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Future scenarios for 100% renewables in Greece, untapped potential of marine renewable energies

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ABSTRACT

This study examines the potential contribution of marine renewable generators in Greece, in order to achieve a 100% renewable energy system by 2050. Using PyPSA-Eur, a cost-optimization model of the European energy system, possible energy transition pathways are explored, across five-year intervals from 2030 to 2050. For each five-year target, a new cost assumption dataset is used, one that follows estimated cost reduction learning rates. This version of the model is called PyPSA-Eur-MREL, and is modified to include marine power generators, i.e. floating wind, wave, tidal and floating solar, but also high fidelity climate data, in the scale of 5.5 km^2 for wind and 4 km^2 for wave resources. Three different approaches were employed in this investigation: greenfield, generator constrained, and a high-load scenario inspired by Greece's National Energy and Climate Plan (NECP). The analysis focused on generator capacity and performance, the levels of utilization and availability of each energy carrier and the land-use impact of onshore and offshore generators. While the first two scenarios exhibit similar overall system capacities, they differ in land-use requirements, with the constrained case installing more bottom-fixed wind turbines (1.2 GW), thereby reducing land occupation. The high-load scenario introduces floating wind turbines (4.5 GW), however, the scale of onshore installations remains substantial, covering nearly one-third of Greece's total land area.

1. Introduction

With the ambition to decarbonize the electricity sector, the European Union has set an energy transition pathway to gradually install renewable and storing systems for the electrification of all its country-members. The common goal of each member to achieve a carbon neutrality by 2050, is suggested on the European Green Deal [1]. However, concerns are raised on how well every country can adapt to it and achieve its demand based goals. The key component of the Green Deal is the European Climate Law [2], which sets, among others, the long-term commitments on the installation of renewable energy generators. Given the fact that renewable generators output is highly affected by its type and the climate phenomena of each location, the ideal installation configuration and energy mix for each country will differ.

The complexity of power systems involve economic, technical, political, social, and environmental dimensions. With renewable energy technologies introducing inevitable fluctuations in their production, Energy System Modeling (ESM) tools have become essential for simulating and optimizing future energy scenarios. These tools can create valid investment plans or trajectories for sectoral or complete model scenarios, acquire information on the deployment, availability and curtailment of the energy carriers, while taking into account supply–demand relations, physical, geographical and economical constraints, expansion policies and more [3]. Energy models are typically divided into bottom-up and top-down logic, determined by whether a system is investigated from a detailed technical point of view, or a long-term economic perspective.

Bottom-up models are generally more suitable for power system analysis in the context of technology deployment assessments. They are characterized by usually high temporal resolution (sub 3 h), which reflects the performance of energy carriers on a sub-daily level, simulated in multi-nodal transmission networks, while respecting a cost-optimization objective function over a short period [4,5].

In order to obtain a more credible planning approach from the model, myopic modeling methods have been introduced, also discussed in Abuzayed et al. 2022 [6]. This approach ensures that the output of one year becomes the input of the next so that new model developments take into account the previous year information (i.e. costs, installation capacities, etc.).

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Myopic approaches can benefit from the introduction of learning curves [7] to provide another layer of granularity to the cost assumptions of the model. Therefore they can be used to examine reduction cost pathways over the years of modeling horizon. Assumptions can take into account matters such as technology innovations, technology maturity and existing energy policies and targets.

A modeling aspect not widely considered by literature, is the sensitivity of ESMs on the horizontal and vertical grid resolution of the climate datasets used for making energy calculations over a region. Spatial resolution has been analyzed mainly in the context of nodal resolution of the network topology, and the equivalent sensitivity of the models. The goal is to better represent the underlining sub-networks of each country and the region-to-region energy balance [8], obtain a better impression of the system costs and capacity factors of different topologies [9], identify grid bottlenecks and have a better evaluation of the expansion [10].

When modeling marine renewables, it could be argued that a denser gridded dataset would represent non-linearities of climate phenomena better than a coarser one, resulting into a higher level of resource assessment. For wave power, this has been investigated in Alday et al. [11], which shows a reduction of significant wave height biases from higher resolution datasets and better alignment with observed measurements. Similarly, for wind power, [12] suggests that higher resolution improves the assessment of coastal effects on floating wind performance and enables more accurate identification of high-performing wind farm sites.

2050 European scenarios suggesting zero CO_2. net-emissions, the feasibility of 100% RES (Renewable Energy Sources) based energy system is under question. Numerous studies on the problem refer to case-studies on country or island level, and not in a continental one. Those can range from multi-sectoral fully renewable energy systems that apart from traditional renewables emphasize on country specific resources like biomass for Germany [13], hydropower for Sweden [14], but also investigate the challenges of renewable energy penetration in large national grids like the United States [15]. Said et al. 2017 [16] studied a more versatile Irish energy mix, by integrating wave and tidal devices along with wind, solar and storage, to investigate the synergy of more RES units for a more reliable energy system. Long-term decarbonization scenarios of Tenerife island were analyzed in Escamilla-Fraile et al. 2025 [17], which outlined key actions to modernize, expand and transition its energy system. A study in a multi-sectoral 2030 and 2050 RES-only model of Denmark's energy system [18], deemed it capable of generating socio-economic profits, by lowering greenhouse gas emissions, creating job opportunities in new technological areas and decreasing expenses for fuels in transport and industry.

Reliability and energy security are important considerations in an all-renewable energy system, while challenges in the energy transition often stem from the influence of established energy industries which question its economic feasibility [19]. Multiple studies on the economic viability of renewable energy systems base their cost consumptions on total system costs objectives, not just levelized cost of electricity by each energy carrier, while using high-resolution spatial and temporal models, showcasing scenarios that can compete with the equivalent fossil-fuel ones.

In most studies, the dependability of negative emissions technologies, bioenergy, hydro and geothermal power is kept low [20,21] and modeling nuclear energy is mostly avoided for reasons related to public acceptance, large environmental impact in case of accidents, the relation of this energy type with weapon manufacturing, and radioactivity of its waste [22]. The main common ground of these, is the dominance of wind-solar power generators in energy modeling, while some introduce offshore Wind Turbine Generators (WTGs). Ocean energy technologies are explored separately, more in the context of power assessment of energy converters (Wave Energy Converters or WECs for wave power) over a specific water body and sea state, and not as parts of a complete energy system.

Being a lignite rich region, and with efforts to limit oil dependency, Greece historically relied on solid fuel power plants for domestic energy production. Only recently it has managed to restrict the use of those fossils (lignite phase-out) and allow RES to largely penetrate the market. With respect to 2024, Greece's energy mix comprises of approximately 24 GW of power capacity, with around half of it being onshore wind (5.1 GW) and solar (6.7 GW) installations [23]. The energy consumption in the electricity sector has a slight declining trend and revolves around 50 TWh for the last 15 years [24], 42.4% of which was covered by RES.

A challenge for the Greek Energy System (ES) is the interconnection of the islands, which so far are dependent on diesel power plants that raise electricity bills and are not always able to cover seasonal demand peaks [25]. Hybrid interconnected systems of RES-storage can meet electricity demands while preserving the environment. Currently there is an ongoing plan by the Independent Power Transmission Operator of Greece to connect all island clusters to the mainland by 2030, while the Cretan-Peloponnese connection is completed [26].

Each nation has broken down its commitments according to its needs and availability and submitted a National Energy and Climate Plan (NECP). Looking into Greece's targets [27], it is aiming for a 43% of final gross pan-sectoral consumption share by renewable energy sources (RES) by 2030, three quarters of which in the electricity sector would derive from WTGs. In terms of marine generators, 1.9 GW of both floating and bottom fixed offshore WTGs would be added into the mix, while the report overlooks the possibility of wave power installation.

Apart from that, the target includes the integration of 6.2 GW of storage systems installed until 2030, 4.3 GW of which is planned to come from batteries, and the rest would come from an increase of the national hydro dam storage capacity. Hydrogen's potential is also mentioned, but due to its high current cost, its complexity and the lack of infrastructure, will be directed mostly into heavy transportation sectors such as shipping, aviation and heavy road vehicles, as well as yet non-electrified industries.

