modeling tool comprehensively addresses all aspects of renewable energy integration [4]. Comprehensive reviews of power system models with large shares of renewables can be found in Subramanian et al. [5], Ringkjøb et al. [6] and Connolly et al. [4]. The feasibility of implementing power systems with up to 100 % renewable generation is still debated in the literature [7], but it has been confirmed in several studies that this transition is economically competitive and technically feasible [8]. An optimal composition of 55 % wind and 45 % photovoltaics (PV) across Europe was identified by Heide et al. [9] as a seasonal optimal mix in a 100 % renewable power system scenario where only wind and PV were applied in the electricity sector. Another analysis conducted by Zerrahn et al. [10] concludes that the energy transition is unlikely to fail due to insufficient storage capacities, addressing Sinn's [11] suggestion that further expansion of wind and solar energy in Germany will reach a limit due to the lack of electricity storage. Sinn's analysis considers only extreme solutions, i.e., either no electricity storage or no curtailment of renewable energies, but a combination of storage and curtailment is economically more plausible [12]. Austria set itself the goal of achieving a power system with 100 % renewable energy by 2030 (on a national balance), with the aim of being climate neutral by 2040. Although certain scenarios and model calculations until 2030 are already available, such as those by Haas et al. [13], the current conditions are changing rapidly (e.g., stricter emission reduction targets) for the European power system, necessitating calculations with updated scenarios and models. This also affects electricity import and export capacities to and from neighboring countries, which could decrease in the future, especially in the winter months, as

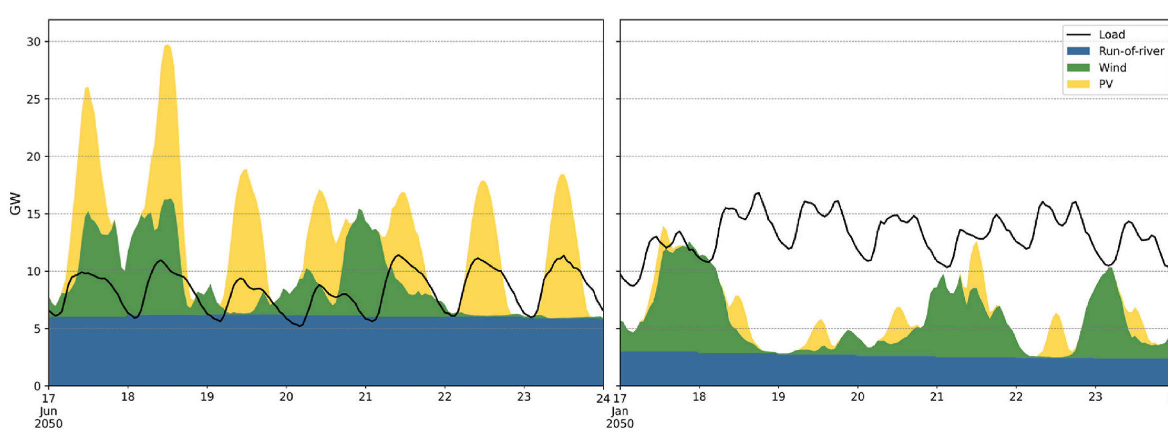

Fig. 1. Extract from a summer week (17.6.-24.6.2050) and a winter week (17.1.-24.1.2050) to illustrate renewable generation and load (policy scenario (A), weather year 2016).

coal-fired capacities are scaled back. These impacts are considered in two of the scenarios developed in this paper, with a tighter limitation on import/export exchanges (modeled as artificial storage in our case).

The question of the required storage capacities in a fully renewable electricity system has also been intensely debated [14–18]. Examining the required electricity storage capacities at the European level, Cebulla et al. [19] calculate a required capacity of 206 GW and 30 TWh with 89 % renewable generation (of the annual gross electricity generation). Steffen and Weber [20] applied peak-load pricing theory to determine the optimal storage capacity, finding that significant storage expansion becomes essential only at around 80 %. Additionally, Victoria et al. [21] conclude that substantial storage capacities are only deemed necessary when achieving a CO_2 emission reduction of more than 80 % from the 1990 level. Nevertheless, without fossil power plants capable of compensating for the seasonal fluctuations of renewables, seasonal storage becomes necessary, as Safaei and Keith [18] found in their study focusing on the United States electricity system. There is a broad consensus in the literature that electricity storage requirements will remain moderate until quite high shares of renewables are integrated into the power sector [22]. This approach is also employed in this paper, aiming to achieve an optimal balance between renewable energy generation and storage, ensuring the balance of supply and demand in each hour, even during weather years with unfavorable conditions. Nonetheless, maximizing the utilization of storage technologies is paramount to ensuring their cost-effective operation.

In addition to the aforementioned scenario development regarding the expansion of renewable generation, there are also ongoing demand-side changes [23]. Electrification of end uses like heat pumps (HPs) and electric vehicles (EVs) is efficient for achieving climate neutrality, while non-electrified applications such as hydrogen also influence electricity consumption and consumer load profiles [24]. Rüdisüli et al. [25] highlight impacts in Switzerland, where integrating HPs and EVs without additional storage may necessitate winter and nighttime electricity imports despite surplus PV in summer. However, a study at the EU level by Möst et al. [3] concluded that demand-side management diminishes potential storage profits, indicating competition among flexibility options. Sousa et al. [26] compare scenarios in Portugal integrating EVs, storage, and hydrogen, using cost-minimization models to optimize dispatchable generation and storage. These aspects are examined in the present paper for Austria, which envisions a transition of the Austrian electricity system to 100 % renewable energy. For each developed scenario, different demand profiles are modeled to capture potential developments and to integrate different market trends of HPs and EVs. The specificities in the demand of both are also integrated using charging profiles for EVs and temperature profiles for HPs.

However, the authors acknowledge that a comprehensive representation of all sectors is advantageous in energy system modeling and view the energy system holistically and implement a smart energy system [27]. This is particularly important for the utilization of surplus energy, which can often be deployed more cost-effectively in other sectors [22]. Due to the complexity arising from this, no bidirectional interactions between different sectors were modeled during the initial development step. The heating and transport sectors, however, have been included by integrating HP and EV profiles in the overall load with different scenarios. Regarding hydrogen, the present model only restricts hydrogen storage by power capacities (electrolysis and re-electrification). The energy capacity, i.e., the underground reservoir, can store as much hydrogen as necessary or even higher quantities than ultimately required for re-electrification to achieve cost-effective scenarios. This surplus can then be utilized in sectors other than the electricity system, such as in the industry. The lack of restrictions on hydrogen storage is justified by the availability of large capacities in depleted gas fields or existing fossil gas storage facilities for underground hydrogen storage, as noted by Talukdar et al. [28]. Therefore, surplus amounts can be incorporated as hydrogen for other sectors in the model.

One strand of the literature is dedicated to electricity sector modeling with a focus on electricity storage, encompassing different geographical coverage, time horizons and methodological approaches [29]. According to López Prol and Schill [29], these models can be further classified into price-taking arbitrage models utilizing historical electricity market prices, models based on time series of variable renewables and state-of-the-art electricity sector models, often incorporating capacity expansion. In the comprehensive review by Sioshansi et al. [30], existing modeling types are categorized into price-taking, very short-run, production cost, strategic behavior, capacity expansion and portfolio planning and resource adequacy. An essential overview of electricity storage models is provided by Zerrahn and Schill [31]. Some storage studies reviewed here adopt a technology-specific approach. For instance, Babrowski et al. [32] focus on optimizing battery storage in the German electricity system until 2040. Thema et al. [33] undertake calculations for the necessary power-to-gas capacities, suggesting that expansion must commence by 2035 to achieve an installed capacity of 89–134 GW in Germany by 2050. According to their analysis, this could lead to annual cost savings of 2–6 billion euros (by 2040) and up to 18 billion euros (by 2050) compared to a scenario without power-to-gas. These estimations are based on the assumption that in the absence of power-to-gas, expenses for remunerated curtailment would escalate and supply shortfalls would necessitate the use of costly gas power (due to a CO_2 price of €100/t CO_2). Another study with a power-to-gas focus was conducted by Lyseng et al. [34], where wind and PV are modeled for an 80 % variable renewable electricity scenario. The findings demonstrate a 23 % reduction in the required wind and PV capacities and up to an 87 % decrease in curtailment when power-to-gas capacities are integrated. In addition to the aforementioned papers with a technological focus, other optimization models concentrate on individual countries such as Finland [35], Spain [36], as well as the United States by Arbabzadeh et al. [37] and Dowling et al. [38].

What is often scarcely or not included in the aforementioned state-of-the-art electricity sector models, except in Dowling et al. [38], is the influence of climatic conditions on storage requirements and seasonal balancing due to the high temporal resolution and long computational times of optimization when multiple years are included [39]. Models focusing on time series of variable renewables address these temporal patterns[29]. Numerous studies concentrate on wind energy analysis, exemplified by that of Grams et al. [40], who elucidate the extended fluctuations in European wind energy production with different weather profiles. Periods of low wind power events in particular are analyzed by Ohlendorf and Schill [41], revealing that such events occur less frequently in winter than in summer. In all years analyzed, there is a period of five consecutive days with an average capacity factor of less than 10 % of the wind capacities. Extended to eight days, such events occur every ten years [41]. The authors, therefore, recommend integrating multiple weather years into modeling. In the present model, a weather year with the mentioned eight days below 10 % capacity, alongside two others with an average of five days, was integrated to adhere to these recommendations. Kruyt et al. [42] find fewer low wind events at higher altitudes, suggesting potential for wind energy expansion in higher altitudes. A spatial expansion of the area investigated (grid integration) also reduces the occurrence of low wind power events, as demonstrated by Handschy et al. [43], who find that the annual number of hours with low wind events decreases exponentially with the number of aggregated sites. A joint analysis of wind and PV is presented by Collins et al. [44], concluding that in decarbonized energy systems, the influence of long-term weather patterns is greater, estimating a five-fold increase in operational variability by 2030.

All the studies mentioned, however, focus on analyzing various weather conditions of different technologies but are not electricity sector models. However, this becomes increasingly crucial as the share of renewable electricity generation rises, particularly during periods of energy deficit [45]. Our paper aims to integrate both aspects. We utilize an optimization model incorporating the influence of different weather years, as previously conducted for Germany by Ruhnau and Qvist [45].

In this context, three weather years are included in the optimization to depict diverse conditions. Although fewer in comparison to the aforementioned paper, our research does show scenarios with different electricity generation and demand trajectories. Moreover, our paper provides a more detailed analysis of storage interaction. Additionally, we include the impact of three weather years, encompassing variations in PV, wind and water production, while also considering temperature disparities for HPs and air conditioning electricity demands. These three weather years are limited in scope as we rely on data from the Austrian transmission system operator Austrian Power Grid (APG) for wind and PV analysis, available from 2015 onwards, and data from ENTSOE for hydraulic analysis (natural water inflows into reservoirs and run- and river plants), available up to 2017. Nonetheless, the optimization is predicated on a weather year characterized by a confirmed period of dark doldrums. Dark doldrums are characterized by low renewable generation due to low water levels in reservoirs, minimal wind, cloudy weather with low temperatures and consequently, high demand. We include the year 2017 in our model, which witnessed the most well-known dark doldrums in Austria and Germany [46].

To summarize, the main aim of our paper is to achieve a deeper understanding of the dynamics of batteries, PSH, SH and underground hydrogen storage in the context of electricity systems largely or fully based on renewable sources, contingent upon the different trajectories of renewable electricity system development. Additionally, essential differences regarding storage utilization depending on weather conditions are highlighted. We see this as a vital contribution as the investigated studies focusing on the joint integration of different storage technologies to achieve a 100 % renewable electricity system often lack consideration of climate variabilities. Our paper also emphasizes long-term development, wherein the electricity system is fully transitioned to renewable technologies and is more electrified on the demand side. The latest policy developments from Austria, such as the 100 % renewable energy target and the objective of climate neutrality, are also incorporated into the analysis. While Austria serves as the primary case study, the model's adaptability allows for calibration to other countries with a high share of renewable electricity generation.

3. Methods and data

The analytical framework employed is a cost-minimizing electricity market and energy storage dispatch model, extending the work of Ramsebner and Haas [47]. This model, designed to optimize the hourly dispatch of generation and storage units, aims to minimize short-term variable costs, effectively portraying a stylized merit-order structure, implying perfect competition. To explore future scenarios up to the year 2050, we define three distinct scenarios (*policy (A)*, *renewables and electrification* (B) and *efficiency (C)*), necessitating the formulation of a range of simplifying assumptions. Among these is our modeling of Austria as one node ("copper plate"), whereby regional and network-specific constraints have been disregarded. The spatiotemporal resolution is on an hourly basis for a representative year for one node, allowing the model to account for short-term dynamics and seasonal features within the system. Dispatchable generation is aggregated across all power plants of a particular technology within the market, while renewable generation is partially modeled based on different historical weather years but incorporates adaptations in generation profiles for component improvements such as wind turbines. HPs are modeled based on temperature data, electric mobility is based on driving patterns and the remaining load components are modeled based on historical load profiles, taking into account the scenario assumptions regarding the development of electricity consumption.

The modeling framework encompasses a set of exogenous model parameters. These are, on the generation side, availability/capacity factors for renewable generators on an hourly basis and hydraulic data for natural inflows of PSH, SH and run-of-river hydroelectricity generation, spanning three weather years and simulating the behavior of hydropower plants under diverse weather conditions. Time series on an hourly resolution are used for the renewable generation and the load. Hourly historical power factors for wind and PV were calculated from renewable generation profiles based on actual measurements provided by the APG [48], adjusted for the efficiency increases (e.g., increase of hub height and rotor diameter) according to industry estimates [49]. Comprehensive datasets are available, beginning with the year 2015. Hourly data concerning run-of-river hydroelectricity generation and natural inflows of SH and PSH are derived from the Pan European Climate Database (PECD), a dataset employed by the European Network of Transmission System Operators for Electricity (ENTSO-E) in their Ten-Year Network Development Plan for 2022 [50]. For our analysis, we use the 2015–2017 dataset to incorporate different meteorological conditions to account for changes in renewable electricity production among weather patterns. These three weather years are limited in scope because, for the analysis of wind and PV, we rely on data from the APG to integrate efficiency improvements of wind and PV, which are available from 2015 onward, and for hydraulic analysis, we use data from PECD (natural water inflows into reservoirs and run- and river plants), which are available until 2017. However, this excerpt includes typical weather years, including an extreme year, as well as a year with particularly high renewable generation of each specific technology.

