Are there preferable capacity combinations of renewables and storage? Exploratory quantifications along various technology deployment pathways

Serafeim Michas[a], Alexandros Flamos[a,*]

[a]*Technoeconomics of Energy Systems laboratory (TEESlab), Department of Industrial Management and Technology, University of Piraeus, Karaoli & Dimitriou 80, Piraeus 18534, Greece*

A R T I C L E I N F O

Keywords:

Renewable Energy Sources

Battery Energy Storage System

RES Integration

Curtailment

Power System

Energy Transition

A B S T R A C T

The decarbonization of the electricity sector is at the core of the European agenda, with renewable energy sources playing a leading role. A major challenge emerging with increasing shares of intermittent renewables is their efficient integration. To overcome this challenge, electricity storage systems are identified as components which will be inseparable from renewable generation in the following years. However, what are the available pathways for the capacity evolution of each generating technology? How do different capacity combinations perform in terms of pledged renewable penetration targets and investment costs? Is there an optimal capacity combination of renewables and storage? This article presents a modelling framework featuring detailed storage operation simulation and adaptive policy design, assessing these inquiries. To demonstrate its applicability, it is used to explore plausible wind, solar, and storage configurations in Greece. The results suggest that the proportions of wind and solar power is significantly affecting the timing and required capacity for storage, the potential for renewable electricity integration, as well as the costs needed for their achievement. Overall, the study demonstrates feasible pathways leading from the current status quo in Greece and towards the milestone horizon of 2030, concluding with key implications for policy and practice.

Nomenclature

Abbreviations

AIM	Adaptive policImaking Model	PHS	Pumped Hydro Storage
BESS	Battery Energy Storage System	PV	Photovoltaics
BSAM	Business Strategy Assessment Model	RES	Renewable Energy Sources
EC	European Commission	SENTINEL	Sustainable Energy Transitions laboratory
EU	European Union	STREEM	STorage RequirEmEnts and dispatch Model
EAC	Equivalent Annual Cost	TEESlab	TechnoEconomics of Energy Systems laboratory
Li-Ion	Lithium Ion	TEEM	TEESlab Modelling
NECP	National Energy and Climate Plan	US	United States
O&M	Operation and Maintenance	WT	Wind Turbines

Indices and Sets

* Corresponding author: Technoeconomics of Energy Systems laboratory (TEESlab), Department of Industrial Management and Technology, University of Piraeus, Karaoli & Dimitriou 80, Piraeus 18534, Greece.
E-mail address: aflamos@unipi.gr (A. Flamos)

i	iteration	t	Simulation period in hours
m	Number of years in the analysis horizon	$tech$	Technology assessed
n	Final year of analysis	y	Year of reference
p	Number of policies under investigation		
Parameters			
DoD	Depth of Discharge	$round\_trip$	Round-trip efficiency
$Duration$	Time required to fully charge/discharge a storage system at rated power capacity	$Target_{Curt}$	Targeted annual curtailment percentage
PV	Photovoltaics capacity	WT	Wind turbine capacity
Variables			
$Curt$	Yearly curtailment percentage	$PVOM$	O&M cost for each unit of photovoltaics
nc	Nominal capacity of the storage system	SC	Overnight investment costs for each unit of storage
$Ov.Cost$	Overnight investment cost	$slope$	Slope of curtailment decrease with storage capacity increase
$P.Cost$	Pathway cost	SOC	State of Charge
$P_{ch,t}$	Maximum charging power at simulation period t	$STOM$	O&M cost for each unit of storage
$P_{dis,t}$	Maximum discharging power at simulation period t	$WTOM$	O&M cost for each unit of wind turbines
PVC	Overnight investment costs for each unit of photovoltaics	WTC	Overnight investment costs for each unit of wind turbines

1. Introduction

The Green Deal published by the European Commission (EC) in late 2019, set the target for zero greenhouse gas emissions by 2050, pledging decoupling of economic growth from resource use. A critical component towards this direction is the decarbonization of the energy sector, which is reported to account for over 75% of the total greenhouse gas emissions in the European Union (EU). In this respect, the need to develop a power sector based on renewable energy sources (RES) is acknowledged (European Commission, 2019). Accordingly, member states, following also the Regulation on the Governance of the Energy Union and Climate Action (The European Parliament and the Council of the European Union, 2018), have already drafted their National Energy and Climate Plans (NECP), incorporating targets for renewable capacity expansion until 2030.

However, a major challenge emerging with high RES shares in the electricity mix is the intermittent nature of RES-generated electricity, which poses difficulties in their integration (Antweiler, 2021), potentially leading to curtailment (Jorgenson et al., 2018). While curtailment is an established method for managing excess RES generation and ensuring safe network operation (Michas et al., 2019), instances of curtailment enforcement should be limited, as its application reduces the amount of exploitable renewable electricity (electricity is wasted) (Chang and Phoumin, 2021), and entails financial losses for RES generators (Mayyas et al., 2022). In fact, the EU regulation 2019/943 on the internal market design (European Parliament and the Council, 2019), clearly states thata curtailment should be held at a minimum and not exceed 5% of the annual RES electricity generation. Storage and demand response are two complementary technologies which can reduce the application of curtailment and increase the exploitable renewable generation. Demand response shifts demand to high generation hours, and storage shifts generation to high demand hours. The rollout of both technologies faces difficulties that need to be overcome, such as the high investment costs for storage, and the challenge of attracting participants to demand response programmes, as well as managing their loads (Denholm, 2015). With respect to the cost of storage, a sharp decrease is being reported in the recent years, with 70% reduction observed between 2015 and 2019 in utility-scale battery storage costs (EIA, 2020). On the other side, the participants response to demand response signals is highly random, adding uncertainty to the reliability of this technology in providing services to the grid. If reliability cannot be ensured, system operators, could limit demand response application to activities not interfering with system security, such as night-valley filling, which is already incentivised through time-of-use tariffs (Oconnell et al., 2014). While both technologies will have a role in the future, considering the above, and given that the REPowerEU plan (European Commission, 2022) published by the EU in 2022 gives special attention to energy storage as a means to provide flexibility to the system and facilitate RES integration, the focus of this article is placed on energy storage acting as a supplement to efficient renewable generation.

In literature, many studies exist addressing the subject of up to 100% renewable energy systems as thoroughly reviewed by Hansen et.al. (2019) and Breyer et.al. (2022), with solar photovoltaics (PV) and wind turbines (WT) mentioned as central pillars in most transition pathways, alongside energy efficiency measures. As PV and WT are identified as the most profitable among the RES options (Buonomano et al., 2018) which are likely to have increasing shares in the electricity generation mix in the future (Christoph Soini et al., 2019), it could be expected that storage will be largely used to store solar- and wind-generated electricity. In this respect, several studies in the scientific literature have focused on research combining PV, WT and storage. Cebula et.al. (2018) synthesize studies focusing on Germany, the United States (US) and the EU level, to investigate the storage requirements per share of variable renewable electricity, discussing also the effect of PV or WT preponderance and of the detail of grid modelling on storage needs. Johlas et.al. (2020) study the storage requirements for 100% and nearly 100% solar- and wind-powered systems, in the Midcontinent Independent System Operator energy market in the central US, under the effects of various PV and WT generation shares, geographical distribution of generation technologies, RES overcapacity and balancing power availability. Goteti et.al. (2019) study the potential of storage, operated for energy arbitrage (storing electricity when prices are low to supply it back to the grid when prices are high), to achieve carbon emissions reduction. They investigate the required wind and solar capacity to marginally achieve emission reductions, considering also the effect of natural gas prices, by performing case studies in a coal-heavy and a non-coal-heavy electricity region in the US. Budischak et.al (2013) simulate a wide range of PV, WT and storage configurations, to find least-cost electricity generation mixes, considering different storage technologies, geographical sitting expansion and RES technology diversification. Their simulations are constrained by the number of hours PV and WT need to cover demand, reaching up to 99.9% of the load hours (remaining demand is met by fossil back up plants), allowing for RES overcapacity to achieve such targets. Weitemeyer et al. (2015) investigate the effect of storage and its parameters (i.e., capacity and efficiency) on the renewable integration levels, by using Germany as case study. The study is performed, by analyzing in parallel optimal wind and solar generation shares, under the effect of overcapacity. Nayak-Luke et.al (2021) explore the storage magnitude (percentage of demand that needs to be met by stored electricity) and storage duration (short-/long-term) requirements, as a function of renewables penetration, wind and solar generation shares, and location, by considering a total of 37 locations in the United Kingdom and Australia. Heide et.al (2010) quantify optimal wind and solar generation mixes in Europe and their respective storage needs, considering a 100% wind-plus-solar only scenario and a transitional scenario allowing for fossil and nuclear power generation.