The Greek landscape is characterized by large mountain ranges, and multiple island clusters with over 505,572 km^2 of available water area in its exclusive economic zone. The country's geographical location offers a significant opportunity to develop an energy mix that includes a substantial share of marine renewable energies. By integrating marine energy generators into the system, the reliance on onshore installations can be reduced. Onshore renewables often require extensive land use and can raise societal concerns.

Marine energy sources are typically more abundant and less variable, leading to a more stable energy supply. This enhanced stability not only improves overall energy performance but also accelerates decarbonization [28,29]. Access to farshore locations allows for the installation of larger generators capable of harnessing larger energy resources .

Marine renewable energies, however, have their limitations too. A key factor for installations is their distance from onshore electricity connection points and ports, as greater distances lead to higher CAPEX for generators [30,31]. Bathymetry is another factor considered carefully, one that largely limits the available sea region. As water depth increases, so does the length of piles, the structural integrity of the components, and mooring lines in the case of floating generators [32].

Lavidas et al. 2017 [33] used a high-resolution wave dataset and available generator power matrices, to estimate capacity factors (CF) of different WECs around the Greek seas. The findings show CF values of up to 20%, with the best performing regions being Cretan and central Aegean seas. Also in Vasileiou et al. 2017 [34], the eligibility of Greek seas for marine farms was put under the scope with the use of a multi-criteria decision making tool, taking into account practical, environmental and economical constraints. It concluded that a total of

2536 km^2 in central and south Aegean meets all relevant criteria for viable marine installations.

Focusing on Greece's energy system studies, early attempts to model the Greek energy system showcased scenarios with complete absence of renewable power [35] and strategies for emissions reduction of the Greek electricity sector [36] recommending the use of RES for a faster target achievement. Their integration in an energy system was later investigated in [37,38], where, under the Kyoto Protocol (1997) renewables, onshore at the time and mainly solar, wind and hydro, were investigated in terms of economic feasibility, power supply, and their role in oil price fluctuations. Following a similar approach, Rentizelas et al. 2012 [39] highlights that CO_2 prices play a major role on the integration of RES.

A study of possible expansion policies of an interconnected 2030 Greek energy system was presented by Kalampalikas et al. 2016 [40, 41]. This study showcases economic challenges of transitioning hybrid energy system scenarios, for which significant excess of renewable generator capacity is unavoidable for energy sufficiency. Interconnection of islands is considered crucial in Georgiou et al. 2011 [42], for meeting energy and emission reduction targets. The costs and RES penetration level of different long term strategies was studied by Ronioti et al. 2012 [43], showcasing carbon intensity reduction profiles for different growth and emission scenarios. Koltsakis et al. 2014 [44] developed a spatial long-term energy planning model, splitting Greece in four zones and capable of determining each zone's power capacity and simulating import–export balances with neighbors. A 2030 Greek electricity market hourly model in Simoglou et al. 2014 [45] found that RES can decrease marginal energy prices, but thermal units are mandatory to compensate for the intermittency of power injection. Benefits at multiple sectors of a high-share RES 2050 energy system are showcased in Tigas et al. 2015 [46], together with a breakdown of yearly investment and operational costs.

A capacity expansion bottom-up model was developed in Georgiou et al. 2016 [47], demonstrating the potential benefits of harnessing wind power resources in the Aegean Sea. The study emphasized their role in supporting interconnection efforts and contributing to mainland electricity supply during periods of high demand. Then, Simoglou et al. 2018 [48] continued the work of [45] and developed a probabilistic evaluation of the long-term resource adequacy methodology, to conclude that RES reduce the hourly flexibility of energy adequacy in the system. Lastly, Simoglou et al. 2021 [49] investigated the impact of 2050 NECP predictions of Greece on its power system expansions in the context of system loads, power supply and curtailment, resource adequacy and economic evaluation.

Most of the aforementioned studies regarding Greece emphasized into the long term planning of expansion in a country level, with onshore wind, solar and hydro dams being the main renewable sources. This study aims to present potential solutions for the Greek electricity system, derived by simulations on an detailed Greek network topology in an hourly level. For the first time marine renewables have been included (wind bottom fixed, floating, wave energy, floating solar), while their untapped potential in marine regions is highlighted.

For the 2050 horizon, floating wind emerges as a significantly more prominent technology, but has so far received little attention in Greece. The results provide alternative pathways for 100% renewable energy system that minimize spatial requirements. In addition, a survival function is introduced that seeks to underline the relationship between utilization and installed capacity, and its impacts on the re-design of the system in future runs.

2. Methods

The used model of this research is called PyPSA-Eur [50]. It is a cost optimization model of the European energy system on the transmission network level, which is derived from a constructed high-voltage network map via OpenStreetMap (OSM). Recently, the model immigrated from the traditional European Network of Transmission System Operators for Electricity (ENTSO-E) for the 2023 Ten Year Network Development Plan (TYNDP) [51] network to the OSM tool which represents the network with greater detail.

The model can provide capacity, energy and cost calculations from an hourly resolution analysis of power systems with a certain network topology, suitable for operational and expansion studies. PyPSA-Eur is based on the PyPSA (Python for Power System Analysis) [52] toolbox which aims to minimize a cost objective function. This function takes into account investment and operational costs of the utilized components, and is subject to global and component-specific constraints, with respect energy flow balances in every network bus. The objective function is shown in Eq. (1):

$$\sum_{n,s} c_{n,s}\bar{g}_{n,s} + \sum_{n,s} c_{n,s}\bar{h}_{n,s} + \sum_{l} c_l F_l + \sum_{t} w_t \left[\sum_{n,s} o_{n,s,t} g_{n,s,t} + \sum_{n,s} o_{n,s,t} h_{n,s,t} \right] \tag{1}$$

where n, s denote buses and energy carriers, $\bar{g}_{n,s}$ and $\bar{h}_{n,s}$ are the nominal capacity of generators and storage, $c_{n,s}$ is the capital cost of technology per MW, F_l is the capacity of network branch l with cost c_l; for operational costs, w_t is the time weighting of operation hours, $g_{n,s,t}$ and $h_{n,s,t}$ are dispatch values of generators and storage units at time t, and $o_{n,s,t}$ their operational costs.

For the case of Greece, the prebuilt version of TYNDP was still missing Peloponnese, Crete and island connections. The first two were able to be added manually by merging the network version of the Greek Independent Power Transmission Operator (IPTO) [53], the ENTSO-E and OSM versions. The double-cable connection between Crete and Peloponnese is rated to 150 kV, however PyPSA-Eur cannot model cable lines of lower than 200 kV. These cables in this network are set to 200 kV, increased compared with their actual voltage levels, but since future plans include a new link between Crete and Attica, this adaptation was considered to be an acceptable alternative for the present network.

Adding nodes to the island clusters did not generate different results, as confirmed by tests conducted during this study, since they are not included neither in the onshore nor the offshore territories of the land-use datasets. Their population data, which determine energy demand, are aggregated into the rest of the country.

Fig. 1 shows the map transformation with the updated area coverage by each node, while the unregistered islands are left colorless (white). Despite represented by straight lines, the lengths of all new high-voltage cables were measured with respect to their actual lengths. The final grid contains 45 buses and is set to have a possible expansion of 25% for every year-scenario.

Marine renewables such as wave energy converters (WECs), floating wind, floating solar, tidal converter are integrated into the model, these developments are implemented in Lavidas et al. 2025 [54], where the version PyPSA-Eur-MREL if further explained. New cost assumptions were adapted for all renewables and storage units that follow cost reduction pathways according to adjusted learning rates (LR). Learning rates are determined for each decade until 2050, and taking into account the European targets for each energy carrier and its current cost, the final investment costs are calculated.

Onshore wind and fixed solar remained the cheapest solution for all years, but had the smallest cost reduction due to their already high presence. Wave and floating wind power, shows a significant drop in costs, starting from more than 2000 €/MW to 900–1500 €/MW for wave, and floating wind reaching 2260 €/MW in 2050. Lastly, floating solar showed the largest cost deduction, however, it was by far the most expensive, reaching 3450 €/MW.