Demand-side inputs encompass load time series on an hourly basis, including individual profiles for EVs and HPs, along with temperature data influencing HP profiles. The load time series used in our paper constitutes a compilation derived from three data sources. HP profiles were obtained by utilizing the load profile generator developed by the Austrian Institute of Technology (AIT) [51]. This tool facilitates the selection of specific scenario outlines aligned with our designated scenarios outlined in the subsequent section, enabling the generation of electricity load profiles for the HPs based on inputted temperature data profiles. The temperature profiles are taken from the Open Power System Data Platform [52]. Similarly, EV profiles are generated by employing the AIT load profile generator, accounting for the scenarios, driving and charging behaviors and market developments in EVs, incorporating a degree of load management [53]. The residual electricity load was sourced from historical load profiles provided by the APG, available from 2015 onwards and adjusted according to scenario outline demand trajectories. These three distinct time series were merged and integrated into the model as electricity consumption across all network levels, including losses within the grid, stabilization and control of grid operations, electricity utilized by power plants for internal operations, but excluding own consumption of companies covered by own plants when not included into the public grid and households demand covered by PV and batteries. This is also in line with the Environment Agency Austria and Suna et al. [46].

Parameter inputs are variable production costs (including fuel and carbon dioxide (CO_2) costs), capacities and technical details of storage technologies and scenario data. The optimization process involves the simulation of renewable generation based on weather years, resulting in the residual load and the subsequent minimization of variable costs under imposed restrictions, using the programming language Python and solved with the Gurobi Optimizer. The model's outputs include the residual load for each scenario, hourly dispatch of power plants, and storage and curtailment. The underlying logic is that any surplus in the electricity system requires curtailment. However, such curtailment is not invariably due to grid constraints but rather to insufficient demand or storage capacities within the system at a given hour (unused renewable surplus). In the following, only the term curtailment is used. The method is summarized in Fig. 2.

We calibrate the model parameters based on the characteristics of the Austrian electricity system due to the availability of detailed input data. Specifically, our model is tailored to represent the Austrian electricity landscape, characterized by an already high share of renewable generation and with the aim of achieving 100 % RE in the power sector (national balance) by 2030. Notably, the insights derived from our paper

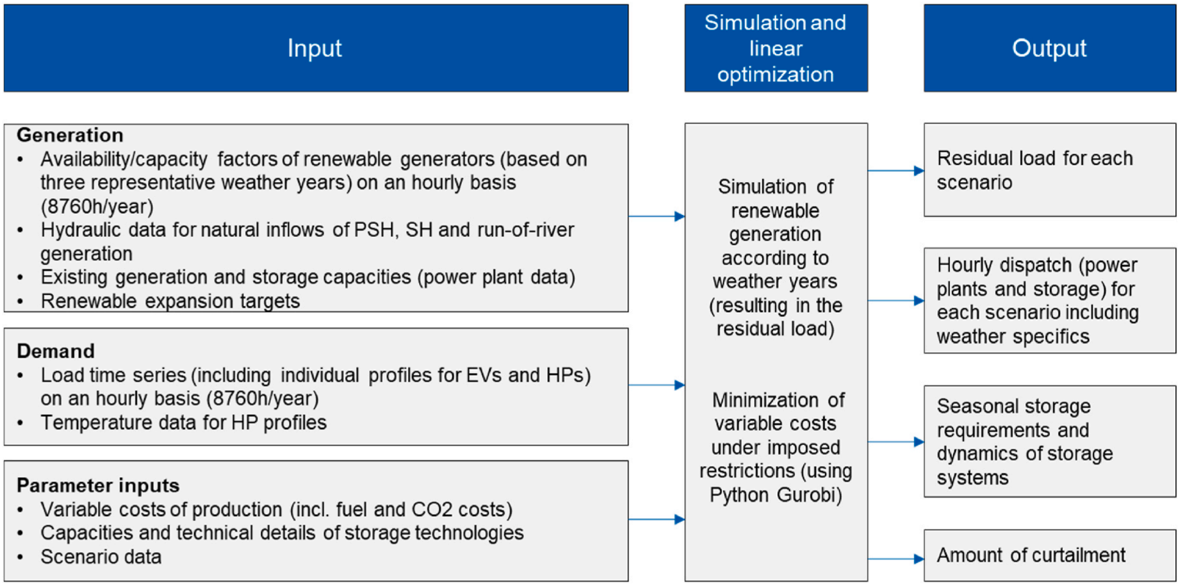

Fig. 2. Overall structure of the model.

hold relevance not only for Austria but also for other countries undergoing the same transition towards renewable sources.

3.1. Model setup

The objective function of the model is designed to achieve cost minimization for dispatchable power generation and storage in each defined scenario:

$$\min\left(\sum_{t\in T}\sum_{i\in I} c_i \; P_{i,t} + \sum_{t\in T}\sum_{sto\in STO} c_{sto} \; P_{sto,t}\right) (€ / \mathrm{a}) \tag{1}$$

The model operates on an hourly basis, aiming to minimize the overall variable generation costs within the entire single-price market zone and is formulated as the sum of two terms: the first term represents the variable costs associated with dispatchable power plants (i) (fossil, waste, biomass and biomethane) over the number of time periods (T), considering variable costs (c, *in €/MWh*) and the dispatchable power plant capacity (P_i , *in MW*). The second term accounts for the variable costs of storage technologies (PSH, SH, battery and hydrogen storage) (sto) over the same time horizon. The variable costs of storage (c_{sto} ,*in €/ MWh*) only include operation and maintenance costs since the aim is to optimize based on a system view and overall welfare. Therefore, profit maximization of individual storage operators is not taken into account in this analysis.

Variable costs are computed from fuel costs (c_{fuel} , *in €/ MWh*), CO_2 costs (c_{CO2}, *in €/MWh*), operation and maintenance costs ($c_{O\&M}$, *in €/ MWh*):

$$c = c_{fuel} + c_{CO2} + c_{O\&M} \quad (€ / \mathrm{MWh}) \tag{2}$$

The costs utilized, along with the literature references, are provided in Appendix C. Regarding curtailment, we have made an assumption that the variable cost slightly exceeds that of the most expensive storage option. This approach ensures that not every surplus hour needs to be curtailed and allows for the construction of additional hydrogen capacity. Biomass, which includes the combustion of solid biomass and biogas, is assumed to be operated flexibly in the future. Notably, renewables are excluded from the objective function as they are presumed to generate power with zero variable costs, serving as must-feed capacities in the model. The merit-order curve is utilized to order power plants based on ascending variable costs, optimizing system-wide costs.

Subject to the condition that demand must be met every hour, the model's constraints ensure a continuous balance between demand and supply:

subject to

$$P_{RE,t} + \sum_{i\in I} P_{i,t} + \sum_{sto\in STO}\left(P_{sto,out,t} - P_{sto,in,t}\right) + P_{imp,t} - P_{exp,t} - P_{curt,t} - P_{load,t} = 0 \;\forall t \in T, i \in I, sto \in STO \;(\mathrm{MW}) \tag{3}$$

This includes the requirement that in every hour, the power of renewable electricity (P_{RE}, *in MW*) plus the power output of all storage technologies discharging ($P_{sto,out}$, *in MW*), the power of all dispatchable power plants and import (P_{imp}, *in MW*) minus the power of storage technologies charging ($P_{sto,in}$, *in MW*), the exports (P_{exp}, *in MW*), the curtailment (P_{curt}, *in MW*) and the overall load of the system (P_{load}, *in MW*) must equal zero. The power of renewable electricity comprises run-of-river hydroelectricity, wind and photovoltaic sources. Hydroelectric power plants are categorized into run-of-river hydroelectricity, SH and PSH capacities, with run-of-river hydroelectricity included in must-feed renewable capacities and SH and PSH modeled as dispatchable storage constrained by natural inflows and reservoir levels. The storage capacities are subject to certain constraints that define the storage state of energy/charge (E_{sto}, *in MWh*) (filling level of the energy capacity of the respective storage capacity), the efficiency of the charging and the discharging (η) and natural water inflows (E_{inflow}, *in MWh*) of each timestep, considering the energy stored in the previous period and the charging and discharging power of in this period.

$$\sum_{sto\in STO}\left(E_{sto,t} - E_{sto,t-1} - \mathrm{P}_{\mathrm{sto,in,t}}\,\eta_{\mathrm{sto,in}} 1 + \frac{\mathrm{P}_{\mathrm{sto,out,t}}}{\eta_{\mathrm{sto,out}}} 1 - E_{inflow,t}\right) = 0 \;\forall t \in T, sto \in STO \;(\mathrm{MWh}) \tag{4}$$

As storage technologies, SH, PSH, battery systems and hydrogen storage, with respective efficiencies and energy and power capacities, were considered. For SH units, there is no pumping possibility, hence the parameter storage charging power ($P_{sto,in}$, *in MW*) does not apply here. Similarly, the variable natural water inflow does not apply to battery systems and hydrogen storage. The hydrogen storage system's parameter definition includes details on its components, such as maximum storage charging and hydrogen injection capacity. Withdrawal capacity is determined based on data from gas storage facilities and the system's maximum output is calculated based on the efficiency of the re-electrification process. The upper limit of the energy storage capacity is determined by the maximum energy capacity, while the lower limit is set by the depth-of-discharge rate. Constraints ensure non-negativity for power plant generation, storage charging and discharging, load and stored energy. The energy stored in battery systems at the beginning of the year has to be equal to the energy storage at the end of the year.

Meanwhile, hydrogen storage facilities already contain a certain amount of hydrogen —enough to cover the winter period—and must ensure that the energy stored at the beginning of the year is at least equal to the energy stored at the end of the year. This allows flexibility for producing hydrogen for other sectors as needed. The climate data utilized restrict SH and PSH start and end filling levels. To simplify the consideration of exchanges with other countries, no exact load flows are calculated; instead, cross-border electricity exchanges are managed through virtual storage capacity. If energy is available in the virtual storage (overall import and export (transport) possibility see Appendix A equations A.19-22), electricity can be imported into Austria within the model and exported vice versa, constrained by the maximum power limit of the import/export capacities. To prevent potential grid overload during periods of high fluctuating renewable generation, the model automatically curtails a portion of the generation based on a specified grid restriction factor. Total curtailment is restricted to the power of renewable generation in each hour. Residual load is calculated by subtracting the total power generated by renewable energy sources (including run-river hydro, wind and PV) from the electricity demand of the public grid for each timestep. Further explanations of the formal description of the model can be found in Appendix A.

3.2. Scenario definition

Three scenarios are defined to cover a wide range of trajectories for electricity demand and generation capacities driven by policy objectives, electrification efforts and efficiency measures. A detailed description of the scenario definition can be found in Appendix D.

Scenario A: In the *policy* scenario, based on existing policy objectives, electricity demand is projected to rise due to the shift to EVs and heat HPs. By 2030, approximately 650000 HPs and 1 million EVs are expected in Austria, contributing to increased electricity consumption. The scenario also anticipates ongoing decarbonization efforts in various industries, leading to consistent growth in total electricity consumption.

Scenario B: There is an ambitious expansion of renewable and hydrogen capacities alongside a high degree of electrification in the *renewables and electrification* scenario. This leads to higher increases in electricity demand for space heating, cooling and electromobility. The scenario envisions a substantial rise in EV adoption and a shift towards HPs, resulting in heightened electricity demand.

Scenario C: In the *efficiency* scenario, gradual decreases in conventional electricity consumption are expected through increased efficiency measures. This results in lower electricity demand than the other scenarios, driven by energy-efficient practices and conservation initiatives. The scenario also incorporates lower market penetration of EVs and HPs, reducing electricity demand for these purposes.

Table 1 presents the installed capacities of RE, dispatchable generation and storage across all scenarios, while Fig. 3 visually represents these figures. The expansion targets for 2030 are largely determined by the EAG and thus deviate only in scenario *renewables and electrification (B)*, which emphasizes a more ambitious wind expansion. Fossil capacities still play a certain role here, as a 100 % renewable electricity target has been set, but this only counts over the year and fossil fuel generation can therefore be offset by exports of renewable electricity. Looking ahead to 2050, it is evident that an even more extensive expansion of renewables occurs in this scenario. Details on those assumptions including the respective source and storyline can be found in Appendix D. Based on the assumptions made, the hourly demand of each scenario can be met across all scenarios and weather years. For instance, if run-of-river hydroelectricity capacities are reduced due to renaturalization efforts, other renewable generators, such as wind and PV, must undergo increased capacity expansion to meet the demand. Assumptions regarding hydrogen production capacities (electrolyzers) are in alignment with the Austrian national hydrogen strategy [54]. Across all

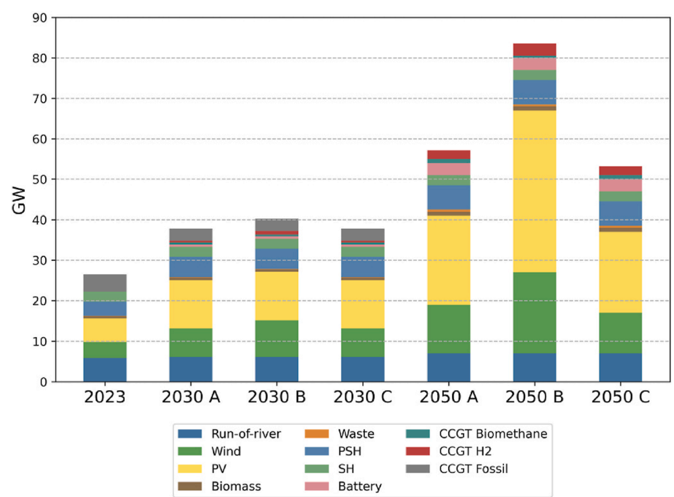

Fig. 3. Installed generation and storage capacities in Austria per scenario (Remarks: A = Policy scenario, B=Renewables and electrification scenario, C = Efficiency scenario; PSH describes the turbine capacity and combined cycle gas turbine (CCGT) H2 describes the capacity for re-electrification from the hydrogen storage units; 2023 data is from Ref. [59] as of January 09, 2024, due to its reporting dates).

Table 1
Generation and storage capacities for 2023, 2030 and 2050 in MW (A = Policy scenario, B = Renewables and electrification scenario, C = Efficiency scenario) [1,13,50,55–58].