From the literature sources reviewed, several scientific gaps were identified, which are summarized subsequently:

- Research so far has mainly focused on analysing PV, WT and storage configurations, towards 100% RES electricity systems, without limitation in the total RES capacity, or reference to the implementation horizon of such electricity systems. This means that the focus is on studying an incremental increase of RES share, without answering **when** can this share be realized, **how much** RES capacity can realistically (or is planned to) be installed, and with **which** storage specifications. Therefore, the gap is in studying PV, WT and storage configurations, considering in parallel (i) a tangible time horizon (e.g., 2030), (ii) reported RES capacity expansion projections and (iii) established technical specifications of storage technologies.
- RES overcapacity is a usual parameter considered in literature, allowing curtailment to act as a means for managing excess generation and limiting the need for storage capacity. In fact, overcapacity is usually used as a parameter affecting the optimal PV and WT shares in the electricity mix, which in turn limit the storage capacity required. While such a strategy is mentioned as a cost competitive alternative to deploying energy storage, especially considering the falling prices of RES (Perez et al., 2019), it can be restricted from the available land to deploy such a volume of renewable capacity.

Indicatively, as literature suggests, in order to reach a fully renewable electricity system in Europe with a balanced technology portfolio, 2% of the total European land would need to be occupied, which is about the size of Portugal (Trondle, 2020). When considered in tandem with other constraints such as natural resource potential (e.g., solar irradiation), ground morphology, availability of transmission/distribution network, protected land (van de Ven et al., 2021), or barriers (Rai et al., 2016) and costs (Gao et al., 2022) to the installation of residential solutions, the sites available to install such a mass or renewables becomes notably narrower. Therefore, opting for a significant amount of overcapacity, would expand land use to many country sizes, could compete with other forms of land use, or could reveal injustices/dependencies among countries with different geographical, regulatory, or meteorological contexts. Taking also into account, the capacity density of WT and PV which is reported up to 19 W/m^2 and 100 W/m^2 respectively, when commercially available storage options offer a capacity density around 10^5 W/m^2 (Trondle, 2020), it becomes evident how much more hard-to-find European land would be required when considering overcapacity, and how much land use would be avoided by replacing PV or WT overcapacity with storage. Furthermore, overcapacity does not account for other issues, such as utilisation maximization of domestic resources, social acceptability issues, or investors' risk. For example, the REPowerEU plan (European Commission, 2022) published by the EC in response to the Russian invasion in Ukraine, aiming to reduce the dependency of the EU from Russian gas, mentions energy storage as a significant asset in providing flexibility to the grid and supporting security of supply, by facilitating RES integration and shifting generation to high demand times. While overcapacity with curtailment can reduce the residual demand (i.e., demand minus RES generation) during generation times, it cannot transfer electricity at times where it is most needed (e.g., peak demand, evening or night hours).

That way the value of RES is reduced since they offset less fossil generation (Denholm, 2015). Finally, literature highlights that social acceptance of RES projects is a significant challenge in the EU (Kleanthis et al., 2022), and that financing as well as the design of policy support mechanisms are critical risk factors which could affect investment in RES (Angelopoulos et al., 2017). Therefore, aiming for underutilised systems might weaken the public and investors' trust towards the sustainability of RES systems. Considering the above, the gap in this case is in studying various PV, WT and storage configurations which minimize the application of curtailment towards utility maximization of domestically-generated electricity, without bias in allowing a specific technology to dominate the RES mix.

- Finally, usually the end-state of the electricity system is the focal point of research. Indicatively, most studies focus on a "future" electricity system and analyse the effects of its possible build-outs (e.g., shares of WT and PV, overcapacity and storage trade-offs, backup fossil generation, etc.). The current status quo of the electricity system, as well as its timewise intermediate buildouts (e.g., yearly PV, WT and storage configurations) leading to the materialization of a desired end-state, is usually neglected. This is in line with Hansen et.al (2019) whose extensive literature review highlighted that most studies do not analyse transition pathways (i.e., how to reach a target) and therefore do not provide information to policy-makers answering the “when's” and “how's” of the energy transition. In other words, the gap identified, can be expressed with the following four questions: (i) What is the current electricity generation portfolio? (ii) What RES plus storage configurations are feasible in a tangible time horizon (e.g., 2030), (iii) Which PV, WT and storage configurations can be implemented in the intermediate years, and (iv) What are their implications in terms of RES integration pace and timing of storage capacity requirements under various PV and WT shares?

This study aims to address the above research gaps by using a methodological framework consisting of two soft-linked models which: (i) enable the identification of storage capacity requirements, based on high-resolution storage operation simulation, and detailed technical specifications, such as round-trip efficiency, depth-of-discharge and energy-to-power ratio, and (ii) facilitate the interactive design of policy pathways, by providing an interface for simulated policy implementation. Greece is chosen as the testbed, as a country which has set ambitious RES capacity targets for 2030 and is currently characterized by limited capacity of interconnection transmission lines compared to its peak demand (i.e., about 20%), and high dependency on imported fuels for electricity generation. This makes the country a good example for assessing RES integration maximization in an effort to rely more on domestic resources. To make this article policy-relevant, actual market inquiries are addressed, which are either directly expressed by, or validated with, Greek stakeholders and market experts.

Overall, to the best of the authors knowledge, the novel contribution of this paper is twofold:

- The presentation of a modelling framework, which aggregates for the first time the merits of individual studies and evaluates RES plus storage configurations of electricity systems, considering simultaneously: (i) specific RES capacity targets, decomposed in various configurations of PV and WT shares without bias regarding the optimality of each configuration based on specific criteria (e.g., cost minimization), (ii) curtailment limitation under user-defined thresholds, using storage with detailed representation of its technical characteristics, (iii) RES integration percentages embedded in actual timewise implementation plans, and (iv) current status quos as well as the pathways towards diverse end-system configurations.
- The answering of inquiries expressed directly, or validated with, policymakers, aiming to support informed decision making. More precisely, taking into account actual RES capacity targets, and considering available technologies and a tangible time horizon, this study answers critical questions

that still remain to be answered in the course of the energy transition in Greece. The timing of their answering coincides with the revision process of the Greek NECP, which is currently ongoing.

The remainder of the paper is organized as follows: **Section 2** presents the modelling framework used. **Section 3** describes the Greek context in which the modelling framework is applied to. **Section 4** reports detailed simulation results. **Section 5** discusses key takeaways of the study accompanied with comparative analysis with relevant studies where possible. Finally, **section 6** summarizes key lessons learnt and provides implications for potential policymakers and end-users.

2. Modelling framework

The modelling framework used in this study consists of **(i)** the **ST**orage **R**equir**E**m**E**nts and dispatch **M**odel (STREEM), which enables the identification of the storage capacity requirements of a region, towards user defined curtailment levels, and **(ii)** the **A**daptive Pol**I**cymaking **M**odel (AIM) which performs exploratory analysis on a variety of policy options, and visualizes a map of diverse policy sequences, whose implementation lead to a desired outcome (Michas et al., 2020). The modelling framework is part of the **T**echno**E**conomics of **E**nergy **S**ystems **lab**oratory (**TEE**Slab) **M**odelling Suite (TEEM Suite[1]) and has been further developed in the context of the Sustainable Energy Transitions laboratory (SENTINEL[2]) project, based on consultations performed with relevant stakeholders (Süsser et al., 2022). Fig. 1 shows a high-level overview of the modelling framework, while the following subsections present the models in more detail.