This model considers bottom fixed and floating turbines of 12 and 15 MW respectively. Tidal energy, while integrated, was not considered in the Greek model as the resources were insignificant compared to the rest technologies. Floating solar panels are also considered in the

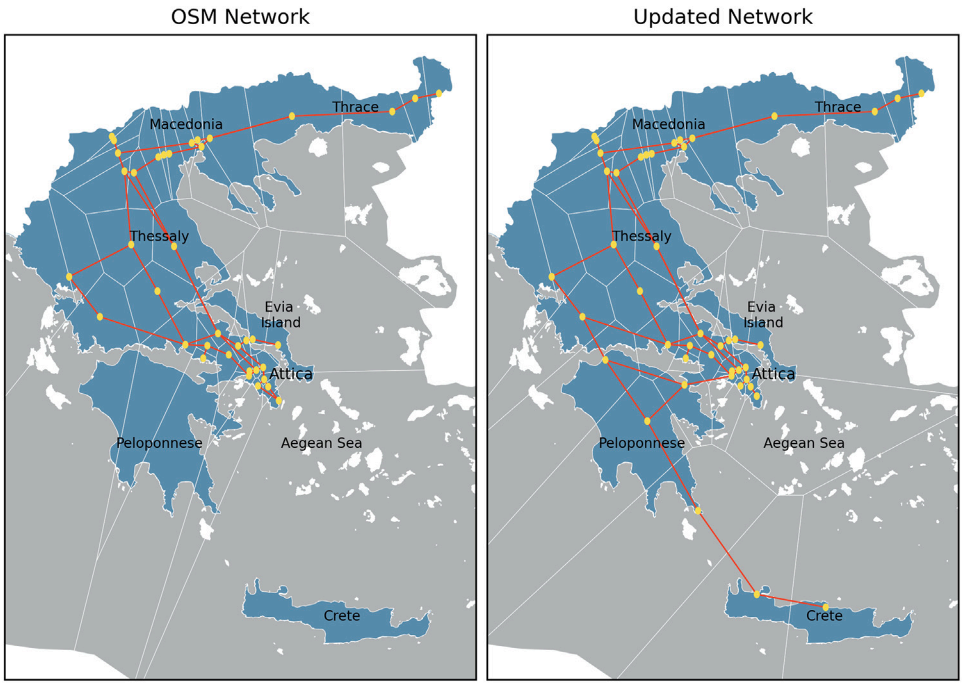


Fig. 1. Maps of the original (left) and updated (right) network configuration of Greece. Each node is assigned a polygonal catchment area (Voronoi Cell) that determines the energy demand and links power components on that node. The new network has a total of 45 nodes and 55 lines.

Table 1
Device characteristics on distance and water depth ranges, rated power and packing density. BF refers to bottom fixed WTGs and FL refer to Floating ones.

Device	Distance from shore range (km)	Water depth range (m)	Rated power (kW)	Packing density (MW/km^2)
Shallow WEC	0–10	5–20	290	30
Nearshore WEC	10–100	20–100	400	35
Farshore WEC	0–100	80–250	750	50
Onshore wind	–	–	3,000	3
BF Offshore Wind	0–10	5–60	12,000	7
FL Offshore Wind	10–50	60–250	15,000	9
Solar	–	–	–	1
Solar-HSAT	–	–	–	0.85
Floating Solar	0–100	0–100	–	1

model, with a packing density of 1 MW/km^2, which is the same as the fixed onshore panels, and maximum water depth of 150 m.

Table 1 shows all renewable device characteristics. Due to wind wake effects, the spatial footprint of offshore WTGs has to be quite large, due to their diameter, which for the 15 MW WTG is 240 m. Thus, their packing density per unit of area (MW/km^2) is less than the rated power of the device itself as the spacing of the devices exceeds 1.5 km for both bottom fixed and floating devices. WECs, however, benefit from their significantly smaller dimensions, and given the fact that wake effects are less prevalent and can be constructive, they can be placed closer together and obtain a significantly larger packing density.

Fig. 2 presents a visual image of the potential installations of generators around Greece which is standard for any scenario investigated, this should not be confused with the feasible installable values. These values are unconstrained.

Hydro energy is also taken into account in three different types. Firstly, Run-of-River (R-o-R) is considered to be a power generating component that is not extendable like the rest of RES. The reason for that is the risks that emerge by relying in changing hydrological phenomena, that due to climate change can lead to shortages, drought, and inability for operation for extended periods [55]. The same applies to the rest of hydropower energy carriers, namely Pumped up Hydro (PHS) and Hydro Dams, with the difference that they are considered as storage units in the energy system.

Distance constraints were set for the onshore generators too. Onshore facilities raise social concerns regarding their installation in close to communities, due to their size, their visual and auditory discomfort, distance thresholds in the model limit their proximity to those.

One of the improvements of PyPSA-Eur-MREL is that it supports significantly higher resolution than the existing ERA5 [56], which has a horizontal resolution of 27.5 km (0.25°) for wind resource and 55 km (0.50°) for wave. As detailed in [54], the model uses the Copernicus European Regional ReAnalysis (CERRA) dataset [57] for wind, and for wave power the European Coasts High Resolution Ocean WAVEs Hindcast (ECHOWAVE) dataset developed in [11].

CERRA is pan-European dataset with 5.5 km horizontal resolution and 106 vertical levels, derived by downscaling ERA5. While ERA5 is struggling to capture detailed wind resources near coastal waters, CERRA offers more accurate coastal assessments, those at a 3-hour resolution. To create a complete hourly level dataset, time-series of the +1st hour and +2nd hour forecasts of each timestamp were merged with the analyses timestamps to generate the one hour dataset suitable for PyPSA's analysis.

Similarly, ECHOWAVE is a 30-years hindcast 1-hour resolution dataset of the North-East Atlantic ocean [11], the validated physics

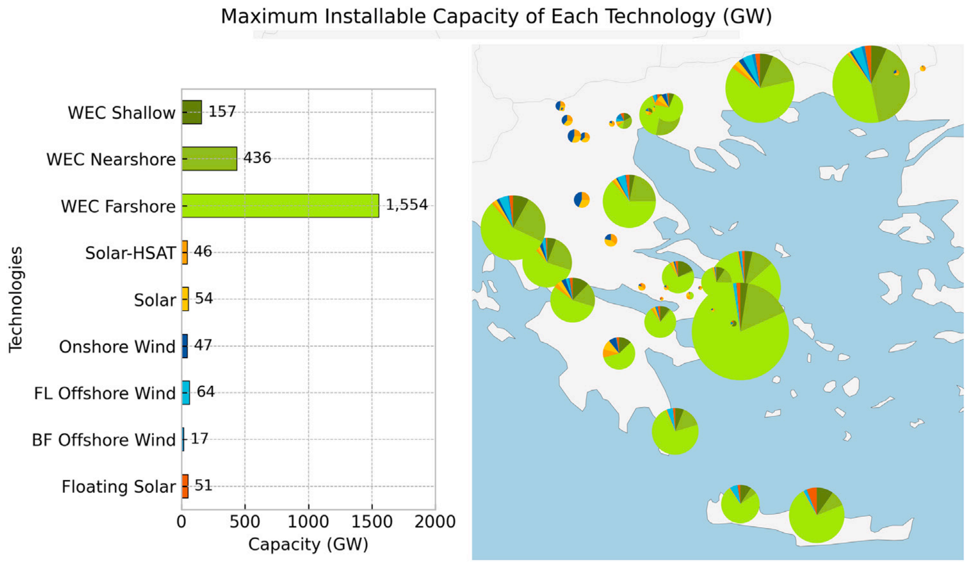


Fig. 2. Maximum installable capacity per extendable generator for Greece.

Table 2
Scenarios overview.

Scenarios	Network expansions	Timeframe	Load demand
Greenfield (GR)	Independent results for each run	2030–2050	+5% every 5 years
Generator Constrained (BAU)	Generator capacities preserved for every new run	2030–2050	+5% every 5 years
2050-NECP	Greenfield approach	2050	+160%

have been used to develop the EU ECHOWAVE including the Mediterranean Sea, Black Sea and Baltics. The dataset features a horizontal resolution of 4 km, making it especially relevant for depths below 200 m, as this is the range of interest for WEC devices deployment.