Scenario	2023	*A Policy*		*B Renewables and electrification*		*C Efficiency*	
		2030	2050	2030	2050	2030	2050
Run-of-river hydroelectricity	5820	6100	7000	6100	7000	6100	7000
Wind	3950	7000	12000	9000	20000	7000	10000
PV	5880	12000	22000	12000	40000	12000	20000
Biomass	500	650	1000	650	1000	650	1000
Waste	80	100	500	100	500	100	500
CCGT Fossil	4230	3000	0	3000	0	3000	0
CCGT Biomethane	0	500	1000	500	500	500	1000
PSH (turbining/pumping)	3490	5000/4300	6043/5206	5000/4300	6043/5206	5000/4300	6043/5206
SH	2520	2489	2489	2489	2489	2489	2489
Storage charge/discharge capacity grid-scale battery	0	534	3000	534	3000	534	3000
Storage in/out hydrogen	0	1000/440	5000/2200	2000/880	7000/3080	1000/440	5000/2200
Import/export	8855/9100	2500	2500	6000	6000	2500	2500

scenarios, it is assumed that there will be no fossil fuel generation in the energy system by 2050. Storage technologies employed include battery storage (short-duration), PHS and SH (medium-duration) and hydrogen storage (seasonal). Further details, including assumed efficiencies and storage capacities (energy) for these technologies, are presented in Table 2.

Table 3 provides the input data on the total electricity demand in the considered scenarios. Notably, it only encompasses the load required from the electricity grid, excluding consumption from companies utilizing their plants not integrated into the public grid and household demand covered by PV and batteries. Additionally, the total electricity demand incorporates demand from HPs and EVs, alongside grid losses. However, it is important to note that the electricity consumption of the storage systems is a modeling result and must therefore be regarded as an additional component to the total load indicated.

We solve our model for three described scenarios, each pertaining to the years 2030 and 2050, under three different weather conditions, as outlined above.

4. Results

This section presents the main results of the three scenarios, namely the *policy* scenario *(A)*, *renewables and electrification* scenario *(B)* and *efficiency* scenario *(C)* within the case study of Austria. The primary focus is on the year 2050, marking the complete phase-out of fossil fuel generation and increased availability of renewable energy within the system, with a comparison between 2030 and 2050. Due to the comprehensive scenario analysis involving 18 cases (economic scenarios A, B, C; weather years 2015, 2026, 2017; target years 2030 and 2050), detailed results cannot be fully presented in this section but are available in the Appendix of this paper (Appendix D). The description is divided into three parts. First, Section 4.1 analyzes the impact of weather patterns on renewable generation and extreme weather events (such as low wind power and dark doldrums), using the *policy* scenario *(A)* as an example. Section 4.2 presents the influence of weather patterns on the overall system, underground hydrogen size and possible surplus hydrogen production, while Section 4.3 focuses on differences in storage utilization and dispatchable generation between 2030 and 2050, as well as among economic scenarios.

4.1. Influence of weather patterns on renewable generation and analysis of extreme weather events

In order to meet the established targets for achieving climate neutrality in Austria, a significant increase in wind and PV generation is necessary, see Fig. 4. The emphasis on PV is particularly noteworthy, with a substantial surge already underway. In 2022, PV contributed 3.8 TWh of electricity; however, in the outlined scenario, this must escalate to approximately 13–17 TWh (roughly a factor of 4) by 2030 and 25–27 TWh by 2050. A comparable trajectory is observed for wind power generation, starting from a higher baseline of 7.25 TWh in 2022 and rising to approximately 19–21 TWh (approximately a factor of 3) by 2030 and 30–37 TWh by 2050. The annual generation volumes fluctuate based on the weather year, necessitating a specified range of weather years for scenario development. The respective generation for wind and PV, in contrast to historical production, is illustrated in Fig. 4, clearly showing variations in production. Across the year, these are most pronounced for wind generation. In the depicted *policy* scenario, there is a difference of nearly 6 TWh between the lowest production (weather year 2016) and the highest production (weather year 2017) when calculating total annual generation. For PV, the differences are smaller, at approximately 1.6 TWh.

Table 2
Efficiencies and storage capacities (energy) [50,60–63].

Parameter	Unit	2030	2050
Maximum energy capacity PSH	GWh	1732	1732
Roundtrip efficiency PSH		0.79	0.79
Maximum energy capacity SH	GWh	757	757
Efficiency SH		0.9	0.9
Maximum energy capacity grid-scale battery storage	GWh	1.07	6
Roundtrip efficiency battery		0.9	0.9
Maximum energy capacity hydrogen	GWh	not restricted	not restricted
Roundtrip efficiency hydrogen		0.37	0.45

Table 3
Electricity load/demand input data in TWh [13,46,51,53,55,58,64,65]

Scenario	*A Policy*		*B Renewables and electrification*		*C Efficiency*	
	2030	2050	2030	2050	2030	2050
Total load/demand (excluding storage consumption)	73	79	70	83	95	80
Of which: HP	3.5	8	2.7	9	16	6.2
Of which: EV	1.8	3	1.4	6	10.3	5

The weather year 2017 is notable for several reasons: It records the highest total wind generation, the lowest PV generation and the lowest natural water inflows in PSH and SH reservoirs. While the yearly totals provide valuable insights, a more detailed breakdown is crucial for the reliable operation of a power system. Examining monthly generation reveals that although there is an overall high wind generation in weather year 2017, it drops markedly in February. This disparity is evident when comparing Fig. 5, left and right, highlighting significant monthly generation variations. Coupled with the low water flow in run-of-river hydroelectricity plants and minimal natural inflows, this can pose challenges or require increased flexibility, as analyzed further below. The substantial increase in PV electricity generation during summer months is also apparent, which in Austria coincides with peak levels of reservoir storage in summer due to snowmelt. Consequently, these PSH and SH reservoirs have reduced capacity to absorb PV electricity, necessitating alternative flexibility options. The high water levels of run-of-river hydroelectricity plants, as well as the increased inflows from May through the summer, represent a particular characteristic of the Alpine region. In warmer, drier countries without snowfall, these higher water levels occur in the opposite manner, leading to dry spells in the summer. These general trends in water flow may change in the future with increasing climate change, as found by a recent interdisciplinary study combining energy and climate modeling [58]. Using climate projections, it was shown that run-of-river hydroelectricity generation increases in winter and decreases in summer. This occurs due to reduced snow and ice formation in winter and increased drought in summer, leading to a flattening of the seasonal profile. Overall, climate change leads to a slight increase in annual generation from wind and run-of-river hydropower plants under normal weather conditions, while PV generation shows almost no differences in the model [58]. Presently, Austria faces challenges where, due to increased PV generation around midday, particularly in the first week of May 2024, run-of-river hydroelectricity plants were curtailed as surplus electricity could not be absorbed, highlighting capacity constraints [68].

Analysis of the wind patterns of the three selected weather years confirms that in weather year 2017 there was a prolonged period with low wind power lasting over eight days, with an average capacity factor of less than 10 % of the wind capacities, as depicted in Fig. 6. This occurrence, as noted by Ohlendorf and Schill [41], happens approximately once every ten years. In contrast, the other two weather years each exhibited shorter periods of low wind power events lasting fewer than five consecutive days.

In a further analysis, we examine the residual load (see Fig. 7), and identify a high positive residual load for the low wind power event

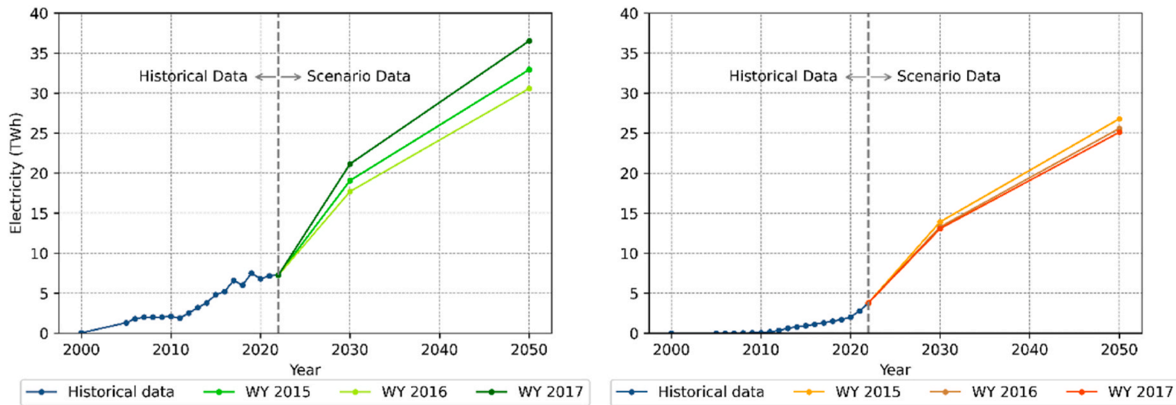

Fig. 4. *Annual wind (left) and PV (right) generation from 2000 (historical data, [66,67]) up to 2050 (simulation results, policy scenario (A)).*

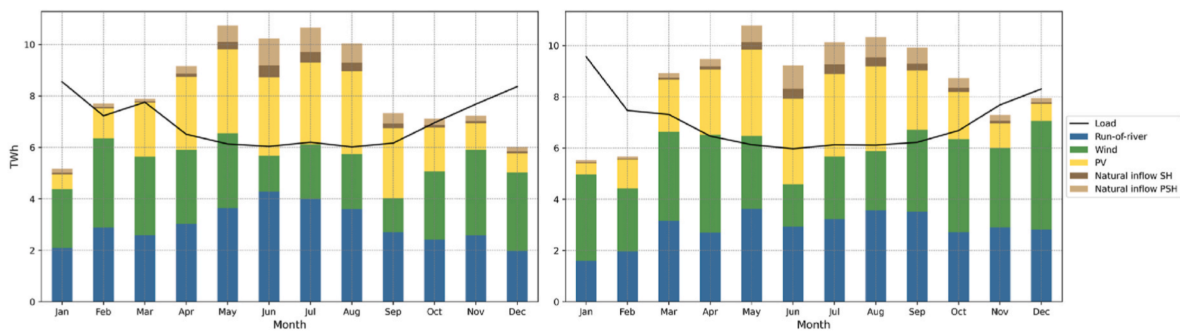

Fig. 5. Monthly variable renewable generation and natural water inflows in 2050 with the underlying weather year 2016 (left) and 2017 (right).

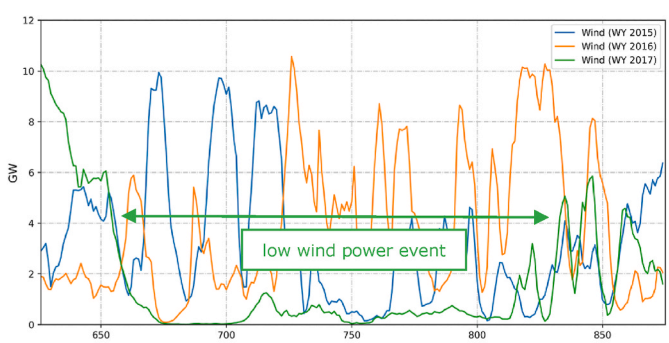

Fig. 6. Low wind power event over eight days with an average capacity factor of less than 10 % in weather year 2017 in comparison to weather year 2015 and 2016 in the same period.

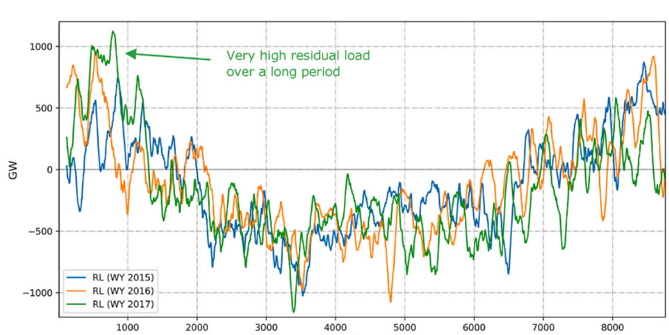

Fig. 7. Annual residual load for the policy scenario (A) 2050 and three regarded weather years (smoothed with a 5-day moving average).

defined earlier in the weather year 2017. This finding aligns with Suna et al. [46]. Alongside the noted low wind generation, temperatures are also low, resulting in high heating demand and thus electricity demand for HPs, as well as reduced PV generation due to fog and low inflows in hydro reservoirs, resulting in so-called dark doldrums. Regarding hydraulic conditions, simulations from the PECD [50] were utilized, revealing that during this period in weather year 2017, the lowest storage levels and water flows were recorded. This was also confirmed by E-Control, stating that at the beginning of the year 2017, the available storage capacity was particularly low compared to long-term averages [69]. All these factors are reflected in the residual load, as temperature data are also factored into HP electricity demand, depending on the weather year. It should also be noted that this analysis of the residual load only covers Austria. European climatic interactions are not considered here. However, the dark doldrum in 2017 was also observed in Germany, suggesting a certain correlation of conditions [70].

In summary, the weather year 2017 can be classified as an outlier year within the regarded three weather years due to the significantly lower water inflows and wind generation in January and February compared to the other two weather years. Additionally, relatively low temperatures in weather year 2017 contribute to an overall increasing demand for electricity to operate HPs compared to the other two scenarios. This divergence was also observed in the optimization results. When applying weather year 2017 for optimization, increased use of storage and dispatchable generators is necessary during winter months. Thus, one extreme year and two normal years were included in the optimization.

4.2. Influence of weather patterns on the overall fully renewable electricity system, possible surplus hydrogen production and underground hydrogen storage size

To analyze the interplay between renewable generation and respective storage technologies in a fully decarbonized power system, Fig. 8 illustrates the monthly total generation for 2050 per weather year, exemplified by the *policy* scenario *(A)*. In this graph, energy amounts utilized for electricity generation by the storage technology (PSH, SH, battery and hydrogen) are depicted positively, while energy amounts to charge the storage (consumption) are plotted as negative values. Both energy amounts used for discharging and charging, are labeled identically for simplification. The dark doldrums identified in previous analyses in January of weather year 2017 are clearly visible in this representation. Here, compared to other weather years, the necessary load coverage is highest, accompanied by the lowest input of run-of-river hydroelectricity, wind and PV. To cover the load, all available storage capacities, renewable dispatchable generators and available import quantities are utilized to the fullest extent, as determined through sensitivity analysis by adjusting parameters. Reducing capacities led to periods of undercoverage. If these capacities were not available in the model, other dispatchable renewable generators, such as biomethane with higher power capacity, would need to be implemented. Regarding the optimization explanation, PSH and SH are limited based on initial water levels at the start of the year, as simulated by the PECD model, which aligns with real-world conditions as demonstrated in the preceding section. Biomass and biomethane are constrained by their installed capacities, while batteries are also restricted to energy capacities. Import and export capacities are modeled as virtual storage, with their full energy capacity available at the beginning of the year. Hydrogen storage is modeled as a special case, assuming unlimited availability with no restrictions on initial hydrogen quantities (energy component of the storage), provided that at least the initial storage quantity is maintained by the end of the year, with the potential for additional accumulation. Limitations on hydrogen usage to cover the dark doldrums stem from the re-electrification plant's power component. Hydrogen production for storage via electrolysis occurs exclusively during summer months (power-to-gas), with significant variations in the extension of hydrogen production periods into autumn across different weather years. In weather year 2015, surplus renewable generation is considerably lower, with hydrogen production primarily occurring from April to October, whereas in the other weather years, hydrogen production can also extend into March and November. The seasonality of hydrogen utilization in the power system is thus evident. The same occurs with dispatchable renewable generation, which is prominently utilized during winter months.