[1] https://www.i2am-paris.eu/detailed_model_doc/teemsuite

[2] https://sentinel.energy

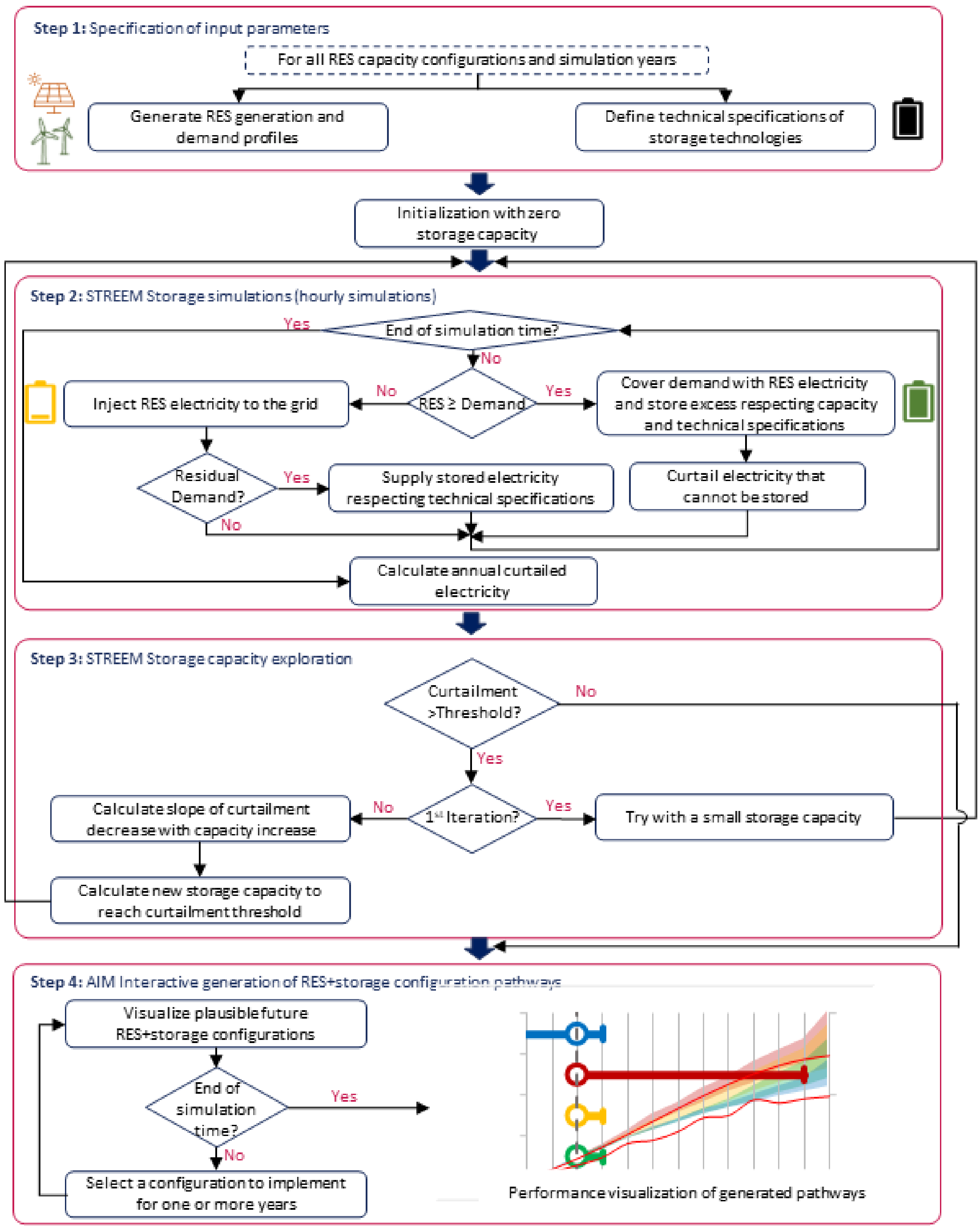

Fig. 1 Methodological Flowchart

2.1. ***STREEM***

STREEM builds on the battery energy storage system (BESS) dispatch algorithm presented by Quoilin et.al. (2016), adapted to the temporal (i.e., hourly) and spatial (e.g., provincial, national, international) resolution of STREEM, and extended to account for storage capacity requirements investigation. The input parameters used by STREEM are summarized in Table 1, while the dispatch and storage capacity calculation algorithms are presented subsequently.

Table 1
STREEM inputs

Input Parameter	**Description**
Nominal Capacity	Maximum energy that can be stored in the storage system
Demand and RES generation timeseries	Projected electricity demand and generation from various RES sources in an hourly resolution for the entire simulation period
Duration	The time interval for which the storage system can charge/discharge at rated power capacity until full/emptied
Depth-of-Discharge (DoD)	The percentage of energy that can be discharged relatively to the nominal capacity of the storage system
Round-trip efficiency	The percentage of stored energy that can be retrieved during a full cycle of the storage system

Sources: (Cole et al., 2021; HOMER Energy, 2020; MIT Electric Vehicle Team, 2008)

2.1.1. Storage dispatch algorithm

The algorithm runs in an hourly resolution for each year of the simulation period. The initial state of the storage is set at minimum State of Charge (SOC), as described by Eq.(1).

$$SOC_{t=0} = nc * (100 - DoD) \qquad \text{Eq.(1)}$$

where:

- t is the simulation period in hours,
- nc is the maximum energy that can be stored, and

- DoD is the depth-of-discharge of the storage system.

At each hour of the simulated period, the storage system stores electricity when RES generation is higher than demand, and supplies electricity to the grid when demand is higher than RES generation. If multiple storage technologies are used, the algorithm prioritizes short-term storage (e.g., battery energy storage systems) and uses the medium-/long-term storage technologies (e.g., pumped-hydro storage) after the short-term options have reached their storage capacity, or DoD. Excess generation that cannot be stored is curtailed. The hourly demand that could not be met either by directly feeding RES electricity to the grid or by discharging the storage systems, is saved as a residual demand timeseries.

At each simulation period t, the maximum charging power ($P_{ch,t}$), the maximum discharging power ($P_{dis,t}$), and the SOC of the battery are updated using Eq.(2)-(4)

$$P_{ch,t} = min\left(\frac{nc}{Duration}, nc - SOC_{t-1}\right) \qquad \text{(Eq.2)}$$

$$P_{dis,t} = min\left\{\frac{nc}{Duration}, round\_trip \cdot [SOC_{t-1} - nc \cdot (1 - DoD)]\right\} \qquad \text{(Eq.3)}$$

$$\begin{aligned} SOC_t &= SOC_{t-1} + P_{ch,t}\ , \text{ if storage is charging} \\ SOC_t &= SOC_{t-1} - \frac{P_{dis,t}}{round\_trip}, \text{ if storage is discharging} \end{aligned} \qquad \text{(Eq.4)}$$

where:

- $Duration$ is the charge/discharge duration, and
- $round\_trip$ is the round-trip efficiency of the storage system

Storage losses are modelled during discharge of electricity, represented by the effect of the round trip efficiency in Eq.(3) and (4).

It should be noted that:

- Curtailment is calculated as the excess generation from RES that cannot be accommodated to the grid due to lack of demand. The model assumes that all generated electricity from the various RES technologies is aggregated and managed centrally, and that storage options are modelled as aggregated units per technology, representing an ideal "sum" of distributed systems. Therefore, restrictions related to grid-specific constraints (e.g., transformer availability, power flows, number of buses, etc.) are not considered. This enables a simplified representation of the power system allowing multi-spatial application of the model, spanning from cities to multi-country level analyses, aiming to provide high-level, policy relevant answers to challenges related to energy storage.
- The residual demand timeseries that results from the storage dispatch algorithm can be fed in a unit-commitment and economic dispatch model, to calculate the optimal dispatch of thermal units, imports, or other dispatchable units, for the demand not covered by RES. With this soft link technique of STREEM with unit commitment and economic dispatch models, RES generation (either direct or stored) is by priority injected to the grid, storage is used to store only RES electricity, and non-renewable generation is used to cover only the residual demand. The authors have successfully attempted such a link with the Business Strategy Assessment Model (BSAM) (Kontochristopoulos et al., 2021). Relevant results for the residual demand are not in the scope of this study and therefore are not included.

2.1.2. Required storage capacity algorithm

The algorithm investigating the storage capacity requirements, identifies the correlation between storage volume and curtailment decrease. Initially the storage capacity is set at zero, representing a no storage energy system. The storage dispatch algorithm is run and the annual curtailment without storage is calculated. Following, a small capacity of storage is simulated, and the new annual curtailment is calculated. With these two initial iterations, the instantaneous slope of curtailment decrease with storage capacity increase is calculated using Eq. (5).

$$slope = \frac{nc_{i-1} - nc_{i-2}}{Curt_{i-2} - Curt_{i-1}} \quad \text{(Eq.5)}$$

where:

- i is the iteration of the algorithm
- nc is the nominal capacity of the storage system, and
- $Curt$ is the yearly curtailment as a percentage of total RES generation

Then, the new estimated storage capacity is calculated using Eq. (6).

$$nc_i = nc_{i-1} + slope \cdot (Curt_{i-1} - Target_{Curt}) \quad \text{(Eq.6)}$$

where:

- $Target_{Curt}$ is the target for curtailment

Considering that usually the correlation of curtailment with storage capacity is non-linear, the storage dispatch algorithm is run for the new estimated storage capacity and calculates the new instantaneous slope of curtailment decrease with storage capacity increase using Eq. (5). With this procedure, the actual curve of storage/curtailment correlation is approximated (example in Fig. 2), regardless of the storage technology or specifications simulated, while ensuring fast convergence. In fact, simulations suggest that the algorithm converges in 6-7 iterations. Furthermore, with this stepwise procedure, storage capacity overshooting is avoided, since the storage/curtailment slope gradually decreases towards the targeted curtailment levels.