The loads have been adjusted with a linear increase of 5% every 5 years. This increase is based on EU27 electricity demand trends found in Scenario Report of TYNDP 2022 [58], where the final electricity demand projection for 2050 is between 3500 and 3800 TWh for EU27. The reference year in PyPSA-Eur-MREL is 2020 for climate and demand data, for EU27 around 2750 TWh (without UK and Norway, 3350 TWh in total). This makes a difference of +30%–40%, depending on higher or lower demand scenario.

Even though the consumption trend of Greece is horizontal for the most part of the last 15 years and the population is not expected to rise, it is assumed that industry progress will increase the electricity demand, especially with the possibility of large data center unit installations. The NECP [27] however, forecasts significantly larger loads for 2050, reaching 135 TWh/year. A separate scenario to analyze the higher load network is also performed in this study. Table 2 presents the three scenarios, and Fig. 3 provides an overview of the research framework of the current work.

3. Results

The results section is divided into three parts. The first part presents the results of a greenfield optimization of each individual year scenario, the second part refers to the generator constrained or Business-As-Usual (BAU) scenarios for the same years, and the third part refers to the NECP high-load scenario. BAU in this case is not used for the investigation of a specific policy with minimum requirements of generator capacities. It is used to restrict the greenfield solution and carry the installations of the previous years to the next, with its costs recalculated. The lifetime of the devices is considered only for calculating the annuity of their capital costs, and not for their influence in the model's selection of technology.

The energy system under investigation is analyzed with respect to the generator installations around Greece, while storage capacities are supplementary to the power mix. It is considered preferable to opt for generator based energy rather than relying on the coverage of storage, for reason related to their rare materials and their technological requirements.

3.1. Greenfield simulations

Greenfield simulations commit to a fresh run each time they start. The results for future years do not have any dependency on the previous-year, thus generator capacities do not necessarily have an increasing trend or dependency. Dispatch, withdrawal-curtailments, annual load demand growth, non-linear cost reduction pathways, and the capabilities of higher-cost storage systems all play a role in the dynamics of the model, its supply–demand balance, and final outcomes. Greenfield results for energy carrier capacities are shown in Table 3 where they are compared with their BAU equivalent (in Section 3.2, included here for space saving and clearer comparison).

All of the year-scenarios have energy mixes relying on onshore wind and solar generators and absence of floating or wave devices. Offshore WTGs are initially installed (1.2 GW), but their capacity drops as demand increases, despite the cost reductions. It is observable that from year 2040 and later, the model shifts by a lot towards solar-HSAT (Horizontal Single Axis solar Tracker), reducing both conventional solar and offshore WTG capacities. This difference is more exaggerated in 2050, where solar in total represent more than 15 GW of the energy mix and bottom fixed turbines are reduced to 684 MW.

Apart from pumped up hydro storage (PHS) and reservoirs, which are considered non-extendable carriers, new storage units all have an almost linear increasing trend. Since Greece receives ample solar energy throughout the year and has small cloud coverage. Therefore, the cheaper and lower maintenance solar and solar-HSAT generators, are coupled with hydrogen and battery storage systems. This lower cost driven solution is preferred over more wind generator units, that their

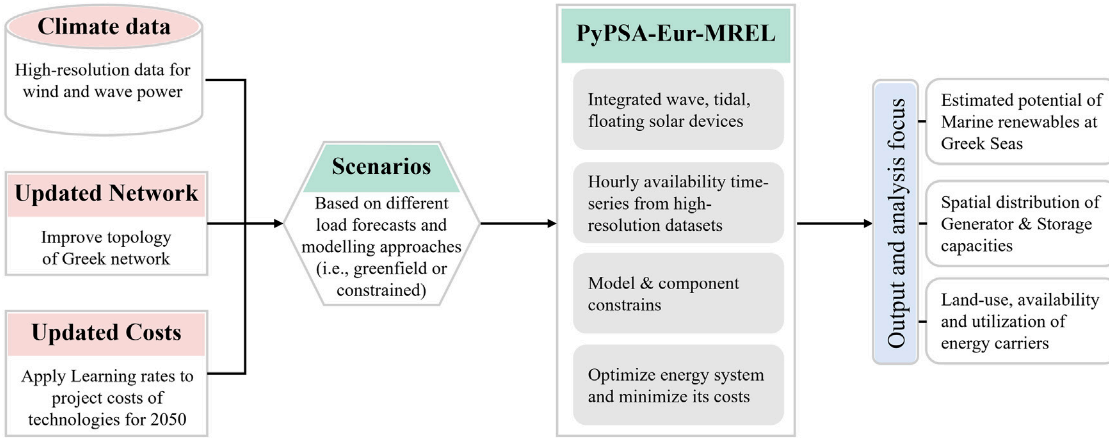


Fig. 3. Research framework of this work.

Table 3
Generator and storage capacities per scenario (GR as in Greenfield and BAU) and year together with their differences (Diff.).

Carrier	Optimal capacity (MW)													
	2030	2035			2040			2045			2050			
		GR	BAU	Diff.	GR	BAU	Diff.	GR	BAU	Diff.	GR	BAU	Diff.	
Solar	6,029	7,238	7,092	−145	5,430	7,092	1,662	5,609	7,092	1,483	5,430	7,092	1,662	
Solar-HSAT	2,544	2,401	2,544	144	6,638	4,197	−2,441	5,973	4,539	−1,434	9,883	6,178	−3,705	
Onshore Wind	13,709	13,820	13,811	−9	12,935	13,811	876	14,399	14,303	−97	12,940	14,303	1,363	
BF Offshore Wind	1,217	1,217	1,217	0	956	1,217	261	956	1,217	261	684	1,217	533	
Run of River	103	103	103	0	103	103	0	103	103	0	103	103	0	
Total Generators	23,602	24,778	24,768	−10	26,062	26,420	358	27,041	27,254	213	29,041	28,893	−148	
H2 electrolysis	850	1,209	1,198	−11	1,235	1,078	−157	1,427	1,407	−20	1,675	1,407	−269	
H2 fuel cell	6,164	6,759	6,758	−1	7,304	7,298	−6	7,808	7,807	0	8,388	8,328	−60	
Battery	2,179	2,282	2,281	−1	2,504	2,468	−37	2,632	2,617	−16	2,857	2,768	−88	
PHS	699	699	699	0	699	699	0	699	699	0	699	699	0	
Reservoir & Dam	2,566	2,566	2,566	0	2,566	2,566	0	2,566	2,566	0	2,566	2,566	0	
Total Storage	12,458	13,514	13,501	−13	14,308	14,109	−199	15,132	15,096	−36	16,185	15,768	−417	

production is less guaranteed and potentially would have their energy curtailed.

All of the networks from 2030 to 2050 have no cable expansion. Fig. 4 shows the potential locations of installations from 2030 to 2050-greenfield scenarios. Bottom fixed WTGs are installed mostly between the area of Attica, Evia and Crete for 2030, but for 2050, some of those regions replace their WTGs with solar-HSAT. Based on carrier packing density, areas occupied by each one have been calculated. In total for 2050 onshore generators would cover 21,370 km^2, an area which is as large as the entire Peloponnese area, and is 57% greater than the coverage of 2030 capacities. The spatial configuration of storage units is mostly the same among the scenarios, with the only noticeable difference being, apart from the overall increase of capacities, the increase of batteries in West Greece for 2050.

Fig. 5 shows an average week of power output calculated from the total year of system operation. Seasonal variations in climate patterns are not reflected here, as they have been averaged into the overall system performance. The load demand (magenta line) is constantly covered with the help from dispatch of stored energy from batteries, hydrogen, PHS and hydro dams. The energy system operates on average, at 25.8% (7.5 GW) of its installed generator capacity, which is 3% higher than the system's average demand of 7.3 GW. On the best-performing day, 57% of the generator capacity was utilized, whereas, on the worst-performing day, the contribution of the generators dropped to almost zero, during nighttime. This variability underscores the necessity for a substantial amount of storage units in the system, which is greater than the highest load recorded (12.3 GW).