To provide more detailed analysis with respect to the different economic scenarios (*policy (A)*, *renewables and electrification (B)* and *efficiency (C)*), Fig. 9 illustrates the total electricity generation per technology for the year 2050 across all developed scenarios. It is evident that in all scenarios, biomethane is exclusively used in weather year 2017 due to the necessary load coverage in winter. Biomass and waste are also increasingly utilized in weather year 2017, but also in two scenarios across all weather years. In scenario *renewables and electrification (B)*, these capacities are no longer needed in weather years 2015 and 2016 due to the generally higher renewable generation and higher utilization compared to other scenarios. Alongside increased generation, the higher utilization of PSH and increased import and export possibilities in this scenario also play a role. This means that a higher level of balancing can be covered by alternative flexibilities. Total generation must also be higher in this scenario due to the higher electricity demand modeled. It is also evident in scenario *efficiency (C)* that lower flexibilities are required when the electricity demand is lower.

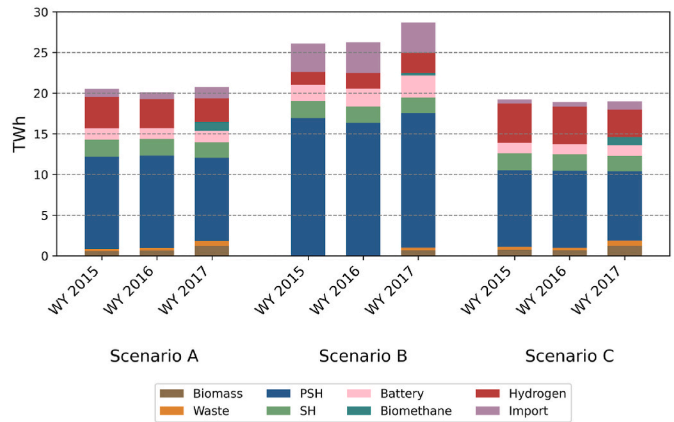

Fig. 9. Total yearly electricity generation in 2050 for each scenario and weather year in TWh.

The utilization of storage is also dependent on weather conditions. The respective state of charge of underground hydrogen, PSH and battery storage in each hour over the year, depending on the weather year in 2050, is depicted in Fig. 10. In the case of hydrogen storage, it is apparent that the storage maintains a relatively constant accumulation of hydrogen over the summer months. This is attributed to the characteristic of a high seasonal surplus in the middle of the year in all weather years. However, the amount of hydrogen needed for reconversion in winter depends on the underlying weather year. In weather year 2017, a considerable amount is required at the beginning of the year, but significantly higher quantities remain in storage by year-end. These additional amounts of hydrogen remaining in the storage signify increased renewable capacities in 2050. In 2030, almost all generated capacities were required for reconversion.

In the other two weather years, the storage level is more balanced. Approximately equal amounts of hydrogen are needed in the winter

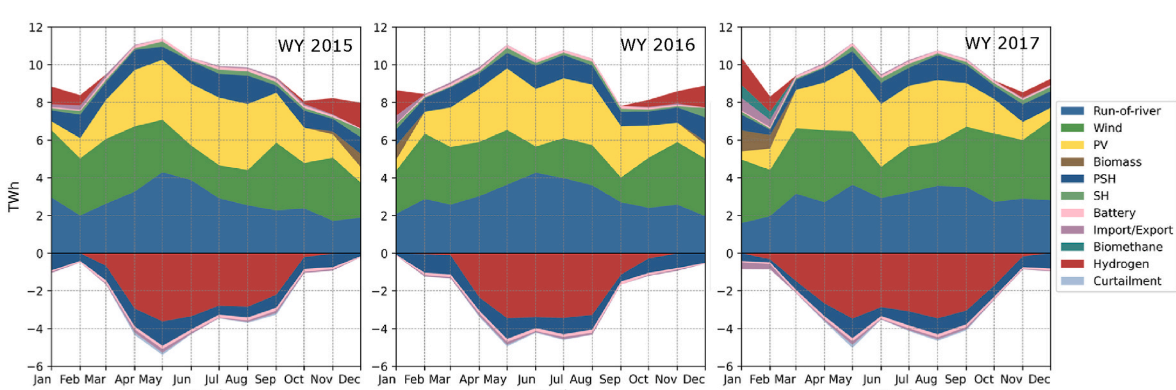

Fig. 8. Total electricity generation (positive) and consumption (negative) per month of the year 2050 per weather year in TWh (policy scenario (A)).

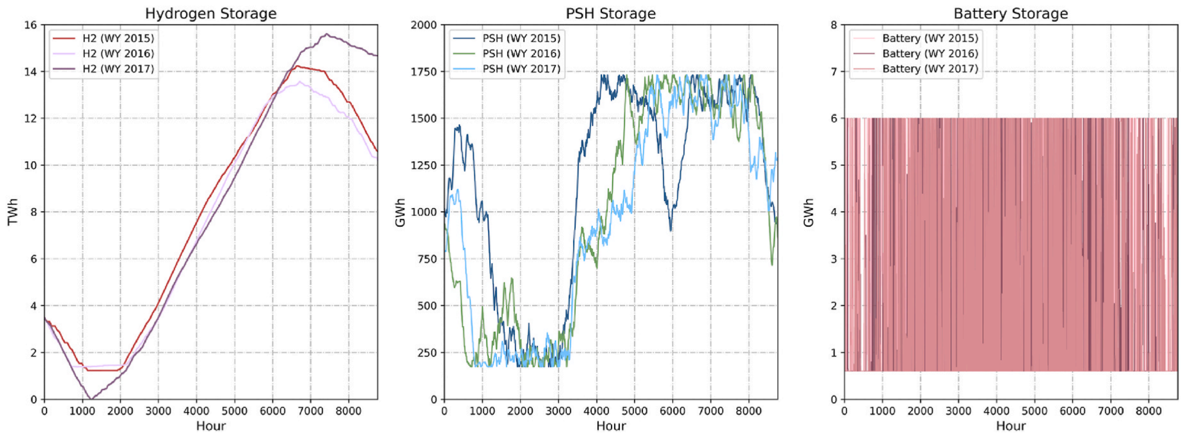

Fig. 10. State of charge of underground hydrogen (left), PSH (middle) and battery (left) storage in 2050 (policy scenario(A)).

months at the beginning and end of the year. PSH also exhibits strong seasonality due to natural inflows, resulting in consistent intra-year patterns in storage levels. The storage is discharged to the maximum depth during hours 2000 to 3000 in all weather years, then recharged with natural inflows occurring due to snowmelt. Typically, the storage reaches its peak level in early September and is subsequently utilized to varying extents for winter demand coverage. In weather year 2015, the highest initial water levels are available, leading to a slower discharge and faster recharge. Additionally, a relatively deep discharge of the storage occurs around hour 6000. From weather year 2016–2017, the summer storage levels are replenished more slowly but remain at higher levels. Besides the seasonal pattern, the shorter to medium-term fluctuations of PSH are also evident. This is compared to hydrogen storage, which is exclusively used for seasonal coverage and exhibits no shorter-term fluctuations. Battery storage, on the other hand, is used solely for short-term balancing of intraday fluctuations, such as balancing PV surplus during midday. This is attributed to the energy-to-power (E/P) ratio in the model assumptions. Since batteries can be most cost-effectively utilized for rapid, short-duration storage, an E/P ratio of 2 was employed in this case. If battery storage were not available to the extent modeled, the other two storage technologies would also need to cover short-term balancing, altering their state-of-charge profiles.

As discussed earlier, the model also allows for hydrogen production aside from reconversion if this is cost-optimal. The amount of hydrogen remaining after deducting the demand in the electricity sector largely depends on climatic conditions (weather year 2017 has the highest production potential due to the surplus in the second half of the year) and the scenario design, see Fig. 11. In scenario *renewables and electrification (B)*, there is the greatest potential for hydrogen production, as it involves the most significant expansion of renewable generation overall. Therefore, despite the overall higher demand, a larger summer surplus is available. In total, 26.10–30.11 TWh_{H2} are produced in this scenario. Of this, 23.14–26.23 TWh_{H2} remain as surplus for use in other sectors or as backup capacity for other weather years, as the demand for reconversion as seasonal compensation is lower in this scenario. In scenario *policy (A)*, hydrogen production amounts to 12.21–15.6 TWh_{H2}, with a surplus of 6.71–11.17 TWh_{H2}. In scenario *efficiency (C)*, production amounts to 10.24–12.68 TWh_{H2}, with a surplus of 3.12–7.51 TWh_{H2}. These quantities are heavily dependent on the planned expansion of wind and PV. The higher these expansions, the greater the quantities of hydrogen

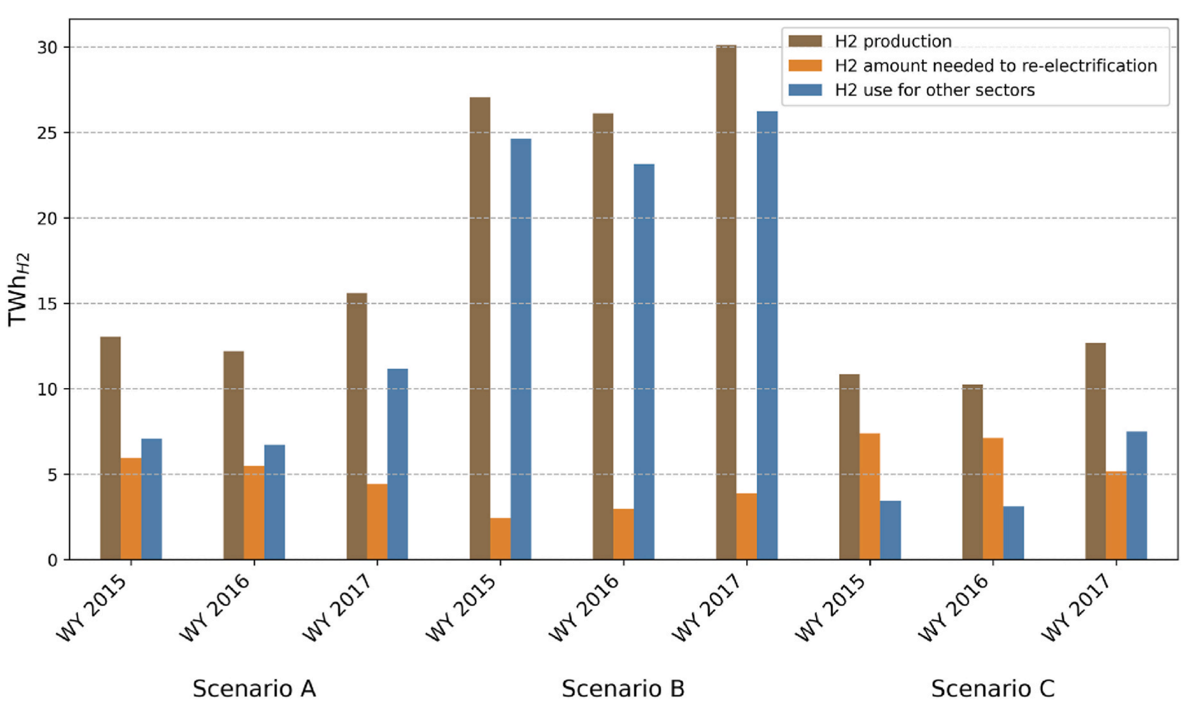

Fig. 11. Production, re-electrification and surplus amounts of hydrogen for each scenario and weather year in the year 2050.

production that can also be utilized in other sectors.

With the specific model design (the initial quantity of hydrogen available was not restricted), it was demonstrated that even if surplus quantities remain in storage for the next weather year, this does not alter the model results, as reconversion capacities are the limiting factor in our cases. The necessary storage size (energy component) of the hydrogen storage is determined by not restricting the storage volume. This amounts to the maximum filling level minus the minimum filling level. However, as hydrogen storage behaves strictly seasonally, storing relatively constant amounts to then release them consistently results in the required storage size being identical to the total hydrogen production, as illustrated in Fig. 11. These sizes are thus in the range of approximately 10–30 TWh_{H2}. For underground hydrogen storage, current installations in Austria are limited to a pilot plant. However, as an alternative, the current natural gas storage capacities in Austria amount to approximately 94 TWh_{NG}, equivalent to approximately 25 TWh_{H2} [71]. Therefore, the demand in scenarios *policy (A)* and *efficiency (C)* could be entirely met by existing storage facilities converted to hydrogen. Additional storage would need to be built for scenario *renewables and electrification (B)* if the total hydrogen quantities were to be stored. However, these are only theoretical considerations because, in the case of alternative utilization of hydrogen, deliveries would already be made intrayearly, thus relieving storage facilities. The total demand for reconversion, which must be stored seasonally, would amount to only up to 7.4 TWh_H and could thus be adequately covered by the currently existing storage capacities.

4.3. Differences in storage utilization and dispatchable generation between 2030 and 2050

In this section, the characteristics of storage (utilization of charging and discharging, total charged amount) will be analyzed in more detail based on the *policy* scenario *(A)*, comparing the target years 2030–2050. The utilization of storage changes with the target year (2030, 2050) and depends on the weather year. Utilization refers here and in Fig. 12 to the full-load hours of discharging for storage technologies and for other technologies, it refers to the full-load hours of electricity generation. To simplify the description, full-load hours are referred to as such for all technologies. The clear trend that full-load hours decrease in 2050 for almost all technologies is due to the availability of larger amounts of renewable energy, but because of the limited correlation between fluctuating wind and solar power generation and hourly demand, increasing capacities of these technologies do not lead to a linear decrease in residual load. In 2050, fluctuating renewable energies replace a large part of fossil fuel generation (given the phase-out of flexible fossil fuel power plants as model input) but hardly reduce the flexibility requirement (maximum power) of the systems, necessitating other flexibilities with higher capacities to balance the load. Therefore, significant backup capacity must be maintained for a few hours per year in this case. Truly pure backup capacities are in biomethane in 2050; full-load hours are zero in all weather years, with only slightly over 1100 h in weather year 2017.