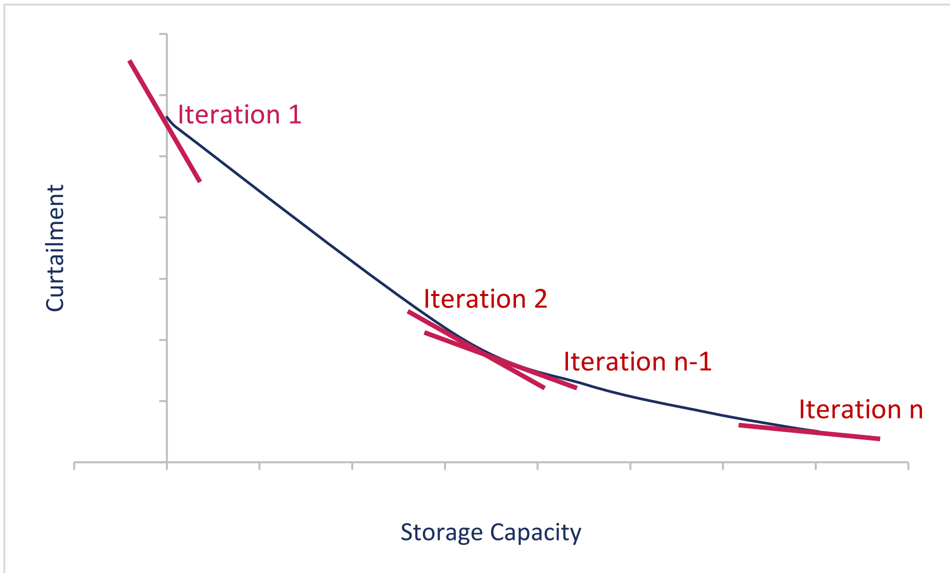

Fig. 2. Approximation of storage/curtailment curve

It is important to mention that the algorithm calculates the storage requirements of a single technology at a time, while keeping the other technologies at constant capacity. Such a simulation concept goes beyond classic optimization based on specific criteria (e.g., least investment cost, least operational cost, arbitrage maximization, etc.). Instead, the user is allowed to perform sensitivity analysis in terms of storage capacity requirements for different storage technologies, considering also the storage status quo of a region, or technology-specific constraints (e.g., long construction times and sites available for pumped hydro storage, maturity of technologies, etc.).

2.2. ***AIM***

AIM is a decision support model which facilitates robust decision making under uncertainties and supports the development of policy pathways towards a desired target, based on simulated policy implementation and outcome assessment. It is a plug-in model, meaning that it requires as input, both the input parameters as well as the respective outputs, which are produced by a simulation model. In this respect it performs meta-analysis of simulation results. The main strength of AIM is that it enables fast assessment of a large number of scenarios along an analysis horizon, without mandating the same number of simulations to be performed by computational- and time-intensive simulation models. Specifically, it enables the assessment of $p^{m,}$ policy development scenarios with only p policy simulations performed by a simulation model, where p is the number of policies under investigation and m the number of years in the analysis horizon. The analytical formulation of AIM is presented in Michas et. al. (2020). In this paper, AIM is adapted to match the scope of the herein presented modelling endeavor. Target is the generation of yearly adaptive pathways, comprising of changing RES plus storage configurations, towards higher RES integration levels with minimum curtailment.

Initially, AIM investigates if a specific PV-to-WT ratio (i.e., policy pathway), with relevance to the total RES capacity, is feasible from a stakeholder's "today" and onwards, considering the already installed capacities of each technology. Feasible pathways are those that do not result in less installed capacity of PV, WT or storage in a later year, than that installed in an earlier year, given that the lifespan of technologies has not been exceeded. Stakeholder's "today" is defined as the start of simulation time which coincides with the actual year of the problem analysis. Valid PV-to-WT ratios are depicted in an adaptive pathway map, showing which PV-to-WT ratios can be implemented starting from the stakeholder's "today", and which PV-to-WT ratios can be implemented in later years.

Then, with the simulated policy implementation functionality of AIM, PV-to-WT ratios are implemented in a stepwise manner. A feasible PV-to-WT ratio is implemented for a selected number of years, and the adaptive policy pathway map is updated within seconds, showing which PV-to-WT ratios are feasible for the years following the last year a PV-to-WT ratio was implemented. Policy implementation goes on until the end of simulation time is reached. During this process, the outcome of the implemented pathway (sequence of PV-to-WT ratios), as well as the outcome of "future" PV-to-WT ratios is displayed to the user. The outcomes along the pathway (or "future" pathways) comprise of: (i) the required storage capacity, (ii) the annual and peak curtailment levels with and without storage, (iii) the RES integration levels with and without storage, (iv) the peak residual demand that needs to be covered by thermal generating units, and (v) the pathway costs (i.e., capital cost and operation and maintenance (O&M)), decomposed to the cost of each technology (i.e., PV, WT and storage).

The outcomes (i)-(iv) result from simulations performed with STREEM. The pathway costs are the product of post-processing STREEM outputs with AIM. At each year of the pathway, the newly installed capacities per technology are calculated and multiplied with the discounted overnight investment costs and O&M costs at the same year as shown in Eq. (7) and Eq. (8) respectively, to derive the pathway's yearly overnight investment costs and O&M costs.

$$\begin{gathered} Cost\ of\ PV_y = \left(PV_y - PV_{y-1}\right) \cdot PVC_y \\ Cost\ of\ WT_y = \left(WT_y - WT_{y-1}\right) \cdot WTC_y \\ Cost\ of\ Storage_y = \left(nc_y - nc_{y-1}\right) \cdot SC_y \\ Ov.Cost_y = Cost\ of\ PV_y + Cost\ of\ WT_y + Cost\ of\ Storage_y \end{gathered} \qquad \text{(Eq.7)}$$

$$\begin{gathered} O\&M\ cost\ for\ PV_y = \left(PV_y - PV_{y-1}\right) \cdot PVOM_y \\ O\&M\ cost\ for\ WT_y = \left(WT_y - WT_{y-1}\right) \cdot WTOM_y \\ O\&M\ cost\ for\ ST_y = \left(nc_y - nc_{y-1}\right) \cdot STOM_y \\ OM.Cost_y = O\&M\ cost\ for\ PV_y + O\&M\ cost\ for\ WT_y + O\&M\ cost\ for\ ST_y \end{gathered} \qquad \text{(Eq.8)}$$

where:

- y is the year of reference
- PV, WT, nc are the simulated PV, WT and storage capacities in the year referenced by the index,
- $PVC, WTC\ and\ SC$ are the overnight investment costs for each unit of PV, WT and storage in the year referenced by the index, and

- $PVOM, WTOM\ and\ STOM$ are the O&M costs for each unit of PV, WT and storage in the year referenced by the index

Then, the Equivalent Annual Cost (EAC) of the yearly overnight investment costs of each technology are calculated using Eq. (9).

$$EAC_{y,tech} = \frac{Ov.Cost_{y,tech} \cdot i_{tech}}{1 - (1 + i_{tech})^{-k_{tech}}} \quad \text{(Eq.9)}$$

where:

- i is the interest rate,
- $tech$ is the technology assessed, and
- k is the lifetime of each technology

Finally, the pathways total cost is calculated as the sum of equivalent annual values and O&M costs until the pathway's horizon of analysis as shown in Eq. (10).

$$P.Cost = \sum_{y=1}^{n} \left[\left(\sum_{tech} EAC_{tech} \right)_y + OM.Cost_y \right] \quad \text{(Eq.10)}$$

where:

n is the final year of analysis.

It should be noted that Eq. (10) is not an objective function subject to minimizing. It only calculates the cost of each generated pathway. Cost minimization is possible, but it is out of the context of this work.