Over the course of year 2050, renewable generators alone were able to meet the load for more than 65% of the time-steps, while being below the minimum recorded load for 16% of the time-steps. The system was powered almost exclusively by storage units (there is always at least a small contribution from generators) for 3% of the time, and in total those surpassed the production of generators for 14.5% of the time.

The percentages above refer to 2050, but considering each individual year-scenario as a higher-load scenario applied to the same climate dataset of year 2020, the year-to-year results, generally indicate that adding more generators does not lead in meeting demand more frequently. In fact, it results in more instances where storage power surpasses generator power. This shows the limitations of a fully renewable system, as the climate phenomena are the ones to restrict the production and not the power capacity alone, or the impact of having single weather year to design a future energy system.

Another limitation of an energy system is the curtailment of energy. Curtailment in the present models is the product of excess of energy that remains available but unused after powering the network and charging the storage units.

Typically the highest amount of system curtailment can be found during the noon of each day, where the solar generators have their maximum output. Details of each year scenario on capacity and energy metrics can be found in Table 4. It is evident that curtailment has a total decrease of 17% over the years, except in 2045, while the use of storage units increases significantly. By 2050, there is a proportional relationship between the growth of generator capacity and energy supply, but storage units supply rises by 60% despite a capacity growth of 30% compared to 2030, effectively utilizing excess energy and dispatching it more frequently than in previous years.

Each year scenario has its total system cost calculated from scratch. This includes investment, maintenance and variable costs that source

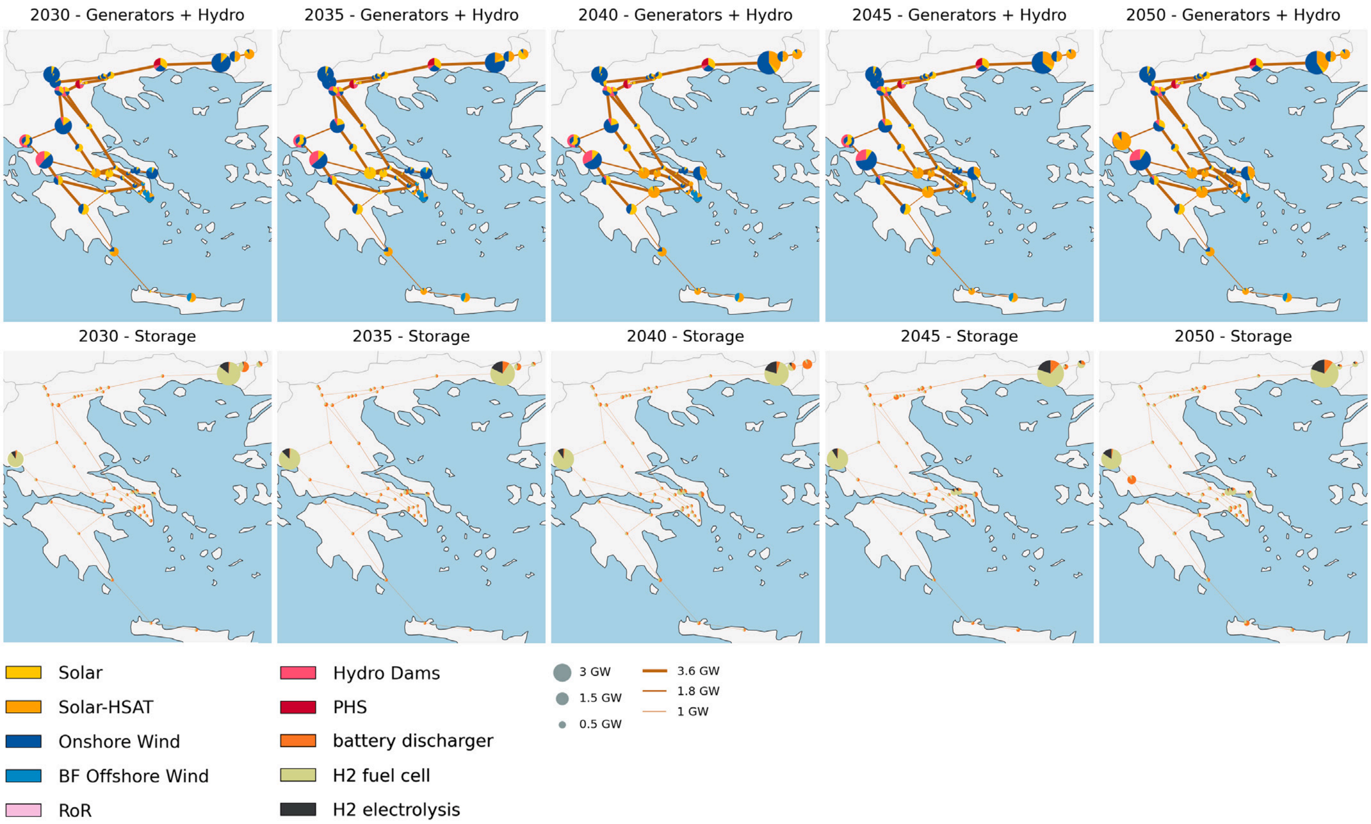


Fig. 4. Energy system of years 2030 to 2050.

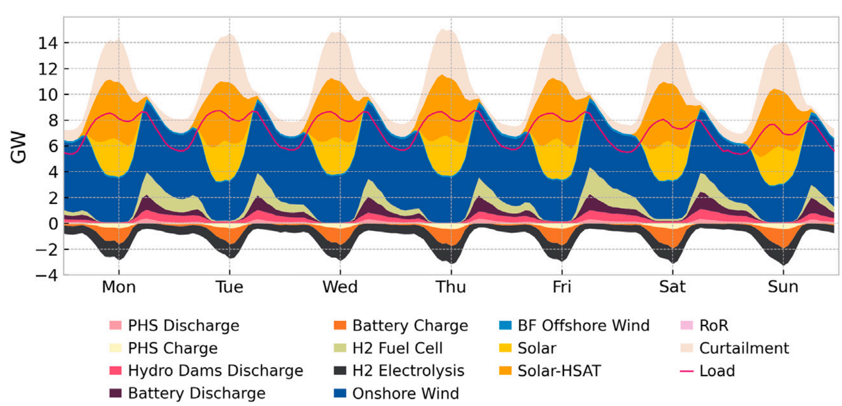


Fig. 5. Average week performance of 2050 scenario, including all of the components of the network.

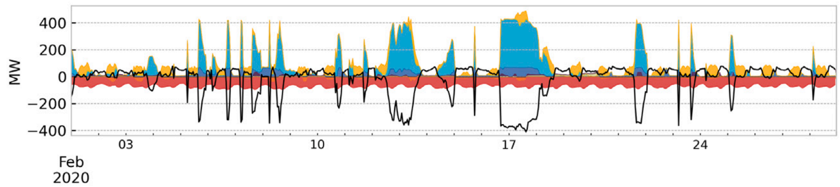
Table 4
Summarizing table of each year scenario of Greenfield simulation including capacities of components and energy-specific details.

Year	Capacity generators (GW)	Capacity storage (GW)	Supply generators (GWh)	Supply storage (GWh)	Curtail-ment (GWh)	Storage withdrawal (GWh)	Cable loses (GWh)	Load (GWh)
2030	23.6	14.6	54,195	10,760	17,530	11,048	77	53,830
2035	24.8	15.7	57,340	12,162	16,267	13,171	55	56,277
2040	26.1	16.8	60,062	14,084	15,032	15,322	100	58,723
2045	27.0	17.7	62,702	14,416	16,494	15,849	98	61,170
2050	29.0	19.0	65,784	17,577	14,552	19,664	81	63,617

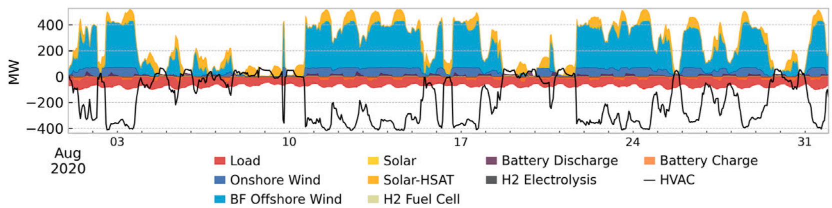
from building and operating the network for a full year. For greenfield scenarios this cost ranges from 6 billion € for year 2030 to 5.1 billion € for 2050, with a progressively decreasing cost trend for the years in between. However, this means that for the costs of 2050 for example, an amount of generators and storage units would have been previously installed under higher costs.