Also interesting is the general utilization depending on the weather year, as shown in Fig. 12. Biomass in 2030 in weather year 2015 and 2016 ranges between 3500 and 4000 full-load hours, while only 700 full-load hours are required in weather year 2017. This changes in 2050; in weather year 2015 and 2016, only 550–650 full-load hours are needed, but in weather year 2017, the utilization increases to 1200 full-load hours. Due to the absence of flexible fossil fuel generation, other flexibilities become more important in extreme years. Conversely, PSH exhibits a counter-trend, with higher turbine utilization in weather year 2015 and 2016, but with only a slight reduction in deployment from 1760 to 1690 full-load hours in weather year 17. Additionally, it should be noted that the total available water volumes from natural inflow and the initial storage level depend on the underlying hydraulic model for PSH, which also has an influence on the possible utilization of storage. Conversely, batteries show a slightly declining trend in utilization (approximately 100 fewer full-load hours) in all scenarios. Similarly, in hydrogen re-electrification (discharging), there is a significant decline in full-load hours of up to 1380 h.

With increasing decarbonization in the system, storage and other power plants focus on covering the positive residual load, which decreases as the share of renewable generation in the system increases, but the installed capacities must remain available. Extreme years are particularly relevant here because some of the implemented capacities generate few full-load hours during such events (in the model, weather year 2017) but none at all in other years. However, without these capacities, shortages would occur in certain periods, as tested in the model. Therefore, the reduction of flexible capacities in the system due to lower utilization is not feasible as long as the condition that demand must be met every hour remains included.

Examining the charging hours of storage technologies in Fig. 13 reveals a clear trend, similar to that observed in the discharging hours for battery storage. This is expected based on the model assumptions for batteries since only as much can be stored as was previously stored. The trend for PSH also aligns in the opposite direction (except for weather year 2017, where the utilization of pumping power increases slightly from 1330 to 1440 full-load hours) with overall lower utilization of pumping power compared to turbine power of the storage, as the reservoirs can also be filled by natural inflow. However, the seasonal component is evident with PSH. Since more electricity from renewables will be available in 2050, especially in summer, PSH will increasingly store it to utilize in periods of scarcity. This is particularly pronounced with hydrogen, as storage volumes are not limited in the model. Increasing amounts are stored, except for weather year 2015, some of which are surpluses that can be used in other sectors or remain in storage for subsequent years. Hence, the overall range of total charging (power to gas) utilization (3200–4460 full-load hours) in both 2030 and 2050 is significantly higher than discharging (re-electrification) utilization (1300–3130 full-load hours).

The following illustrates how the respective storage technologies function and how they will change from 2030 to 2050, using the policy scenarios and weather year 2017 as examples. Figs. 14–17 show the charge and discharge profiles as well as the resulting storage levels for each technology.

Long-durationstorage, in our case, hydrogen storage, is primarily

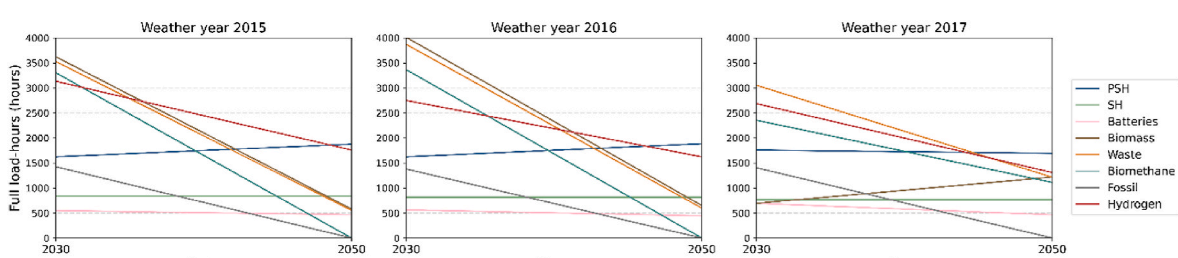

Fig. 12. Utilization of technologies (full-load hours, discharging hours) in comparison from 2030 to 2050 and weather year (policy scenario (A)).

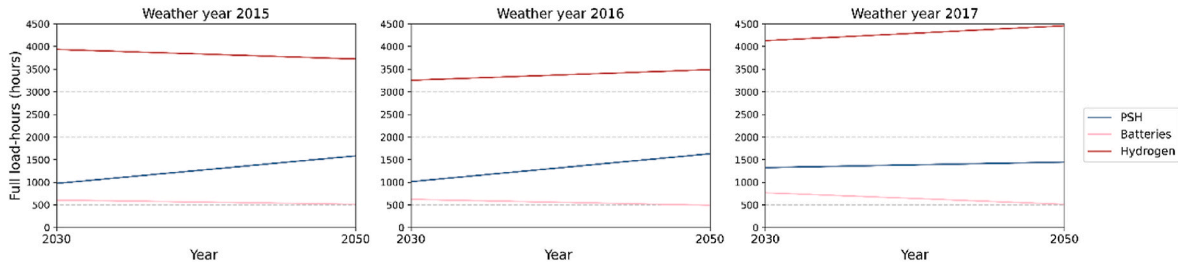

Fig. 13. Charging hours or storage technologies in comparison from 2030 to 2050 and weather year (policy scenario (A)).

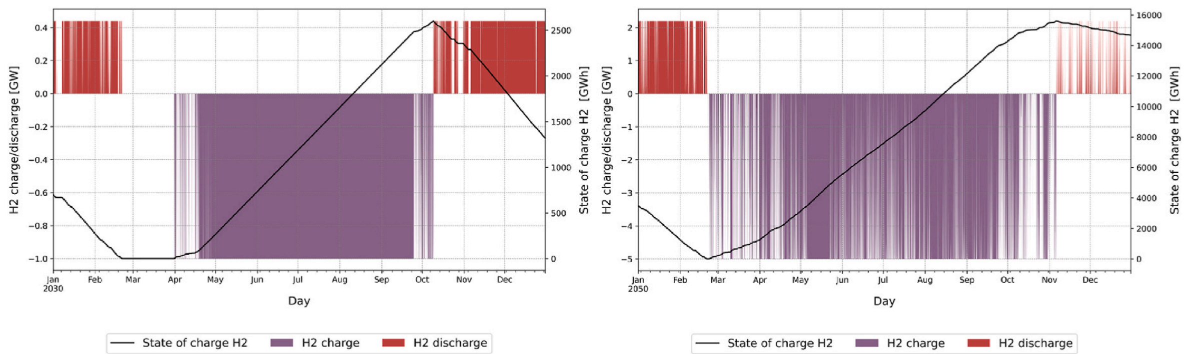

Fig. 14. Hydrogen charge and discharge profiles and the resulting state of charge of storage in 2030 (left) and 2050 (right) (policy scenario (A), weather year 2017).

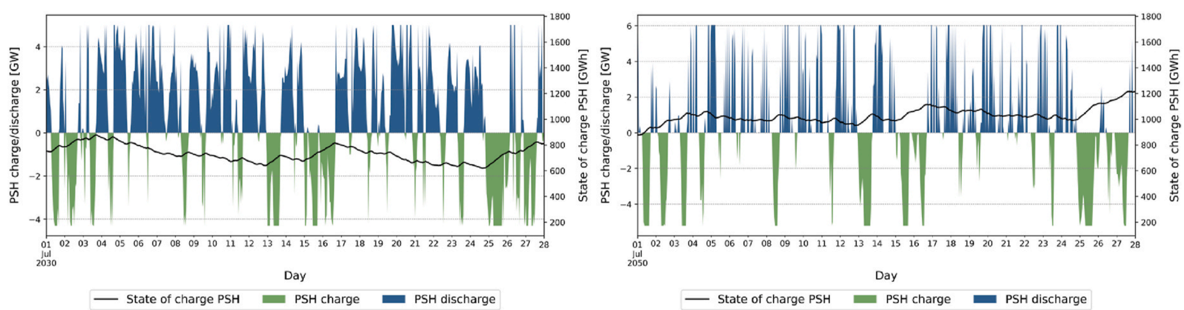

Fig. 15. PSH charge and discharge profiles and the resulting state of charge of storage over 28 days in 2030 (left) and 2050 (right) (policy scenario (A), weather year 2017).

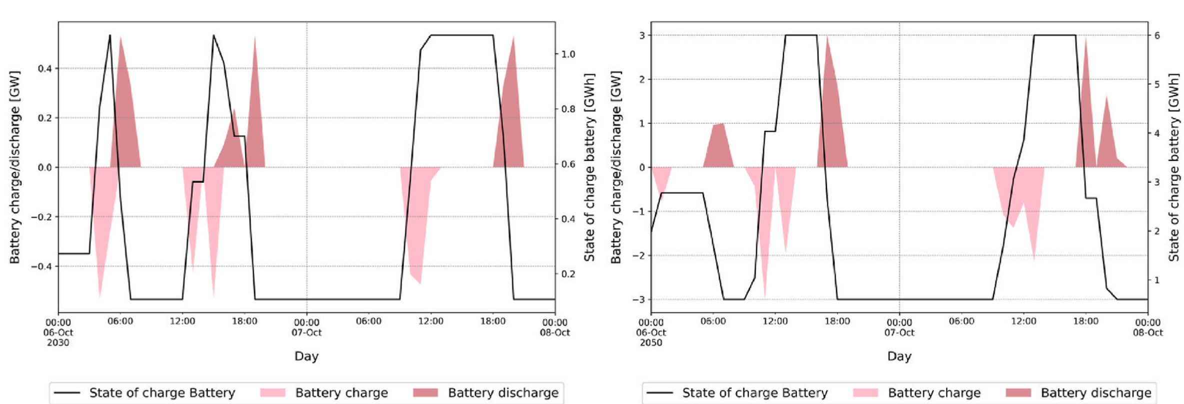

Fig. 16. Battery charge and discharge profiles and the resulting state of charge of storage over two days in 2030 (left) and 2050 (right) (policy scenario (A), weather year 2017).

used to shift large amounts of energy between seasons (in the Austrian electricity system, from summer to winter). Fig. 14 demonstrates this behavior, confirming the system design where hydrogen storage is intended for long-duration storage. Hydrogen discharge is only required in the winter months, while the storage is charged exclusively during the summer months. Therefore, the long-duration storage cycle occurs only

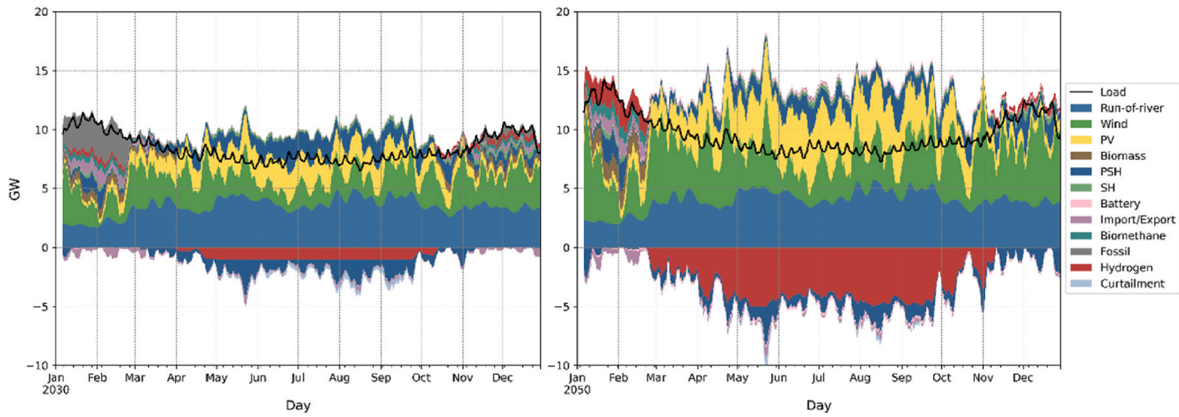

Fig. 17. Electricity generation and consumption throughout the years 2030 (left) and 2050 (right) (smoothed with a 5-day moving average, policy scenario (A)).

once a year, as seen clearly in the state of charge curve. In 2030, electrolysis capacities operate at nearly full capacity to store hydrogen from mid-April to mid-September. Before and after, storage reacts and operates flexibly based on over and undercoverage of the residual load. In 2030, the re-electrification capacities are also more utilized compared to 2050, primarily from the end of February to the end of October.

In 2050, the initial utilization is approximately the same (due to extreme conditions in weather year 2017), but there is lower utilization of re-electrification (due to other flexibility options), starting only in November, leading to higher storage levels compared to 2030. Additionally, throughout the summer, electrolysis capacities are more flexible as higher capacities are available, allowing for higher amounts of electricity to be converted into hydrogen. Specifically, the comparison of electricity inputs for charging (power-to-gas) is 4.13 TWh in 2030 and 22.29 TWh in 2050 (utilization 4130 to 4460 full-load hours). In 2030, 1.18 TWh and in 2050, 2.88 TWh of electricity are provided to the system through discharging (re-electrification) of hydrogen storage in 2050 (utilization 2690 to 1310 full-load hours).

PSH also exhibits a certain seasonal component, as shown in Fig. 10, depicting the annual state of charge profile; however, it primarily addresses short and medium-term requirements, as seen in Fig. 15. Here, the profile over 28 days is displayed to visualize these shorter charge and discharge cycles. Throughout the year, it is observed that, contrary to the other two weather years, in weather year 2017, the times of utilization for PSH discharging slightly decrease and within the specific observation period, the storage level in 2050 is higher (a possible reason being the slightly lower utilization of the discharging capacities/turbines, from 1760 to 1690 full-load hours). Overall, due to higher available power capacities in 2050, a greater amount is discharged (turbining), namely 10.23 TWh compared to 8.78 TWh in 2030. The electricity inputs for charging (pumping) amounted to 5.70 TWh in 2030 and 7.53 TWh in 2050, with a utilization of 1330 (2030) and 1450 (2050) full-load hours.

Battery storage, on the other hand, is utilized for short-duration daily balancing due to its high power ratio and efficiency but limited energy capacity, as defined per model design. Fig. 16 illustrates, for a two-day interval, that batteries are frequently used to provide small amounts of stored energy and are cycled one to two times per day, often reaching their full installed energy capacity. The overall utilization of battery storage decreases slightly from 2030 to 2050 (690–460 full-load hours discharging and 771 to 516 full-load hours charging), but the total energy quantities increase due to higher installed power and energy capacity. Specifically, charging amounts to 0.41 TWh in 2030 and 1.55 TWh in 2050. In 2030, 0.37 TWh and in 2050, 1.39 TWh of electricity are provided through the discharging of battery storage.