3. The case of Greece

Greece is chosen as the case study region, being a country which has set ambitious climate and policy goals for 2030, transitioning away from its current regime which is characterized by low interconnections' capacity, high dependency on fossil fuels and lately high dependency on imported fuels for electricity generation. The Greek NECP (Greek Ministry of Environment and Energy, 2019a) published in December 2019 describes the set targets, as well as, how they are intended to be achieved. Among the targets is the decarbonization of the power sector, presenting ambitious renewable capacity expansion objectives, as well as projections about the evolution of the generation capacity mix (i.e., installed capacities of solar, wind, hydro, thermal, etc. generating units). Specifically, the gradual phase out of the highly polluting lignite power plants until 2023 is the starting point for the decarbonization of the power sector, with natural gas playing the role of the transition fuel. Target destination is a power sector dominated by RES technologies, mentioning a cumulative RES capacity in 2030 amounting to 14.7GW, implying a growth rate equal to 153% with relevance to the installed capacity in 2020 (i.e., 5.8GW). The 2022 Russian invasion to Ukraine and the consequent energy crisis might shortly delay the lignite phase out plan of Greece, but sooner or later Greece will be in a position where all dispatchable power plants operated with domestically produced fuels will be shut down, and Greece will rely only on gradually declining amounts of imported gas and gradually increasing amounts of intermittent RES to cover its electricity needs. Considering the above, the need for electricity storage has been identified in the Greek NECP, as the means for optimal integration of uncontrollable RES, avoiding the risk for significant curtailment which would make new RES projects unsustainable for investors (Aposporis, 2022). Specifically, storage capacity equal to 2.8GW is foreseen until 2030, comprising mainly of pumped hydro and battery storage.

However, as stated in the official NECP, the amounts of installed capacity of the various generating and storage technologies, have been calculated based on simulations made under specific assumptions regarding the generation cost evolution for each technology. In this respect, the configuration of the electricity system presented in the NECP should be considered as possible but not binding (Greek Ministry of Environment and Energy, 2019a). This statement becomes even more relevant considering the 2022 energy crisis that followed the Russian invasion to Ukraine, which increases the uncertainty for natural gas availability, and implicitly mandates for maximization of utilization of RES-generated electricity.

In this respect, in this study, various configurations of PV, WT and storage configurations are analyzed, as potential buildouts of the Greek electricity system in 2030, providing implications for their renewable integration potential, the needs for storage capacity to maintain curtailment below 0.1%, the pathways towards their materialization, as well as, their overnight investment costs. The small curtailment window is left open to account for exceptional events, with concurrent high solar irradiation and wind speed, during which the storage systems may reach their capacity, or the hourly electricity to be stored may exceed the storage systems' rated charging power.

Important research questions tackled include:

i. How much storage is needed to reach the 2030 renewable integration targets in Greece without excessive curtailment, maximizing that way the utilisation of domestically produced electricity?
ii. How do the PV and WT capacity shares relate to RES integration and storage needs timing?
iii. Is there an optimal wind/ PV ratio to achieve efficient RES penetration with low curtailment, and how much storage does this configuration require?
iv. What is the cost of each additional percent of RES generation injected to the system?

These research questions have been either directly expressed by, or validated with, Greek stakeholders, during the stakeholder consultation workshops that were held in mid-2020 as part of the EC-funded SENTINEL project. Their answering aim to contribute to the work of policymakers, by providing implications for a wide range of electricity system configurations which are not a product of optimization based on specific criteria. Moreover, it contributes to the endeavors of the scientific community, by bridging the gap between scientific analyses and targeted policy inquiries. The following subsections present the assumptions of the study.

3.1. ***Demand, hydro, and RES generation***

Historical demand, hydro generation and RES generation (i.e., PV and WT) timeseries in an hourly resolution for the period 2015-2020 were obtained from the ENTSO-e transparency platform (ENTSO-e Transparency Platform, 2021), and were scaled to their respective annual projections, as mentioned in the NECP for the period 2021-2030. Randomization in each projected timeseries was performed by drawing from a normal distribution with mean the average amounts (e.g., demand, hydro, wind and solar generation) for each hour of the historical calendar years (2016 – 2020), and standard deviation the standard deviation of each timeseries for each hour of the same period. Fig. 3 shows the annual demand projections as well as a typical demand profile throughout a year.

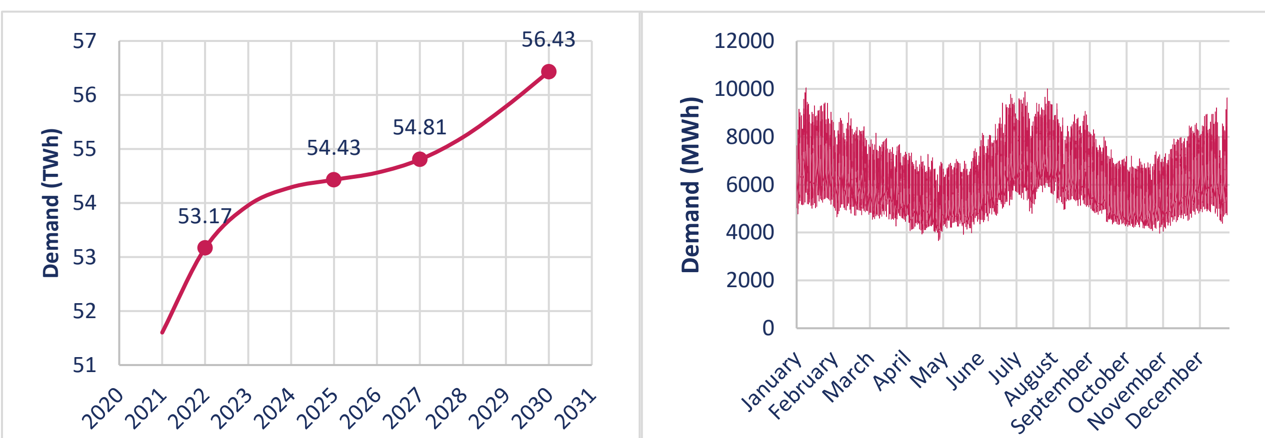

Fig. 3. Electricity demand in Greece

Hydro power plants' capacity (i.e., hydro run-of-river and hydro water reservoir) in Greece is not expected to change significantly by 2030. Therefore, the hourly hydro timeseries were only randomized according to the historical data obtained by ENTSO-e. Fig. 4 shows a typical hydro generation profile throughout a year.

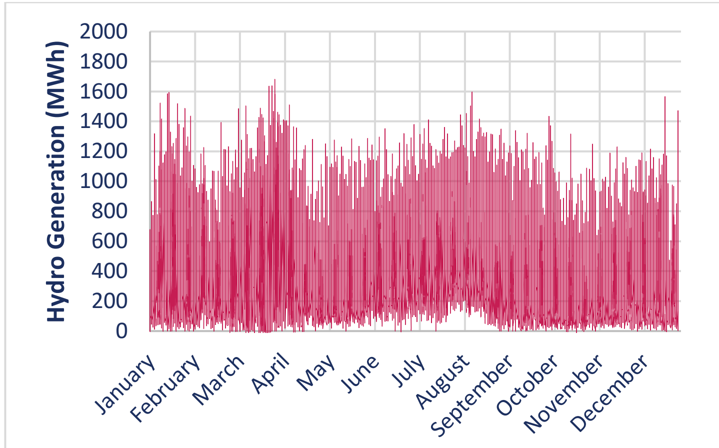

Fig. 4. Hydro generation in Greece

Finally, for the case of RES generation, as mentioned earlier in section 3, various PV-to-WT capacity configurations towards the aggregated RES capacity targets (i.e., 14.7 GW in 2030) are simulated. In fact, configurations featuring from 75% WT to 75% PV with 2.5% steps are included in the scenarios. Therefore, the generation profiles differ according to the shares of PV and WT in the RES capacity mix. Fig. 5 show the range of scenarios examined for RES (i.e., PV and WT) capacity and generation until 2030. The coloured capacities are the ones projected by the Greek NECP, while the grey ones are the maximum and minimum capacities that each technology can hold along the years in the assessed scenarios. The thick RES generation lines are the ones projected by the Greek NECP, while the shaded areas correspond to the generation range of each technology, depending on the capacity it holds within the maximum and minimum range of the assessed scenarios.