A more detailed time-series is shown in Fig. 6 where it presents a coastal bus of the Athenian region in February and August of 2050 which includes bottom fixed WTGs (407 MW). Here the load is shown in the negative y-axis.

High Voltage Alternating Current (HVAC) lines provide energy to neighboring buses whenever there is a high level of generator power.



((a)) Time-series of bus in February.



((b)) Time-series of bus in August.

Fig. 6. Time-series of a bus in coastal AtticaAthens, for 2050 scenario, which includes bottom fixed WTGs for the months of February (a) and August (b).

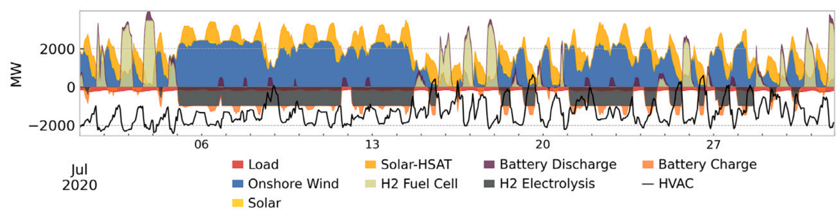


Fig. 7. Time-series of a bus in Thrace for 2050,with large capacity of H_2 electrolyzers and fuel cells.

This is also observed by the mirror shapes (with respect to the x-axis) between offshore wind (positive) and HVAC (negative) power output. However, there are instances where HVAC lines are positive, which means that energy needs to be imported to the bus and meet the demand. These two months are considered representative for a *suboptimal* and an *optimal* performance of the generators, showcasing the balance of power in the bus in any case. Since this bus has a low demand (less than 100 MW per hour), electricity is mostly exported to neighboring buses whenever the turbines are operating.

Fig. 7 shows the balance of power in a bus in Thrace for the month of July, which includes a large amount of H_2 electrolyzers and fuel cells. The electrolyzers here take advantage of the low load, and the existence of continuous wind power output, whenever is present, to store hydrogen for long periods (even for a full week), and then dispatch this energy with fuel cells mainly during nighttime for shorter periods.

3.2. Generator constrained (BAU) simulations

Most of the comparisons of BAU results refer to the differences between the 2050 scenario with its greenfield equivalent. The first year (2030) is the common starting point for each scenario, and the load scaling is kept the same for each year. The results are quite similar to those from greenfield simulations, and are included in Table 3 in Section 3.1.

From year 2035 to 2050, the capacities of solar and offshore WTGs are at ≈ 7.1 and 1.2 GW respectively, while onshore turbines and solar-HSAT increase. The 2050-BAU network seems to satisfy demand with marginally less power overall, compared to the equivalent greenfield scenario. Installed capacity of generators is the same (a difference of ≈-148 MW) and storage units are reduced by 417 MW (≈ 330 MW of H_2 and 90 MW of batteries).

In monetary terms, this network costs around 74 million € more, increased by 1.4%, due to the fact that the per MW cost of offshore WTGs is substantially larger than the rest of the generators, in this case the solar panels and onshore wind turbines.

Possibly the largest benefit of these scenarios is the reduced requirement of land for installations. The 2050 BAU scenario uses 2243 km^2 less land for onshore generators, trading it with only 76 km^2 of offshore WTGs at the sea, as can be seen in Table 5 which shows the large differences of land-use per generator. These differences are also influenced from the minimum generator capacity constraint, that set simple solar panels at 7.1 GW, which, combined with the higher packing density of offshore WTGs, prevents the installation of more space-demanding HSAT panels.

Table 6 summarizes power and energy metrics of the BAU networks for generators and storage units. The 2050-BAU scenario has 18% more curtailment of energy, which is expected as these types of runs have minor total capacity differences compared to greenfield. The increase in curtailment is closely matched by a reduction in storage withdrawal (≈ 2.7 GWh), indicating a shift in energy distribution and a slightly reduced dependability to storage. Overall, the share of storage in total energy supply reduces by 1.9%.

3.3. High load scenario

Even though Greece's load trend is approximately constant for at least the last 15 years, the NECP report predicts dramatically larger generator capacities for 2050 and total electricity supply. Specifically, generator power is to be increased by ≈ 200% and the demand by ≈ 160%. This NECP load scenario was also included in the analysis and its results show a network two to three times more expensive than any other Greenfield or BAU scenario (≈ 15 billion €), a number aligned with the demand increase factor.

Table 7 breaks down specific aggregated per generator type details of this network. Compared with NECP predictions, the capacity of generators reaches 57.5 GW, 13 GW less than NECP.

New storage systems reaching significantly higher capacities. Specifically, 21.4 GW of H_2 fuel cells (there is no H_2 plan for the electricity sector for Greece in NECP), supplied with hydrogen by 5.4 GW of electrolyzers, along with 6 GW of batteries (12 GW in NECP).

Table 5
Generator and storage land-use per scenario (GR as in Greenfield and BAU) and year together with their differences (Diff.).

Carrier	Area (km^2)												
	2030	2035			2040			2045			2050		
		GR	BAU	Diff.	GR	BAU	Diff.	GR	BAU	Diff.	GR	BAU	Diff.
Solar	6,029	7,237	7,092	−145	5,430	7,092	1,662	5,609	7,092	1,483	5,430	7,092	1,662
Solar-HSAT	2,992	2,823	2,992	169	7,807	4,936	−2,871	7,026	5,339	−1,687	11,626	7,266	−4,360
Onshore Wind	4,569	4,606	4,603	−3	4,311	4,603	292	4,799	4,767	−32	4,313	4,767	454
BF Offshore Wind	173	173	173	0	136	173	37	136	173	37	97	173	76
Onshore Total	13,590	14,667	14,688	21	17,548	16,631	−917	17,434	17,198	−236	21,369	19,126	−2,243
Offshore Total	173	173	173	0	136	173	37	136	173	37	97	173	76

Table 6
Summarizing table of each year scenario of BAU simulation including capacities of components and energy-specific details of each network.

Year	Capacity generators (GW)	Capacity storage (GW)	Supply generators (GWh)	Supply storage (GWh)	Curtail-ment (GWh)	Storage withdrawal (GWh)	Cable loses (GWh)	Load (GWh)
2030	23.6	14.6	54,195	10,760	17,530	11,048	−77	53,830
2035	24.8	15.7	57,303	12,116	16,309	13,100	−42	56,277
2040	26.4	16.5	59,729	13,119	17,238	14,040	−85	58,723
2045	27.3	17.7	62,637	14,283	16,721	15,680	−69	61,170
2050	28.9	18.5	65,158	15,499	17,204	16,961	−79	63,617

Table 7
2050 NECP network aggregated power, area and energy values per generator, summed up for onshore and offshore categories. Mean power shows the average level of utilization of each generator type throughout the whole year of operation.

Carrier	Capacity (MW)	Mean power (MW)	Produced (TWh)	Curtailed (TWh)	Area (km^2)
Solar	6,219	933	8.2	1.2	6,219
Solar-HSAT	21,004	4,350	38.0	2.1	24,709
Onshore Wind	24,422	8,945	78.1	13.3	8,140
BF Offshore Wind	1,217	274	2.4	2.5	174
FL Offshore Wind	4,516	1,237	10.8	9.3	502
Onshore Total	51,645	14,228	124	17	39,068
Offshore Total	5,733	1,511	13	12	676

On the contrary, NECP predicts the increase of Pumped Hydro Storage (PHS) units from 0.7 to 5.4 GW, while in the present models, PHS is a non-extendable energy carrier. Storage units account for more than 42% (42.1 GW) of the total energy carrier capacity, raising concerns about the feasibility of this energy mix. Even though the energy supply from generators and storage units is more than double compared to the one in 2050-greenfield scenario, curtailment is proportionally less.