The annual dispatch in the *policy* scenario *(A)* (Fig. 17 smoothed with a 5-day moving average) illustrates once again the seasonality of renewable generation (blue, green and yellow) with the highest generation levels in the summer months, thus also indicating the greatest power-to-gas (red) production potential. The difference between 2030 and 2050 is very clear, showing a massive increase in capacities in the model. However, in both years, the generation levels of variable renewable generation are not sufficient to cover the total demand. In 2030, fossil fuel power plants (grey) are mainly used for this purpose, while in 2050, everything is covered by storage and flexible renewable generation. This requires a seasonal shift in generation from summer, when renewable resources (mostly PV and run-of-river hydroelectricity) are abundant, to winter, when combined resources are relatively scarce. PSH competes to some extent with hydrogen storage, as they also cover a certain proportion of the seasonal demand, as seen in the shared charging periods of PSH (blue) and hydrogen (red) in the summer months. Batteries (pink) are routinely charged and discharged in small quantities throughout the year. Curtailment (light blue) mainly occurs in the summer months during peak loads.

4.4. Limitations

The model is subject to certain limitations and constraints due to the extensive scenario analysis, which includes economic scenarios, target years weather conditions (18 cases). One notable restriction is the adoption of a "copper plate" approach, where Austria is modeled as a single node, neglecting regional and network-specific constraints. Welder et al. [62] recommend situating electrolyzers in proximity to surplus electricity sites to obviate the need for additional grid expansion. In order to account for network restrictions, the model implements curtailment if an exceptionally high share of renewables is fed into the grid in a specific hour. We acknowledge, however, that adapting the network infrastructure is imperative to fully harness the potential of these storage technologies.

Additionally, the model abstracts from a detailed representation of flexibility restrictions in thermal generators. Power plants and storage technologies are aggregated as a unified capacity within the model, portraying the Austrian electricity sector in a simplified manner as cumulative national capacity per technology. Particular emphasis should be placed on the simplification regarding PSH, as an available storage capacity was modeled without separately modeling individual power plants, including their upper and lower reservoirs, which is indeed a restriction in reality. This is because pumping can only occur if sufficient water is available in the lower reservoir. Additionally, PSH plants vary significantly in terms of their power and energy components. Including PSH as individual plants without the chosen level of aggregation was not feasible due to the number of scenario runs and data availability and is also in line with Schill [72] and Sousa [26]. No exact load flows and no exact exchange with other countries were modeled; here, too, the possible total exchange capacities are combined as a virtual import and export storage facility in order to allow a certain amount of balancing in the model. Moreover, it is important to acknowledge that, alongside storage, demand-side management (DSM) is an important flexibility component. While DSM has been integrated into the load profiles to a certain extent, it does not constitute a separate optimization variable in the model. This represents a limitation in the current version of the model and should be considered in future iterations.

Furthermore, the assumption of a perfectly efficient market and perfect competition implies that generators with the lowest variable costs are always ranked first within the merit order structure, with one market and trading horizon in an energy-only market. Balancing markets were not considered. The model assumes perfect foresight, which means that there are no forecast errors for electricity generation within any one year, thus eliminating uncertainties. To avoid this to a certain extent, three weather years were considered, aiming to achieve representativeness in capturing climatic variability, but in the knowledge that all uncertainties in RE generation could not be captured this way. Another limitation is that despite different weather patterns, climate change was not included in this paper. While the assumptions made facilitate the modeling process, it is crucial to acknowledge that they may also lead to an overestimation of the flexibility potential within the overall power system, despite advancements in renewables forecasting and discussions about shorter trading horizons.

5. Conclusions and outlook

In this paper, three different scenarios—*policy, renewables and electrification* and *efficiency*—were examined to cover some possible future outlooks for the decarbonization of Austria's electricity system using high shares and varying degrees of renewable energy expansion. Despite certain scenarios and model calculations being available until 2030 in the literature, policies (100 % renewable electricity) and conditions regarding emission reductions (carbon neutrality) are changing, necessitating calculations with new scenarios and models. This requires a more detailed view of storage systems, with a focus on the dynamics and capacity utilization of different storage technologies. Specifically, battery storage is utilized for short-duration daily balancing due to its high power ratio and efficiency but limited energy capacity due to high investment costs, as per model design. PSH appears relevant primarily for short-to medium-duration storage needs, but it also exhibits a seasonal component due to Austria's large reservoir capacities and seasonal water inflows. Hydrogen storage is required for seasonal balancing. The paper also highlights a focus on long-term development, aiming for a fully transitioned electricity system using renewable technologies and increased electrification on the demand side. These scenarios were optimized through the analysis of optimal dispatch strategies under certain assumptions.

The analysis has shown that a fully decarbonized energy system is feasible, provided that policy goals are implemented accordingly and generation expansion occurs to the extent shown in the present model. The future energy system will significantly differ from the current one, with the main distinction being the absence of fossil fuel generation, which must be replaced by a combination of renewable generation and long-duration storage. As neighboring countries are also facing the decarbonization of their energy systems, sourcing imports of renewable energy from these countries could become more challenging (and costly) in the future, especially during winter months, as coal power capacities are phased out. These potential assumptions are accounted for in two of the scenarios presented here, with import/export exchanges being more strictly limited (modeled in our case as artificial storage) to demonstrate that a transition would still be possible even with more restrictive assumptions.

Another significant finding of this paper is the influence of weather patterns on renewable electricity generation and consequently, on the utilization of storage technologies and dispatchable generators. Using weather data from different years results in significant differences in capacity utilization of storage and the required integration of additional dispatchable renewable capacities. These weather patterns can be categorized into seasonal trends, such as higher PV and run-of-river hydroelectricity generation in summer compared to winter and extreme events. Extreme events include prolonged low wind events (five consecutive days with an average capacity factor of less than 10 % according to Ohlendorf and Schill [41]), low PV generation, low water levels and natural inflows coupled with low temperatures and increased use of HPs, which are integrated into our model using data from weather year 2017. Consequently, we treat the two weather trends separately and define their implications and requirements on the energy system, as achieving climate neutrality requires a significant increase in generation from wind and PV sources compared to current levels in electricity systems. This amplifies the impact of weather fluctuations and additionally, no flexibilities are available from fossil flexible power plants.

Regarding the general trend, once fossil generation is no longer available, seasonal balance can only be achieved through long-duration storage (storing the negative residual load). An initial trend is already evident in Austria, where the massive expansion of PV has led to generation reaching peak levels, but flexibility is still insufficient. Consequently, run-of-river hydroelectricity plants have been massively curtailed on those exemplary days [68]. Although this is a crucial flexibility, it is not sustainable in the long term if the ultimate goal is complete decarbonization. Short-duration solutions like battery storage, improved demand-side management and grid expansion could mitigate PV peaks during the day, but long-duration storage is necessary for storing this surplus for winter periods. Despite Austria having significant PSH capacities, they are insufficient for this purpose. This task is fulfilled in the present model by underground hydrogen storage. Power-to-gas, underground hydrogen storage and re-electrification through CCGT provide seasonal balancing options for the electricity system.

The model demonstrates that in the assumed scenarios, hydrogen storage (or electrolysis facilities) can offer the required flexibility to store significant amounts of this negative residual load as hydrogen. For the seasonal storage of electricity surpluses or hydrogen, existing underground hydrogen storage capacities must be utilized. Domestic natural gas storage capacities (94 TWh_{NG}, equivalent to approximately 25 TWh_{H}) are more than sufficient for balancing a renewable electricity system seasonally, as demonstrated in the current model based on hydrogen storage levels. The regional aspect of expanding power-to-gas/electrolysis facilities, including storage, becomes essential here. If well-planned and located in close proximity to surplus electricity generation sites, coupling electricity to gas provides the electricity system not only with additional temporal but also spatial balancing options through the coupled gas infrastructure, further alleviating strain on the electricity system. The magnitude of the electricity surplus should be the primary criterion for site selection. Reconversion facilities should be situated near demand centers for the same reason.

Currently, hydrogen storage and seasonal PSH (such as the Limberg facility in Austria [73]) are the two most discussed technologies for long-duration energy storage. Due to the low efficiencies of hydrogen and topographical constraints associated with PSH, requiring vast reservoirs, other technologies for seasonal storage are increasingly under discussion, such as gravity energy storage [74], pumped heat energy storage [75], or general seasonal thermal storage [76]. Integrating additional technologies for seasonal storage, along with their respective technical characteristics, into future models will be important.

The second important conclusion regarding climatic conditions pertains to extreme years. In these years, capacities of storage and renewable generators such as biomass and biomethane are necessary, which are scarcely needed in other average years as the load can be covered by storage technologies. Biomethane, to give an example, in the model with the target year 2050 in all scenarios examined, is dispatched only in weather year 2017 (outlier year) and is thus a pure backup capacity for the occurrence of such an event. The capacities included in the modeling are essential. With lower system flexibility capacities, there would be hours of undercoverage if the other model parameters remained the same. The use of biomethane is only an example in the model; this capacity could just as well be covered by additional capacities of hydrogen re-electrification, but it exemplifies the problem of low to no utilization of some flexible capacities in a fully renewable electricity system. There is already much discussion in the literature on how operators of such storage or power plants should be remunerated, whether this should be market-based with very high scarcity prices so that the operators can earn enough in the few hours to keep these technologies available or whether it should be done through capacity markets or other ideas. What is certain, however, is that this requires strategic planning to ensure that the expansion of renewable generation goes hand in hand with planning the necessary flexibilities to prevent stranded assets that can no longer be used and to maximize utilization of installed storage capacities. The scenarios defined in this paper provide a first insight into how a distribution of capacities under the chosen boundary conditions might look. Through previous sensitivity analysis, in all scenarios, only as many capacities of storage and dispatchable renewable generations were implemented as required to ensure system reliability even in extreme weather years.

Furthermore, although not directly addressed in the paper, it is important to consider other flexibility measures, such as demand-side options, demand response, or grid expansion, as these factors partly compete with each other. Additionally, in future model extensions, efficient coupling with other sectors should be integrated to utilize potential surpluses for purposes beyond the hydrogen integration included in the paper (for example for other power-to-x solutions). In this case, this coupling would affect parts of the electricity not needed in the power system, thus not unlocking additional storage opportunities but aiming for the most cost effective and efficient utilization of negative residual load and potential consumption shifting. Further extension could also be made on the demand side, with specific strategies for mobility demand management (e.g., better load management, vehicle-to-grid, etc.) as well as increased flexibility of small scale HPs, although the opportunities here tend to be more limited [77].

In this paper, generation profiles of variable renewable generation were developed based on historical profiles. Although the input data were based on different weather years, the model assumes perfect foresight for optimizing storage and dispatchable generators. In future work, it would be important to include forecasting to make the modeling more realistic. Prediction, especially for wind and over longer time horizons using weather forecast models, is a challenging task due to the rapid movements in the atmosphere. However, the electricity market relies heavily on such forecasts. Therefore, integrating such models into electricity model analyses would be advantageous. Additionally, the influence of climate change on the power system is increasingly significant and coupling climate models with power system models will also be essential in the future, albeit with significant challenges due to the enormous volume of data involved.

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CRediT authorship contribution statement

M. Sayer: Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Data curation, Conceptualization. **A. Ajanovic:** Writing – review & editing, Supervision, Project administration, Funding acquisition, Conceptualization. **R. Haas:** Writing – review & editing, Supervision, Methodology, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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APPENDIX

A Formal description of the model

The following section is an addition to Chapter 3.1 and provides a more detailed explanation of the model description.

The load variable (electricity demand) includes separate hourly time series for HPs ($P_{HP}, in\ MW$) and EVs ($P_{EV}, in\ MW$), which were modeled as electric loads through the AIT load generator [51,53] and other load ($P_{other}, in\ MW$), based on historical data of representative weather years:

$$P_{load,t} = P_{HP,t} + P_{EV,t} + P_{other,t}\ \forall t \in T\ (\mathrm{MW}) \tag{A.1}$$

The power of renewable electricity includes run-river hydro ($P_{river}, in\ MW$), wind ($P_{wind}, in\ MW$) and PV ($P_{PV}, in\ MW$):

$$P_{RE,t} = P_{river,t} + P_{wind,t} + P_{PV,t}\ \forall t \in T\ (\mathrm{MW}) \tag{A.2}$$

The calculation of electricity generation from wind and PV sources involves multiplying the hourly historical power factors ($\mathrm{f}_{\mathrm{wind/PV}}, in\ MW/\ MW$) of different weather years by the installed capacities of wind and PV systems ($\mathrm{P}_{\mathrm{wind/PV}}\ max, in\ MW$), which vary across different scenarios. Enhanced wind turbine efficiency has been considered in this calculation.

$$\mathrm{P}_{\mathrm{wind,t}} = \mathrm{f}_{\mathrm{wind,t}}\ \mathrm{P}_{\mathrm{wind}}\ \max \forall t \in T\ (\mathrm{MW}) \tag{A.3}$$

$$\mathrm{P}_{\mathrm{PV,t}} = \mathrm{f}_{\mathrm{PV,t}}\ \mathrm{P}_{\mathrm{PV}}\ \max \forall t \in T\ (\mathrm{MW}) \tag{A.4}$$

Hydroelectric power plants are aggregated into run-of-river hydroelectricity, SH and PSH capacities. Run-of-river hydroelectricity is included in the must-feed renewable capacities, while SH and PSH capacities are modeled as dispatchable electricity storage, restricted by natural inflows derived for different meteorological conditions and the filling levels of water reservoirs.