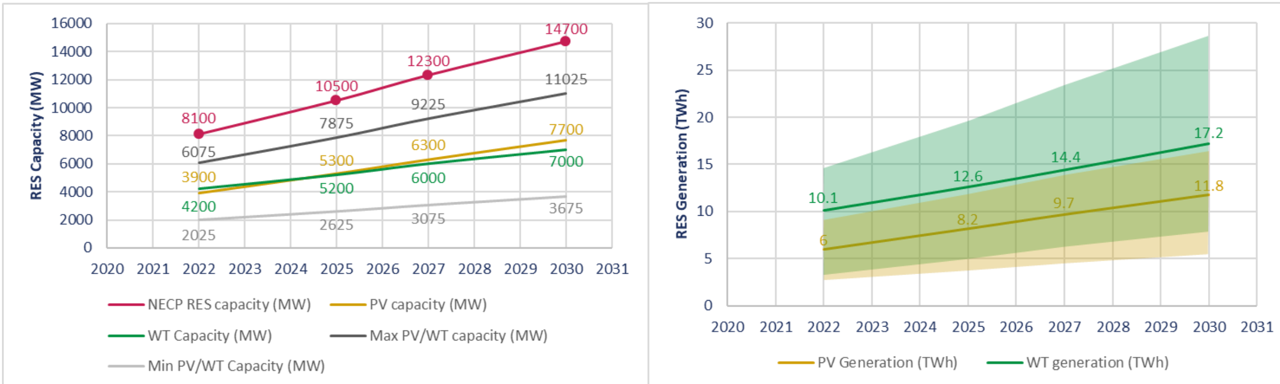

Fig. 5. Range of scenarios examined for RES capacity (left) and generation (right) in Greece

3.2. *Storage Characteristics*

Storage can provide a multitude of functions to the power grid and each storage technology is better suited for different applications as analytically presented by Palizban and Kauhaniemi (2016). This study does not intent to analyse the optimal storage technology mix for the services required by the power sector in Greece. Instead, the aim is to analyse the storage capacity needs under different RES generation configurations, considering current trends in Greek power storage, and an established and widely used storage technology as reference for future capacity expansion. As mentioned in the Greek NECP, storage capacity until 2030 will comprise mainly of pumped hydro and battery storage. Pumped hydro storage (PHS) is historically the most established method for storing and dispatching electricity, with main benefits being its almost infinite lifetime and high efficiency. PHS storage is suitable for bulk energy (i.e., energy arbitrage, peak shaving) and renewable energy integration applications (i.e., capacity firming, time shift), with potential for some ancillary services provision (e.g., secondary and tertiary frequency regulation or black start) (Palizban and Kauhaniemi, 2016). An important limitation of PHS, is the limited availability of sites for their geographical sitting in river-based applications (Lu et al., 2021). Nevertheless, the availability of sites for off-river, closed loop pumped hydro has been recently studied and the results were promising (Stocks et al., 2021). On the other hand, BESS, are increasingly attracting the attention of the scientific community (Gaspar et al., 2021; Kalkbrenner, 2019; Retna

Kumar and Shrimali, 2021). The advantages of BESS, as identified by Hannan et. al (2021), include their fast and steady response, their adaptability and controllability, as well as their geographical sitting flexibility, which is a significant differentiation from PHS. BESS have the potential to contribute to a variety of ancillary services (e.g., voltage support, black start, primary/secondary/tertiary frequency regulation, etc.), customer energy management (i.e., power quality, power reliability) and renewable energy integration (IRENA, 2019; Palizban and Kauhaniemi, 2016), and is identified as the storage technology which is expected to provide much flexibility to the grid with increasing renewable generation (Seward et al., 2022).

Currently in Greece, there are two hydro power stations with installed pumping capacity (namely in the Sfikia and Thisavros power plants). According to consultations with stakeholders from the Public Power Corporation (owner of the power plants), there are plans to build two new PHS projects in Amfilohia and in Amari, however, due to high uncertainty regarding their delivery, they are not considered in this study. Therefore, the PHS capacity in the present study is kept constant. Table 2 presents the technical specifications of PHS.

Table 2
PHS specifications

Power Plant Name	Sfikia	Thisavros
Nominal Capacity (MWh)	1320	3820
Nominal Power (MW)	315	372
Pumping rate (MWh/h)	220	250
Depth-of-Discharge (%)	95	95
Round-trip efficiency (%)	78	78
Duration (h)	6	10

Sources: (Kaldellis, 2015; Schmidt et al., 2019) and consultations with stakeholders from the Greek Public Power Corporation (owner of the plants)

BESS capacity is currently not installed in Greece, but it is mentioned in the political agenda (Greek Ministry of Environment and Energy, 2019a). While an estimation for the power capacity of BESS systems (in GW) until 2030 is provided in the NECP other technological specifications of BESS (e.g., technology, duration, round-trip efficiency, or depth of discharge) are not included. In this study utility-scale lithium ion (Li-Ion) electricity storage systems are assumed as the BESS option, and their required energy capacity (in GWh) to minimize curtailment is investigated. Li-Ion has lately been reported as the technology which is starting to be the dominant option for energy storage at grid-scale (Martins and Miles, 2021). It is a reliable storage technology with indicative strengths being its long lifecycle, its high round-trip efficiency and its low self-discharge rate (Killer et al., 2020). According to Schmidt et.al. (2019) the technology is expected to be the most cost-efficient in terms of levelized cost of storage in most electricity storage applications by 2030. Furthermore, stakeholders (i.e., utilities, regulators, system integrators, etc.) have been gaining working experience with the technology at grid-scale applications, as such it is expected to be the dominant technology for energy storage applications at grid-scale (Pellow et al., 2020). In fact, it has been reported that over 90% of large-scale BESS installations in 2017 were of the Li-Ion technology (IRENA, 2019). Table 3 presents the technical specification of utility-scale Li-Ion BESS assumed in this study, for which capacity requirements are investigated.

Table 3
Li-Ion BESS specifications

Specification	**Metric**	**Justification**
Depth-of-Discharge (%)	88	Average optimal DoD of Li-Ion batteries for multiple applications until 2030 in terms of LCOS, as presented in Schmidt et.al. (2019)
Round-trip efficiency (%)	85	In agreement with values published in several studies reviewed by Cole et.al (2021)
Duration (h)	4	Wide application in the U.S. and cost-competitiveness with combustion turbines (Denholm et al., 2020)

3.3. *Cost components*

Projections for the overnight investment and O&M costs for PV and WT until 2030 were obtained from the Greek NECP and the Greek Long-term strategy (Greek Ministry of Environment and Energy, 2019b) respectively, performing linear interpolations for missing intermediate years. For the case of solar PV in Greece, it is assumed that for about every 7 MW of large-scale PV installations, 1 MW of small-scale PV (rooftop) installations occur, which is an assumption based on historical data (Michas et al., 2020). As such the average investment and O&M cost of PV was calculated using the same weights. For the case of 4-hour Li-Ion BESS, projections for the overnight investment costs for a complete 4-hour battery storage system, accounting for both energy (kWh) and power (kW) costs, were obtained from Cole et. al. (2021), after converting the prices from US Dollars ($\$_{2020}$) to Euros ($€_{2020}$) with the average exchange rate for 2020. O&M costs for batteries were obtained from the Greek Long-term strategy after performing linear interpolation for the missing years. Table 4 presents the resulting cost values.

Table 4
Overnight investment and O&M costs of RES and storage

Year	Overnight Solar PV (€/MW)	O&M Solar PV (€/MW)	Overnight WT (€/MW)	O&M WT (€/MW)	Overnight Storage Min (€/MWh)	Overnight Storage Max (€/MWh)	O&M Storage (€/MW)
2021	591720	21550	1126040	21900	316000	333000	30300
2022	574080	20850	1092160	21800	290000	323000	28600
2023	557455	20150	1059360	21700	264000	315000	26900
2024	541845	19450	1027640	21600	238000	305000	25200
2025	527250	18750	997000	21500	212000	295000	23500
2026	513670	18050	967440	21400	199000	286000	21800
2027	501105	17350	938960	21300	184000	276000	20100
2028	489555	16650	911560	21200	170000	267000	18400
2029	479020	15950	885240	21100	157000	258000	16700
2030	469500	15250	860000	21000	143000	248000	15000

Sources: (Cole et al., 2021; Greek Ministry of Environment and Energy, 2019a, 2019b)

The effective lifetime of WT, PV and Li-Ion BESS is assumed to be equal to 20, 32.5 and 20 years respectively as obtained by NREL (2022) and Timmons et.al. (2020). Finally, the interest rate of new investments is assumed equal to 8.5% as obtained by the Greek Long-term strategy.

4. Results

The results of the study showed that towards the Greek RES capacity targets mentioned in the NECP until 2030, several configurations can be implemented, and various pathways can be followed for their achievement. The results do not imply optimal PV, WT and storage configurations or dominance of one option over another. Rather, the aim is to highlight the outcomes of each end-system configuration, providing insights to potential end-readers, such as policymakers, research practitioners, etc.

In all PV-to-WT configurations examined (see section 3.1), the annual curtailment levels until 2030 remain below the 5% threshold mandated by the EU, without any storage capacity (Fig. 6). This is due to the fact that the installed RES capacity until 2030 is still low, and the generated electricity can, by the largest part, be matched with demand.