Fig. 8 shows the spatial distribution of each generator and storage type. Both floating and bottom fixed generators are located in central Aegean and Crete, while the rest of the country is power mostly by onshore and solar-HSAT generators. The large amount of H_2 fuel cells and the rest of the storage units are here distributed across the whole country with a relative proportionality to the generator capacities for most of the buses. Now, almost every bus of the network has H_2 and battery systems attached, for a cumulative energy storage potential of up to 1236 GWh.

Fig. 9 shows an average week of operation of that system, which now includes the 4.5 GW of floating offshore WTGs. On average, those operated at 1.2 GW throughout the year, and reached 8.5% of total energy production. The same behavior is observed with 2050-greenfield scenario, where storage units dispatch their energy as the sun is setting in the afternoon hours.

It is interesting that this high-load high-capacity network manages to have more instances where the generators and storage systems both surpassed demand (67% and 6.8% of the time respectively). Compared to the greenfield scenarios, where this relation was inversely proportional, i.e. as load was growing, only storage units surpassed the demand more often. However, the times where storage unit power was above generator power were reduced slightly to 14.3% of the time-steps (14.5% for 2050-greenfield).

Fig. 10 shows the region of Athens to be similar as in the greenfield scenario (Fig. 6) for the same months. Here a similar mirror pattern between the generators and the HVAC is observed, this time with significantly larger amount of power output.

This region occupies 419 km^2 of sea area for bottom fixed and floating WTGs, and by adding the remaining capacities of the country this number reaches 676 km^2. Land-use details per generator can be found in Table 7. Onshore installations use 83% more land than the 2050-greenfield scenario, reaching 39,068 km^2, an area that is approximately 30% of the total Greek land, that is excluding inland exclusion zones and restricted areas.

Fig. 11 represents the level of utilization of generators and storage units with respect to a percentage of the time-steps (availability) for greenfield and 2050-NECP scenarios. In other words this is a survival function of generator and storage capacity, for a actual-value (left) and an normalized (right) of power on the x-axis. It is noticeable that the generator and storage profiles of each scenario are analogous with their equivalent demand.

Looking at the right picture which refers to the normalized graph, generators of NECP scenario seem to obtain greater availability for any level of utilization. Storage units on the other hand, have a less clear pattern as there are levels of utilization where 2050-greenfield surpasses the NECP.

From these graphs it can be observed that a level of utilization of over 50% for both generators and storage units takes place for only 2%–3% of the time. This implies that often over-installing of energy carriers happens across multiple buses. This ensures that the demand will be met in an annual weather scenario.

With respect to NECP in Fig. 12, the level of utilization of the energy providing carriers is shown, in a normalized and a non-normalized x-axis, similarly to the previous figure. Onshore WTGs, are installed in

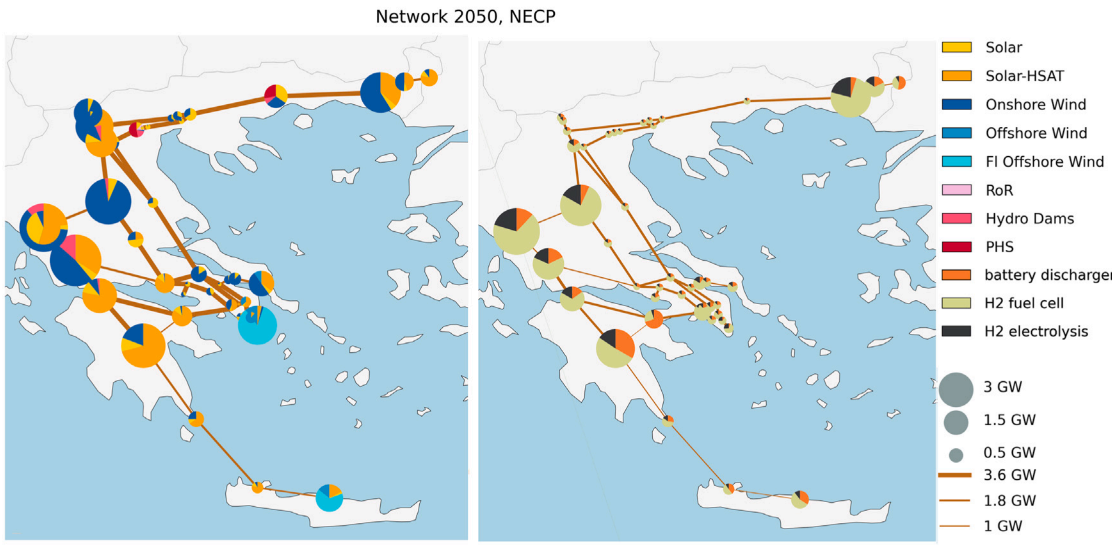


Fig. 8. 2050 generator (left) and storage (right) spatial configuration based on the higher NECP predicted load.

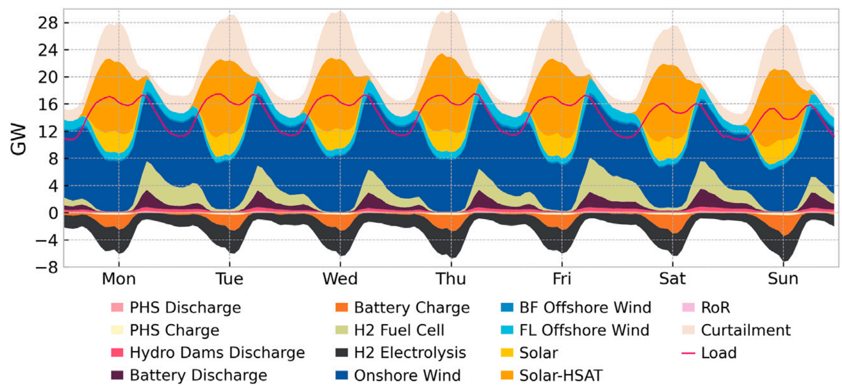
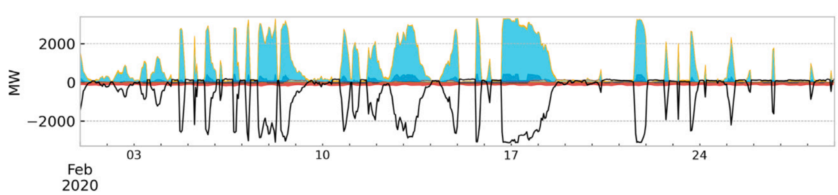
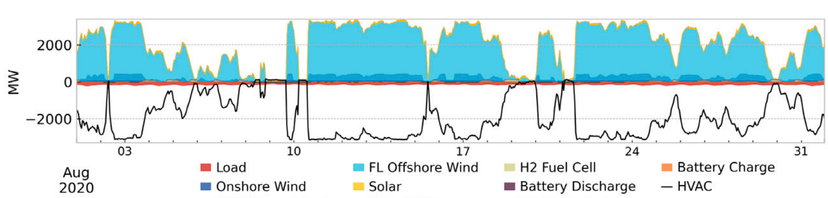


Fig. 9. Average week of performance of all components for the NECP scenario, where load is included.



((a)) Time-series of bus in February.



((b)) Time-series of bus in August.

Fig. 10. Time-series of a bus in coastal Athens, for 2050 NECP scenario, which includes bottom fixed and floating WTGs for the months of February (figure (a)) and August (figure (b)).

almost every region, and have the highest utilization, achieving 80% availability at ≈ 4 GW. It has to be noted that the benefits of HSAT over the fixed panels are clear as the first ones show greater availability constantly over any level of power output.