Some constraints define that the hourly generation of all aggregated dispatchable power plants and storage technologies has to be lower or equal to the installed capacity ($P_i\ max, in\ MW$) and the maximum storage charging ($P_{sto,in}\ max, in\ MW$) and discharging power ($P_{sto,out}\ max, in\ MW$):

$$\sum_{i \in I} (P_{i,t} - P_i\ max) \leq 0\ \forall t \in T\ (MW) \tag{A.5}$$

$$\sum_{sto \in STO} (P_{sto,in,t} - P_{sto,in}\ max) \leq 0\ \forall t \in T\ (MW) \tag{A.6}$$

$$\sum_{sto \in STO} (P_{sto,out,t} - P_{sto,out}\ max) \leq 0\ \forall t \in T\ (MW) \tag{A.7}$$

The parameter definition of the hydrogen storage system is composed of different components and is therefore explained in more detail. The parameter maximum storage charging ($P_{H2,in}\ max, in\ MW$) consists of the installed electrolyzer capacity for each scenario. The maximum hydrogen injection capacity ($P_{H2,injection}\ max,\ MW_{H2}$) is accordingly reduced by the overall efficiency of the conversion step and compression ($\eta_{H2,in}$) and results in the maximum amount of hydrogen that can be stored in the storage tank every hour.

$$P_{H2,injection}\ max = P_{H2,in}\ max\ \eta_{h2,in}\ (MW_{H2}) \tag{A.8}$$

The withdrawal capacity of the hydrogen storage facility was selected according to current data from gas storage facilities in depleted gas fields from RAG, as no data is yet available for hydrogen storage facilities [78]. The maximum injection and withdrawal capacity of natural gas storage sites of RAG Austria is currently 26.6/31.9 GW. In this relationship, referred to as injection/withdrawal factor ($f_{inj/wit}$), the hydrogen storage withdrawal capacity ($P_{H2,withdrawal}\ max,\ MW_{H2}$) has been set up. To further derive the ($P_{H2,out}\ max, in\ MW$) of the hyrogen storage system the withdrawal capacity has to be multiplied by the overall efficiency of the re-electrification process ($\eta_{H2,out}$).

$$P_{H2,withdrawal}\ max = P_{H2,injection}\ max\ f_{inj/wit}\ (MW_{H2}) \tag{A.9}$$

$$P_{H2,in}\ max = P_{H2,withdrawal}\ max\ \eta_{H2,out}\ (MW) \tag{A.10}$$

The upper limits of the energy stored in the storage capacity are restricted by the maximum energy capacity ($E_{sto}\ max, in\ MWh$) and the lower limits by the depth-of-discharge (DOD) rate (f_{DOD}), of the respective technology and considered as follows:

$$\sum_{sto \in STO} (E_{sto,t} - E_{sto}\ \max\ (1 - f_{DOD}) \leq 0\ \forall t \in T\ (MWh) \tag{A.11}$$

$$\sum_{sto \in STO} (P_{sto,out,t} 1 - E_{sto,t-1}) \leq 0\ \forall t \in T\ (MWh) \tag{A.12}$$

The non-negativity constraints for dispatchable power plant generation, storage charging and discharging, load and energy stored are given as follows:

$$\sum_{i \in I} P_{i,t} \geq 0\ \forall t \in T\ (MW) \tag{A.13}$$

$$\sum_{sto \in STO} P_{sto,t} \geq 0\ \forall t \in T\ (MW) \tag{A.14}$$

$$P_{load,t} \geq 0\ \forall t \in T\ (MW) \tag{A.15}$$

$$\sum_{sto \in STO} E_{sto,t} \geq 0\ \forall t \in T\ (MWh) \tag{A.16}$$

Battery systems are subject to the constraint that their energy stored at the begin of the regarded year ($E_{bat,init}, in\ MWh$) has to be equal to their energy stored at the end of this year ($E_{bat,fin}, in\ MWh$):

$$E_{bat,init} = E_{bat,fin}\ (MWh) \tag{A.17}$$

Since hydrogen storage facilities offer the biggest energy storage capacities and hydrogen should also be produced for use in other sectors, hydrogen storage facilities are limited to the constraint that at least the energy stored from the beginning of the year ($E_{H2,init}, in\ MWh$) must be available at the end of the year ($E_{H2,fin}, in\ MWh$). The storage facility remains open at the top in order to be able to show what quantities of hydrogen can be produced for use in other sectors with the given production capacities:

$$E_{H2,init} \leq E_{H2,fin}\ (MWh) \tag{A.18}$$

The utilized climate data restrict SH and PSH start and end filling levels.

Cross-border electricity exchanges are modeled using a virtual storage capacity. They are limited by means of an overall import and export (transport) possibility ($E_{trans}, in\ MWh$) in addition to the respective maximum import and export power capacities:

$$E_{trans,t} - E_{trans,t-1} - P_{exp,t} 1 + P_{imp,t} 1 = 0\ \forall t \in T\ (MWh) \tag{A.19}$$

$$E_{trans,init} = E_{trans,fin}\ (MWh) \tag{A.20}$$

$$P_{exp,t} - P_{exp}\ max \leq 0\ \forall t \in T\ (MW) \tag{A.21}$$

$$P_{imp,t} - P_{imp}\ max \leq 0\ \forall t \in T\ (MW) \tag{A.22}$$

The overall import and export (transport) possibility is limited at the upper end and corresponds to the conservative assumption of full export or import with the respective import/export capacity over a period of 7 days.

Since the model does not consider regional specifics of the grid, a restriction was implemented that automatically curtails a share of the generation $\left(f_{grid}\right)$ in the event of very high fluctuating feed-in from renewable generation. This is intended to take potential grid overload into account.

$$P_{curt,grid,t} = \begin{cases} P_{RE,t}\, f_{grid} & \text{if } P_{RE,t} \geq P_{RE}\ max\left(1 - f_{grid}\right) \\ O & \text{if } P_{RE,t} < P_{RE}\ max\left(1 - f_{grid}\right) \end{cases} \forall t \in T\ (\mathrm{MW}) \tag{A.23}$$

Overall curtailment (P_{curt} , *in MW*) is restricted to the power of renewable generation in each hour.

$$P_{curt,t} - P_{RE,t} \leq 0\ \forall t \in T\ (\mathrm{MW}) \tag{A.24}$$

Residual load (P_{RSL},*in MW*) in this paper is defined by subtracting all renewable must-feed generators (run-river hydro, wind and PV) from the load (electricity demand of the public grid) for each timestep:

$$P_{RSL,t} = P_{load,t} - P_{RE,t}\ \forall t \in T\ (\mathrm{MW}) \tag{A.25}$$

B Nomenclature

See Table 4.

Table 4
Nomenclature (if not otherwise specified then MW_{el} and MWh_{el})

	Units	Description
Sets:		
$i \in I$	Fossil, waste, biomas, biomethane	Dispatchable power plants
$sto \in STO$	PSH, SH, battery and hydrogen storage	Storage technologies
$t \in T$	Hours	Time
Parameters:		
c	€/MWh	Variable costs
c_{CO2}	€/MWh	CO_2 costs
c_{fuel}	€/MWh	Fuel costs
$c_{O\&M}$	€/MWh	Operation and maintenance costs
$E_{bat,fin}$	MWh	Final energy stored in the battery
$E_{bat,init}$	MWh	Initial energy stored in the battery
$E_{H2,init}$	MWh	Initial energy stored in the hydrogen storage
$E_{inflow,t}$	MWh	Hourly natural water inflow into the hydro reservoir
$E_{sto}\ max$	MWh	Maximum energy capacity of the storage unit
$E_{trans,fin}$	MWh	Final virtual import export storage capacity
$E_{trans,init}$	MWh	Initial virtual import export storage capacity
f_{DoD}	Between 0 and 1	Depth-of-discharge (DOD) rate
f_{grid}	Between 0 and 1	Curtailment factor due to grid congestion
$f_{inj/wit}$	Between 0 and 1	Injection to withdawl factor
$f_{PV,t}$	Between 0 and 1	Hourly historical power factor of PV dependent on the climatic conditions of the chosen year
$f_{wind,t}$	Between 0 and 1	Hourly historical power factor of wind dependent on the climatic conditions of the chosen year
$P_{EV,t}$	MW	Hourly load of EVs
$P_{exp}\ max$	MW	Maximum export power
$P_{H2,injection}\ max$	MW_{H2}	Maximum hydrogen injection capacity
$P_{H2,withdrawal}\ max$	MW_{H2}	Hydrogen storage withdrawal capacity
$P_{HP,t}$	MW	Hourly load of HPs
$P_i\ max$	MW	Installed capacity of dispatchable generation
$P_{imp}\ max$	MW	Maximum import power
$P_{load,t}$	MW	Hourly load/demand dependent on the chosen year
$P_{other,t}$	MW	Hourly load of historical load
P_{PV} max	MW	Installed capacity of PV generation
$P_{PV,t}$	MW	Hourly generation power of PV
$P_{RE}\ max$	MW	Installed capacity of renewable generation
$P_{RE,t}$	MW	Hourly generation power of renewable electricity
$P_{river,t}$	MW	Hourly generation power of run-of-river hydroelectricity
$P_{RSL,t}$	MW	Hourly residual load
$P_{sto,in}\ max$	MW	Maximum storage charging power
$P_{sto,out}\ max$	MW	Maximum storage discharging power
P_{wind} max	MW	Installed capacity of wind generation
$P_{wind,t}$	MW	Hourly generation power of wind
$\eta_{sto,in}$	Between 0 and 1	Efficiency of storage charging
$\eta_{sto,out}$	Between 0 and 1	Efficiency of storage discharging
Variables:		
$E_{sto,H2,fin}$	MWh	Final energy stored in the hydrogen storage
$E_{sto,t}$	MWh	Hourly energy stored in storage technology
$E_{trans,t}$	MWh	Hourly energy exported (modeled as virtual storage plant)
$P_{curt,grid,t}$	MW	Hourly power of curtailment due to grid congestion

(*continued on next page*)

Table 4 (*continued*)

	Units	Description
$P_{curt,t}$	MW	Hourly power of curtailment
$P_{exp,t}$	MW	Hourly power of exports
$P_{i,t}$	MW	Hourly power by dispatchable power plants
$P_{imp,t}$	MW	Hourly power of imports
$P_{sto,in,t}$	MW	Hourly power consumption of storage technologies charging
$P_{sto,out,t}$	MW	Hourly power output of storage technologies discharging

C Variable costs and efficiency

Table 5
Variable costs and efficiency of included power plants and storage technologies

	Variable costs		Efficiency	Source
	(€/MWh$_{th}$)	(€/MWh$_{el}$)		
CCGT Fossil	45.04/65.64		0.60	[79–81] Net Zero Emissions by 2050 Scenario
OCGT efficient			0.41	
OCGT inefficient			0.31	
Biomethane plant	41.00		0.4	[82]
Biomass plant	31.73		0.39/0.4	[83,84]
Waste	5.99		0.34	[83] and own assumption
PSH		0.95	0.79	[61,84]
Lithium-ion battery		1.09	0.90	[60,84]
Hydrogen storage		2.02	0.37/0.46	[60,62,63,85]

D Details on the scenario outline and assumptions

This section describes the assumptions underlying the model-based analysis. Sections D.1-3 each present the respective scenario.

D.1 Policy scenario (A)

The *policy* scenario specifically incorporates existing policy objectives, encompassing the targets outlined in the EAG and the Integrated National Energy and Climate Plan for Austria [86]. The specific parameters included in the model for the respective scenario are outlined in Table 6.

Table 6
Scenario data policy

Parameter	Unit	2030	2050	Source
Electricity demand:[2]r				
Total load/demand incl. grid losses (excluding storage consumption)[3]	TWh	73	83	[13,55,87]
Of which: HPs	TWh	3.5	9	[46,51]
Of which: EVs	TWh	1.8	6	[46,53,58]
Electricity generation capacities:				
Run-of-river hydroelectricity	MW	6100	7000	[1,50]
Wind	MW	7000	12000	[1,13,88]
PV	MW	12000	22000	[1,50,56]
Biomass	MW	650	1000	[1,56]
Waste	MW	100	500	[13,58]
CCGT Fossil	MW	3000	0	[50]
CCGT Biomethane	MW	500	1000	Assumption
Storage:				
PSH capacity (turbining/pumping)	MW	5000/4300	6043/5206	[50,58]
SH capacity	MW	2489	2489	[50]
Storage charge/discharge capacity grid-scale battery	MW	534	3000	[57]
Storage in/out capacity hydrogen	MW	1000/440	5000/2200	[54,78]
Other:				
Import/export capacities	MW	2500	2500	APG assumption

[2] Average values, depending on weather year.
[3] Only load that is required from the electricity grid is considered (excluding consumption of companies covered by their own plants when not included into the public grid and households demand covered by PV and batteries).

In the context of the *policy* scenario, electricity demand (from the public grid) is expected to increase to 73 TWh by 2030 and 83 TWh by 2050. This growth is predominantly due to the ongoing shift from fossil energy sources to EVs and HPs (electric boilers are included in the overall load profile). In this scenario, EVs are anticipated to contribute 1.8 TWh and 6 TWh to electricity consumption in 2030 and 2050, respectively, while HPs are projected to contribute 3.5 TWh and 9 TWh in the corresponding years. By 2030, approximately 650000 HPs are envisioned to be deployed in Austria, according to the findings of [46]. The detailed HP input data according to categories for heating and cooling in this scenario is provided in Table 7.

Table 7
Detailed *HP input data* [51][4]

HP categories	Energy (GWh_{th}/a)	Energy (GWh_{el}/a)	Max. Output (MW_{th})	Max. Output (MW_{el})	SCOP
2030:					
Heating - air-to-air HPs	95.90	36.60	43.90	27.20	2.62
Heating - air-to-water HPs	3751.40	1311.60	1714.50	1051.60	2.86
Heating - geothermal HPs	3592.20	888.60	1641.20	338.80	4.04
Hybrid HPs	1250.50	430.20	571.50	165.60	2.91
Air-Conditioning - air-to-air HPs	8.50	2.30	14.40	4.40	3.65
Air-Conditioning - air-to-water HPs	493.90	132.10	838.00	225.90	3.74
Air-Conditioning - geothermal HPs	337.60	63.90	572.90	86.10	5.28
Sanitary Water - air-to-water HPs	764.90	253.40	165.60	66.00	3.02
Sanitary Water - geothermal HPs	235.80	80.00	51.00	17.30	2.95
Industry	1696.50	339.30	193.70	38.70	5.00
2050:					
Heating - air-to-air HPs	315.30	107.70	157.10	93.30	2.93
Heating - air-to-water HPs	10073.60	3182.60	5017.20	2973.60	3.17
Heating - geothermal HPs	2371.60	518.20	1181.60	213.10	4.58
Hybrid HPs	3357.80	1039.70	1672.40	429.80	3.23
Air-Conditioning - air-to-air HPs	37.10	9.40	63.00	18.00	3.93
Air-Conditioning - air-to-water HPs	1753.60	438.50	2975.60	749.60	4.00
Air-Conditioning - geothermal HPs	302.80	54.10	513.70	72.90	5.59
Sanitary Water - air-to-water HPs	2350.00	735.90	508.60	202.40	3.19
Sanitary Water - geothermal HPs	294.50	93.00	63.70	20.10	3.17
Industry	12285.00	2457.00	1402.40	280.50	5.00

[4] For the weather year 2015.

As of the end of November 2023, Austria has a cumulative total of 152,122 exclusively electric-powered passenger cars, representing 2.9 % of the total national passenger car fleet [89]. Future projections within this scenario assume that the EV stock in Austria will comprise around 1 million by 2030 [46] and 3 million by 2050. The profiles are divided into user type private and business. For private usage, it is assumed that the average effective usage is 36.25 km/EV/day for weekdays and 26.77 km/EV/day for weekends, with an average energy consumption of 15.75 kWh/100 km. In the car stock for primarily business usage, it is assumed that the average effective usage is 53 km/EV/day for weekdays and 21.07 km/EV/day for weekends, with an average energy consumption of 16.72 kWh/100 km. It is assumed that fast charging can be applied to approximately 80 % of the car stock. Beyond meeting heating and mobility needs, additional electricity consumption arises from the ongoing decarbonization efforts in various industries. Additionally, Austria has observed a consistent upward trajectory in total gross electricity consumption across all sectors since 2005, with exceptions during the crises of 2009 and 2020 [88]. This increase is mainly due to economic and population growth, which is also expected in the coming years.