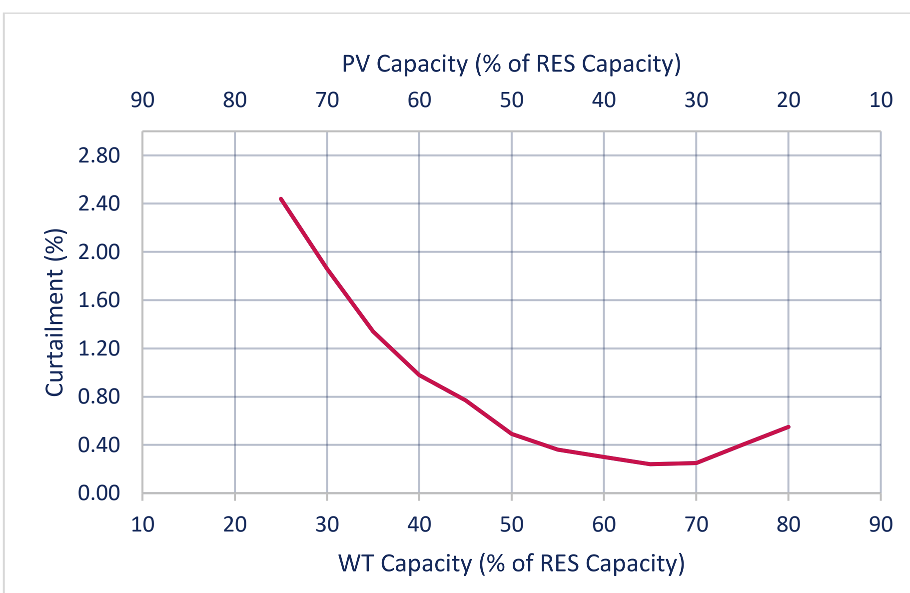

Fig. 6. Annual curtailment (%) without storage in 2030

Yet, even if curtailment remains low, it still highlights that instances of potential electricity loss will start to appear with increasing RES shares. The simulation results indicate that with BESS operating in parallel with the installed PHS capacity, curtailment could be minimized by 2030, paving the way for higher RES integration post the NECP horizon (i.e., post 2030), contributing that way to a decoupling of the energy transition of Greece from imported gas. At first glance, Fig. 6, suggests that with a WT share around 60-70% in the electricity system, the lowest curtailment levels can be achieved, thus low BESS capacity would be required. While this is true, the problem of RES integration is multifaced, and each PV, WT and BESS configuration in 2030 requires a more in-depth analysis. The following subsections present details for three end-system configuration scenarios and the pathways towards their achievement.

4.1. ***PV+ scenario***

In the "PV+" scenario, the RES plus storage configuration features PV as the preponderant technology, holding 60-75% share with respect to the total RES capacity foreseen for 2030. This corresponds to 8820-11025 MW of PV capacity and 3675-5880 MW of WT capacity.

4.1.1. BESS requirements

In this scenario, curtailment levels without BESS capacity range between 0.98-2.44%, and the RES share in the electricity mix ranges between 48.5-54.5%. The required BESS capacity to reduce curtailment below 0.1% annually, ranges between 7.6-11.7 GWh, with respective power capacity ranging between 1.9-2.9 GW. The resulting RES share in the electricity mix with the use of BESS increases to 49.3-54.9%, which is mainly attributed to the contribution of BESS in matching generation and demand during the morning peak hours as shown in Fig.7. Considering the PV shares examined, the correlation of PV share and RES integration implies a declining rate of -0.37% RES share per 1% additional PV share in the RES mix. The main drawback of such a configuration is that the mismatch between generation and demand remains high during the evening and night hours, resulting in a significant amount of peak residual demand (demand minus RES generation) that needs to be covered by thermal units, equal to 7.6-8.1GW. This also explains the low RES penetration levels observed.

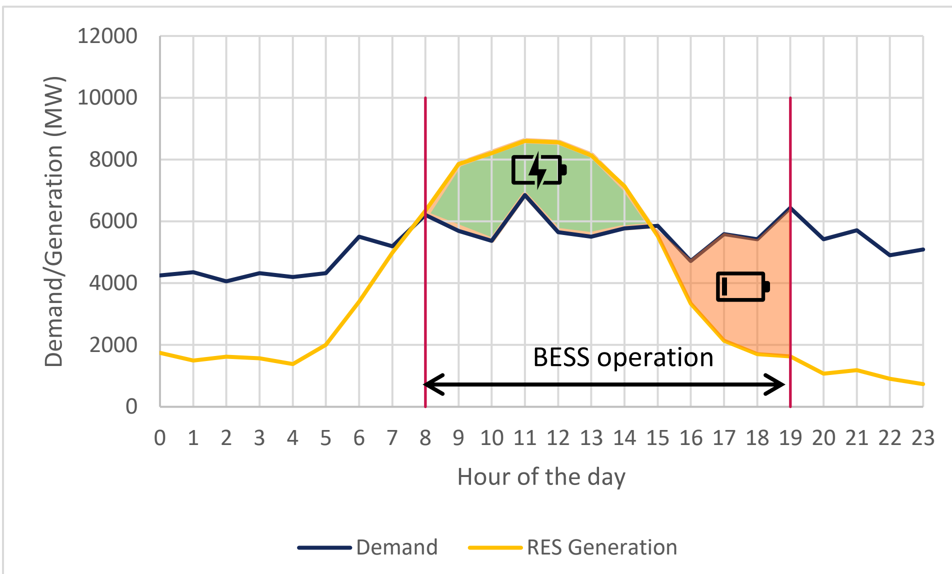

Fig. 7. BESS operation throughout a typical day with high generation in the "PV+" scenario

4.1.2. How to get there

In order to reach the end-system configuration described in the "PV+" scenario, multiple pathways exist as shown in Fig. 8. The thick lines in each subfigure represent the marginal pathways (percentage evolution of PV and WT) towards the 2030 configuration, restricted by the currently installed capacities per technology. This means that a percentage configuration above a thick line in a specific year cannot be materialized, because this would mean reduction in an already installed capacity (in this case WT), which is not desired. The shaded area within each subfigure indicates the feasible PV/WT percentages that can be followed, to generate intermediate pathways towards the final configuration target.

Fig. 8. Pathways towards the PV+ scenario. **(PV+ min):** Configuration in 2030 consisting of 60% PV and 40% WT. **(PV+ intermediate 1):** Configuration in 2030 consisting of 65% PV and 35% WT. **(PV+ intermediate 2):** Configuration in 2030 consisting of 70% PV and 30% WT. **(PV+ max):** Configuration in 2030 consisting of 75% PV and 25% WT.

Observing Fig. 8, it is easily deductible that with increasing PV shares in the end-system configuration, the pathway options towards their achievement decrease significantly, eventually, leading to the availability of only one pathway to follow (i.e., bottom subfigures of Fig. 8). Nevertheless, in order to reach an electricity system in 2030 with PV holding 60-75% of the RES capacity share, new PV installations should prevail as soon as possible in all cases of Fig. 8, in order to avoid capacity lock-ins. The choice of end-system configuration, as well as the pathway towards its materialization, can be informed by technological, as well as cost parameters.

The average BESS needs per additional RES share range between 1.1-1.3 GWh/%RES. Yet, due to the lower technological cost of PV with relevance to WT (section 3.3), the increased needs for BESS capacity with higher PV shares, increase only slightly the total annualised end-system configuration cost in 2030, and only if slow cost reductions are observed for BESS. This is graphically presented in Fig. 9, which illustrates the total annualised cost breakdown (i.e., capital cost plus O&M) in 2030, under various end-system configuration within the "PV+" scenario. WT and BESS reach cost parity by 2030, if WT hold a RES share ranging between about 32% and 36%, depending on the evolution of the BESS cost. Overall, the pathway's average annualised cost increase for every additional 1% RES share in the "PV+" scenario is equal to 27-33 million €, and the total budget spent until 2030 is equal to 4.7-5 billion €.