Interestingly, floating and bottom fixed WTGs achieve greater availability than onshore WTGs for higher levels of utilization (55% and 68% respectively). However, because they are prioritized in the case of curtailment, their contribution almost immediately (for utilization ≤ 2%) drops to 70%. Floating WTGs seem to perform better than bottom fixed ones, reaching greater availability for almost all levels of utilization. Regarding storage units, batteries achieve at maximum an availability of 35%, the largest of any type, and the 21.4 GW of H_2

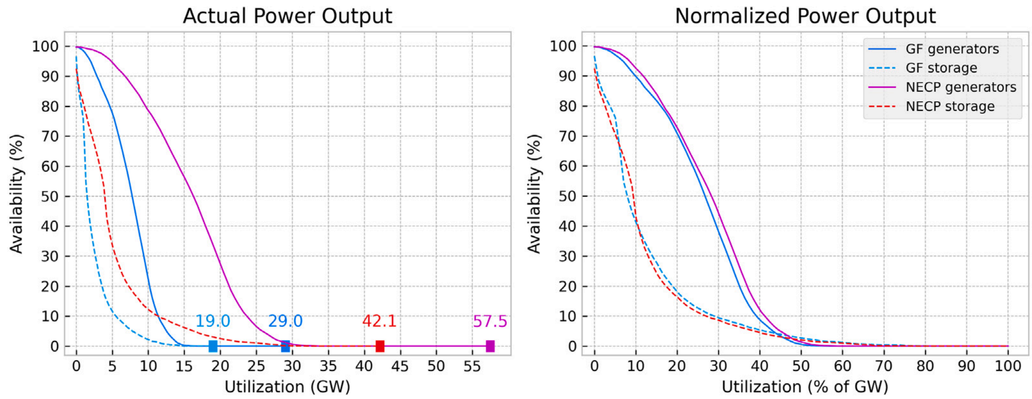


Fig. 11. Survival function of power output for aggregated generator and storage units for 2050-greenfield and NECP scenarios. Right figure represents the function with a normalized *x*-axis for all generators (% of GW), and left figure shows their actual power output for the corresponding amount (%) of time-steps (availability).

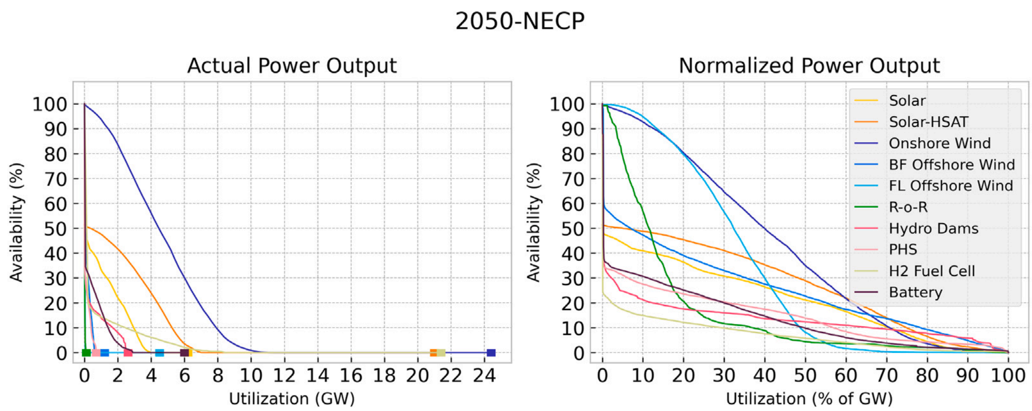


Fig. 12. Survival function of power output for generators and storage units for 2050 NECP scenario. Right figure represents the function with a normalized *x*-axis for all generators (% of GW), and left figure shows their actual power output for the corresponding amount (%) of time-steps (availability).

fuel cells reach only 25%. Both of these profiles follow a smooth curve of distribution for the levels of utilization, while hydro related storage appears to be more irregular.

4. Discussion

This study investigated the potential role of marine renewable energies in the Greek energy system with respect to a 2050 horizon, using ultra high resolution wind and wave climate datasets with 5.5 km and 4 km spatial resolution at 1 h for wind and wave resources. Low electricity load scenarios, namely the greenfield and BAU scenarios, were not demanding enough for the model to expand to wave or floating devices. A maximum of 1217 MW of bottom fixed WTGs was the only offshore generator capacity present in the scenarios. The greenfield scenarios showed that higher load (+5% for each 5-year gap, +35% in total compared to 2020 load data) resulted in less offshore wind capacity, which drooped to 684 MW.

Surprisingly, under the NECP load scenario (+160% load needed compared to 2020), bottom-fixed WTGs were reintroduced at their previous maximum, with an additional 4516 MW of floating WTGs installed. This raises questions about the model's sensitivity to load demand, particularly in scenarios that fall between the two reference cases (2050-Greenfield and 2050-NECP).

When comparing the land-use requirements of each 2050 network, constrained scenarios show a clear advantage. They allocate more capacity offshore rather than on land, reducing land use by around 2200 km^2 while meeting the same demand. The higher packing density of marine generators allows the energy system to access larger energy resources without requiring extensive onshore installations. This could be particularly important for public acceptance, as large-scale land-based developments can often face opposition due to their visual impact [59]. However, offshore installations also face limitations in site selection, as factors such as water depth, fishing zones, shipping routes, the existence of ports able to carry out transportation and installation of devices, and marine protected areas can all restrict their deployment.

The results also highlight the models' significant reliance on storage units, particularly in the higher load scenario (2050-NECP), where storage accounts for 42% of the energy mix. When combined with the extensive generator installations required across the country and its surrounding waters, this raises concerns about the feasibility of such an ambitious development. A high-share renewable energy system inherently requires over-installation of generators, as climate variability may cause resource availability to fluctuate across different regions.

Another major concern that is often overlooked, due to cost optimal solution, in the 2050-NECP high-load scenario is land use. While PyPSA-Eur optimizes for cost, other factors also influence energy system development. This scenario allocates a third of the country's onshore land to solar panels and WTGs, while only 676 km^2 is offshore. As previously mentioned, bottom fixed WTGs reached 1217 MW (174 km^2), suggesting a capacity limit at the buses where they are attached to, as it was the maximum installed in any scenario. The remaining offshore area is occupied by floating WTGs, which appear essential for meeting the high load demand.

However, if social concerns necessitate reducing onshore installations, Fig. 2 highlights the vast spatial potential for marine generators. Expanding offshore capacity would increase system costs, as marine devices are more expensive. The expected conflicts with land/sea use and reduction of local opposition is not well addressed in modeling results. Nevertheless, a higher-share marine energy system would need additional simulation to assess its hourly performance, given the variability of climate patterns, and dictate the appropriate locations for more installations.

On a broader scale, even if Greece does not reach the high-load forecast of 2050-NECP, marine installations may still be necessary. The upgrade of cross-border energy networks could lead to higher production and export demand. With many Balkan countries having little to no access to marine energy and large mountain ranges that impede onshore developments, Greece could become a significant energy provider, contributing to regional sustainability and energy security.

5. Conclusions

According to the models in this study, the potential for marine renewable energy installations in Greece is closely tied to the network's load level. While wave and floating solar power were not deployed, offshore wind power was installed in the central Aegean and Cretan Seas. Bottom-fixed WTGs were used in all scenarios, whereas floating WTGs were introduced only in the high-load (2050-NECP) scenario surpassing the fixed ones, and reaching a total offshore WTG capacity of 5.7 GW, far exceeding the 1.9 GW outlined in the NECP 2050 guideline. Additionally, the simulated 2050-NECP scenario deployed nearly 27 GW of hydrogen technologies, while the report primarily allocates hydrogen for sectoral applications (transportation and off-grid industry).

Beyond the model's numerical constraints — such as generator rated power, packing density, grid expansion, proximity to infrastructure, protected areas, water depth, and shipping routes — there are also societal and qualitative factors. The 2050-NECP scenario proposes a coverage of one third of Greece's available land for renewable installations, even after excluding protected areas and applying minimum setback distances. Land-use concerns could potentially influence the deployment of both onshore and offshore energy sources. However, the reduced visual impact of higher-capacity offshore installations may provide them with an advantage, facilitating their greater integration into the energy system.

CRediT authorship contribution statement

Lefteris Mezilis: Writing – original draft, Visualization, Software, Resources, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **George Lavidas:** Writing – review & editing, Resources, Project administration, Methodology, Investigation, Formal analysis, 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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