The projections for increases in generation capacity align with the targets of the EAG in this scenario. Water storage capacity expansion is according to the PECD [50] and a battery storage capacity of 0.5 GW is assumed by 2030, only including large-scale batteries that can operate on the spot market as needed [57]. Self-consumption-optimized prosumer batteries are not considered in this context. Assumptions about hydrogen production capacities (electrolyzers) are in line with the Austrian national hydrogen strategy [54]. Technical details for hydrogen storage, such as injection and withdrawal capacities, align with the specifications of RAG overall natural gas storage capacities [78]. The DOD rates are 90 % for SH, PSH and batteries in line with (IRENA, 2020). This scenario employs assumptions from the APG based on TYNDP 2020 simulations for cross-border electricity exchange capacities. This includes a maximum foreign storage volume of 420 GWh, which corresponds to the assumption of a total export or import capacity of 2.5 GW over 7 days and is being implemented due to the occasional unavailability of import capacities when needed.

D.2 Renewables and electrification scenario (B)

The *renewables and electrification* scenario considers an ambitious expansion of renewable and hydrogen capacities and assumes a high degree of electrification. This anticipates a significant rise in electricity demand for space heating, cooling and electromobility. In order to achieve this, it is assumed that the acceptance of the population and local politicians with regard to renewable power plants in the immediate vicinity has improved. With this, the potential of national renewable resources is being used to their maximum. The generated electricity, coupled with electrolysis capacities, enables hydrogen production to decarbonize sectors that cannot be electrified. The scenario assumes a substantial expansion of the power grid to transport the produced electricity to consumers efficiently. To support this, emphasis is placed on regionally optimizing the distribution of renewable generators and electrolysis capacities. Further details on the specific parameters incorporated into the model for this scenario are provided in Table 8.

Table 8
Scenario data renewables and electrification

Parameter	Unit	2030	2050	Source
Electricity demand:				
Total load/demand incl. grid losses (excluding storage consumption)	TWh	79	95	Own assumption based on additional electricity demand of HP and EV
Of which: HPs	TWh	8	16	[51,58]
Of which: EVs	TWh	3	10.3	[46,53]
Electricity generation capacities:				
Run-of-river hydroelectricity	MW	6100	7000	[1,50]
Wind	MW	9000	20000	[50,55,58]
PV	MW	12000	40000	[1,50,88]
Biomass	MW	650	1000	[1,56]
Waste	MW	100	500	[13,58]
CCGT Fossil	MW	3000	0	[50]
CCGT Biomethane	MW	500	500	Assumption

(*continued on next page*)

Table 8 (*continued*)

Parameter	Unit	2030	2050	Source
Storage:				
PSH capacity (turbining/pumping)	MW	5000/ 4300	6043/ 5206	[50,58]
SH capacity	MW	2489	2489	[50]
Storage charge/discharge capacity grid-scale battery	MW	534	3000	[57]
Storage in/out capacity hydrogen	MW	2000/880	7000/ 3080	[54,58,78]
Other:				
Import/export capacities	MW	6000	6000	[46] and own assumption

In the *Renewables and electrification* scenario, there is a projected increase in electricity demand from the public grid, reaching 79 TWh by 2030 and 95 TWh by 2050. This increase is driven, in part, by the ambitious expansion of electromobility. According to the Environment Agency Austria's WAM scenario, an estimated 1.5 million EVs are anticipated by 2030 [90], resulting in a power requirement of 3 TWh. The 2030 target aligns closely with the annual growth rate observed between 2022 and 2023, rising from 110225 to 152122 units [89]. By 2050, 4.4 million vehicles are expected to be on the road, with an electricity demand of 10.3 TWh, reflecting the continued significance of motorized individual transport in this scenario [53]. This is due to the continuing urban sprawl in rural areas and fewer attractive alternatives. However, longer ranges and falling costs mean that the majority of vehicles will be electrically powered. Furthermore, the scenario anticipates a shift towards HPs for space heating and cooling, coupled with a rising demand for living space, evident in a 20 % per person rise from 2005 to 2021 [88]. Collectively, these dynamics contribute to heightened demand for electricity for HPs, expected to reach 8 TWh in 2030 and surge to 16 TWh by 2050. These factors together are leading to a higher demand for electricity for HPs.

On the generation side, the *renewables and electrification* scenario for 2030 incorporates the ENTSOE's wind capacity projections of 9 GW [50], aligned with SECURES assumptions [58]. By 2050, this capacity will be expanded to 20 GW, consistent with the AURES project's development trajectory [55]. PV capacities in 2030 remain identical to those of the *policy* scenario. However, in 2040, based on the integrated Austrian network infrastructure plan's (NIP) Transition scenario, they are augmented to reach 40 GW [88]. The capacity for biomethane CCGT stays constant throughout this scenario at 0.5 GW. In addition, a higher balancing through import and export capacities is also permitted. Electrolysis capacities are concurrently increased to enhance the system's ability to absorb available electricity and potentially distribute hydrogen to other sectors if a surplus exists. As the currently tradable border capacities of 9.1 GW (export) and 8.6 GW (import) represent a theoretical potential and cannot necessarily be called up at the same time, this scenario assumes 6 GW for both available import and export capacities [46]. All other capacities remain consistent with the *policy* scenario.

D.3 Efficiency scenario (C)

In the *efficiency* scenario, it is assumed that conventional electricity consumption decreases gradually through increased efficiency measures. The integration of efficiency measures, coupled with decreased demand in areas such as heating, mobility and other appliances, results in lower electricity demand compared to the previous scenarios, see Table 9. Implementing energy-efficient practices and conservation initiatives is forecasted to maintain consistent refurbishment rates in the building sector, thereby contributing to a diminishing energy demand within residential spaces. Assumptions underlying this scenario emphasize a proactive environmental consciousness among the population and industries, catalyzing concerted efforts toward electricity-saving initiatives. Essential measures to reduce consumption and enhance efficiency are introduced.

Table 9
Scenario data efficiency

Parameter	Unit	2030	2050	Source
Electricity demand:				
Total load/demand incl. grid losses (excluding storage consumption)	TWh	70	80	Own assumptions based on [13,65]
Of which: HPs[5]	TWh	2.7	6.2	[51,64]
Of which: EVs	TWh	1.4	5	[53,58]
Electricity generation capacities:				
Run-of-river hydroelectricity	MW	6100	7000	[1,50]
Wind	MW	7000	10000	[1]
PV	MW	12000	20000	[1]
Biomass	MW	650	1000	[1,56]
Waste	MW	100	500	[13,58]
CCGT Fossil	MW	3000	0	[50]
CCGT Biomethane	MW	500	1000	Assumption
Storage:				
PSH capacity (turbining/pumping)	MW	5000/4300	6043/5206	[50,58]
SH capacity	MW	2489	2489	[50]
Storage charge/discharge capacity grid-scale battery	MW	534	3000	[57]
Storage in/out capacity hydrogen	MW	1000/440	5000/2200	[54,78]
Other:				
Import/export capacities	MW	2500	2500	APG assumption

[5] The HP electricity demand for households is estimated to be 2349 GWh in 2030 and 3748 GWh in 2050 according to Kranzl [64]; industry demand according to the AIT load profile generator.

The total electricity demand in 2030 in this scenario is 70 TWh, resulting from significant efficiency improvements and a slower market uptake for EVs and HPs. By 2050, the electricity demand is projected to rise to 80 TWh, slightly surpassing the estimate provided in the renewable energy scenario by the Environment Agency Austria (78.7 TWh) [13,65]. Regarding HP development, the trajectory from Ref. [64] heating scenario is followed. The total electricity demand for HPs rises from 1.45 TWh in 2015 to 2.35 TWh in 2030 and 3.75 TWh in 2050 for buildings. Based on the AIT load profile generator, the corresponding industrial HP demand adds up to a total demand of 2.7 TWh in 2030 and 6.2 TWh in 2050 [51]. It is noteworthy that the overall electricity consumption for heating in the heat scenario is decreasing. This is a consequence of the phasing out of direct electric heating and the reduced heating load of buildings with HPs, primarily in newly constructed or thermally renovated existing structures. Additionally, a lower heat demand is anticipated due to expected climate change. All mentioned factors are incorporated into the overall demand within the *efficiency* scenario.

Regarding EVs, a lower market penetration (700000 units in 2030 and 2500000 in 2050) is projected within this scenario. Consequently, the electricity demand for EVs is anticipated to be only 1.4 TWh in 2030 and 5 TWh in 2050. The lower electricity demand is also attributed to enhanced efficiency, with an average energy consumption decreasing to 12 kWh/100 km compared to 15.75 kWh/100 in other scenarios. The adoption of smaller vehicles also influences this efficiency gain.

On the generation side, renewable capacities are slightly reduced compared to the preceding scenarios due to lower electricity demand. The only exception is 2030, where the same expansion assumptions as in the *policy* scenario are adopted, as the EAG goals have already been finalized. Otherwise, the assumptions remain consistent with those in the other scenarios.

E Detailed results

This section contains tables providing supplementary information to Chapter 4. Tables 10–15 display the detailed modeling results (generation and consumption) for the three analyzed weather years (weather year 2015–2017).

Table 10
Modeling results for power generation of the three scenarios and the weather year 2015 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
PV	13.91	13.91	13.91	26.79	48.70	24.35
Wind	19.07	24.52	19.07	32.92	54.87	27.44
Run-of-river hydroelectricity	28.56	28.56	28.56	32.77	32.77	32.77
Generation from PSH	8.12	6.50	8.91	11.33	16.91	9.43
Generation from SH	2.09	2.09	2.09	2.09	2.09	2.09
Generation from batteries	0.29	0.23	0.35	1.40	2.00	1.30
Biomass	2.35	2.32	2.26	0.58	0.02	0.74
Waste	0.35	0.35	0.34	0.28	0.01	0.35
Biomethane	1.65	1.67	1.55	0.00	0.00	0.00
Gas turbine	4.27	4.20	2.84	0.00	0.00	0.00
Hydrogen turbine	1.38	1.73	1.37	3.87	1.58	4.81
Import	1.19	2.09	1.31	0.97	3.48	0.51
Total	83.24	88.16	82.57	112.99	162.43	103.78

Table 11
Modeling results and initial assumptions by demand type (including charging losses) of the three scenarios and the weather year 2015 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
Demand (including HPs, EVs and grid losses)	73.05	79.02	70.11	83.20	94.93	80.38
PSH consumption	4.19	2.14	5.19	8.25	15.30	5.85
Battery consumption	0.33	0.25	0.39	1.55	2.22	1.44
Power-to-gas (Hydrogen)	3.93	4.66	4.34	18.63	38.63	15.49
Export	1.19	2.09	1.31	0.97	3.48	0.51
Curtailment	0.55	0.00	1.23	0.40	7.87	0.12
Total	83.24	88.16	82.57	112.99	162.43	103.78

Table 12
Modeling results for power generation of the three scenarios and the weather year 2016 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
PV	13.28	13.28	13.28	25.57	46.50	23.25
Wind	17.71	22.77	17.71	30.58	50.96	25.48
Run-of-river hydroelectricity	31.18	31.18	31.18	35.78	35.78	35.78
Generation from PSH	8.12	5.91	8.57	11.39	16.34	9.48
Generation from SH	2.03	2.03	2.03	2.03	2.03	2.03
Generation from batteries	0.30	0.22	0.31	1.33	2.18	1.23
Biomass	2.61	2.73	2.39	0.65	0.00	0.67
Waste	0.39	0.41	0.35	0.30	0.00	0.31
Biomethane	1.68	1.76	1.51	0.00	0.00	0.00
Gas turbine	4.14	3.97	2.81	0.00	0.00	0.00
Hydrogen turbine	1.21	1.89	1.30	3.57	1.93	4.63
Import	1.40	2.61	1.48	0.83	3.77	0.57
Total	84.05	88.76	82.92	112.03	159.49	103.43

Table 13
Modeling results and initial assumptions by demand type (including charging losses) of the three scenarios and the weather year 2016 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
Demand (including HPs, EVs and grid losses)	73.10	79.26	70.45	83.59	95.37	80.73
PSH consumption	4.36	1.57	4.93	8.49	14.74	6.08
Battery consumption	0.33	0.24	0.35	1.48	2.43	1.37
Power-to-gas (Hydrogen)	3.26	5.07	3.51	17.44	37.29	14.62
Export	1.40	2.61	1.48	0.83	3.77	0.57
Curtailment	1.60	0.00	2.21	0.21	5.89	0.06
Total	84.05	88.76	82.92	112.03	159.49	103.43

Table 14
Modeling results for power generation of the three scenarios and the weather year 2017 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
PV	13.07	13.07	13.07	25.17	45.75	22.88
Wind	21.15	27.20	21.15	36.51	60.85	30.43
Run-of-river hydroelectricity	30.28	30.28	30.28	34.74	34.74	34.74
Generation from PSH	8.78	6.72	9.17	10.23	16.55	8.52
Generation from SH	1.91	1.91	1.91	1.91	1.91	1.91
Generation from batteries	0.37	0.24	0.38	1.39	2.71	1.30
Biomass	2.05	1.84	1.78	1.22	0.68	1.24
Waste	0.31	0.28	0.26	0.61	0.33	0.62
Biomethane	1.18	1.14	1.12	1.11	0.29	1.03
Gas turbine	4.21	4.08	3.23	0.00	0.00	0.00
Hydrogen turbine	1.18	2.03	1.17	2.88	2.52	3.36
Import	1.45	2.42	1.26	1.42	3.70	1.01
Total	85.94	91.21	84.79	117.19	170.04	107.04

Table 15
Modeling results and initial assumptions by demand type (including charging losses) of the three scenarios and the weather year 2017 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
Demand (including HPs, EVs and grid losses)	73.36	79.96	70.97	84.02	96.52	81.00
PSH consumption	5.70	3.09	6.18	7.53	15.50	5.37
Battery consumption	0.41	0.27	0.42	1.55	3.01	1.44
Power-to-gas (Hydrogen)	4.13	5.46	4.32	22.29	43.01	18.11
Export	1.45	2.42	1.26	1.42	3.70	1.01
Curtailment	0.90	0.00	1.63	0.39	8.30	0.10
Total	85.94	91.21	84.79	117.19	170.04	107.04

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