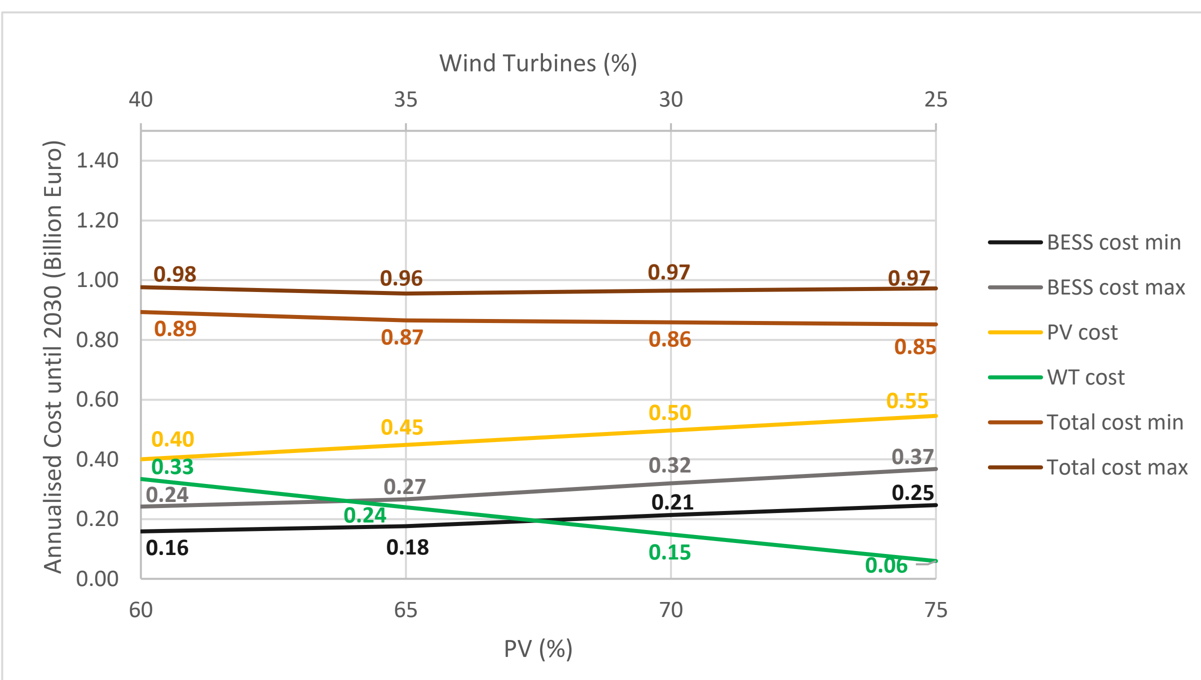

Fig. 9. "PV+" scenario investment cost breakdown until 2030

Finally, it is important to note that when multiple pathways towards the desired end-system configuration exist, the choice of pathway might affect the pace of RES integration in the electricity mix, or the timing and quantity of BESS capacity needs. This is graphically, illustrated in Fig. 10 and Fig. 11 which show the evolution of RES shares and BESS capacities, for the marginal pathways of the "PV+ min" and "PV+ intermediate 1" cases (see Fig. 8). The choice of pathway affects both the RES integration percentage and the timing of BESS requirements. Specifically, in the "PV+ min" case (Fig. 10), pathways appear to result in up to 3.4% RES integration difference until the 2030 end-system congifuration, while the timing of BESS capacity requirements initiate up to two years earlier with higher PV shares.

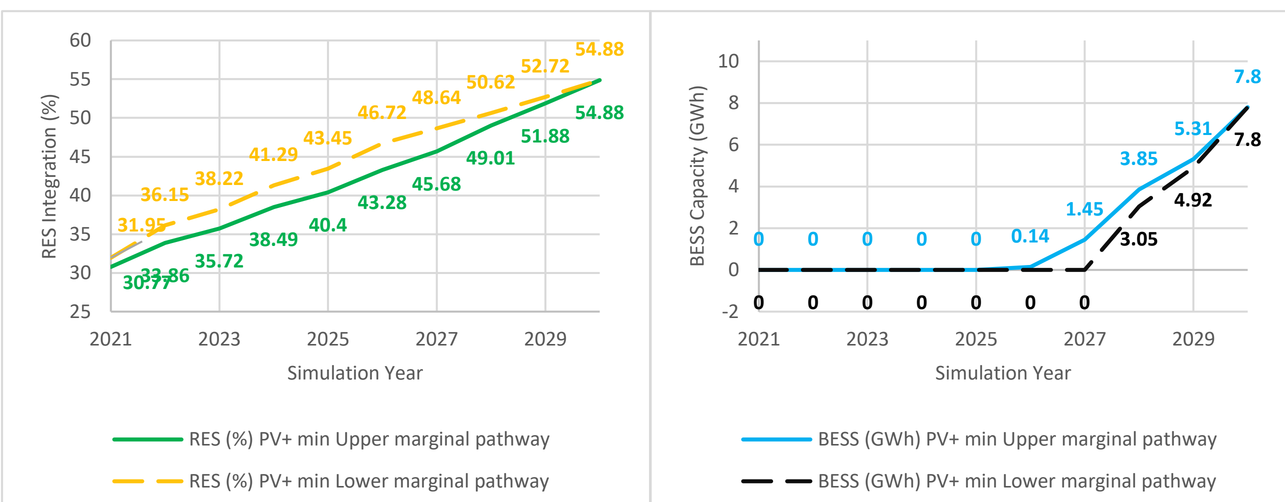

Fig. 10. RES integration and BESS capacity evolution for the marginal pathways of PV+ min case

Also, the effect on both metrics changes as the pathway option space becomes smaller (i.e. "PV+ intermediate" compared to "PV+ min"). Characteristically, as shown in Fig. 11, the maximum difference of RES integration among pathways is lower than 1%, while the timing of BESS capacity requirements remains practically the same among pathways, with small differences in the capacity slope of installed BESS.

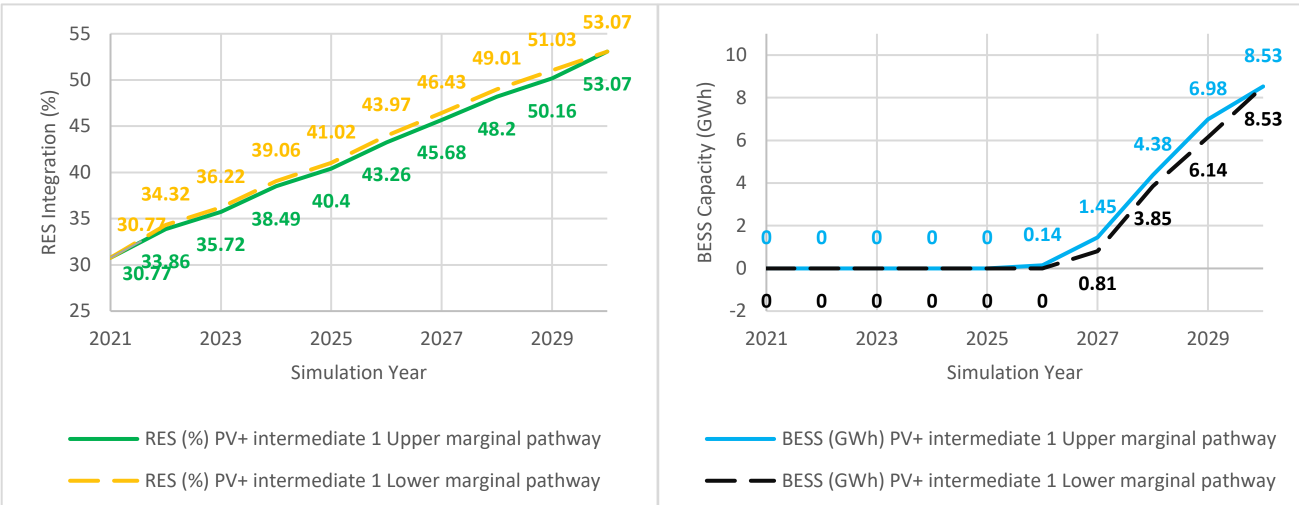

Fig. 11. RES integration and BESS capacity evolution for the marginal pathways of PV+ intermediate 1 case

4.2. *Wind+ Scenario*

The "Wind+" scenario, is the opposite of the "PV+" scenario, with WT being the preponderant technology, and holding 60-75% share with respect to the total RES capacity foreseen for 2030. This corresponds to 8820-11025 MW of WT capacity and 3675-5880 MW of PV capacity.

4.2.1. BESS requirements

In this scenario, curtailment levels without BESS capacity range between 0.24-0.40%, and the RES share in the electricity mix ranges between 61.6-66.3%. The required BESS capacity to reduce curtailment below 0.1% annually ranges between 2.4-6.5 GWh, with respective power capacity equal to 0.59-1.62 GW. The resulting RES share in the electricity mix with the use of BESS increases slightly, reaching to 61.7-66.5%. The correlation of WT share and RES integration in this case implies an increasing rate of +0.32% RES share per 1% additional WT share in the RES mix. Fig. 12 shows a typical day where the BESS operates through the day. Residual demand that needs to be met by thermal units is also observed in this scenario, however, with smoother peaks (i.e., 6.4-7.1GW) and distributed during the morning and afternoon hours, compared to the case with high PV shares.

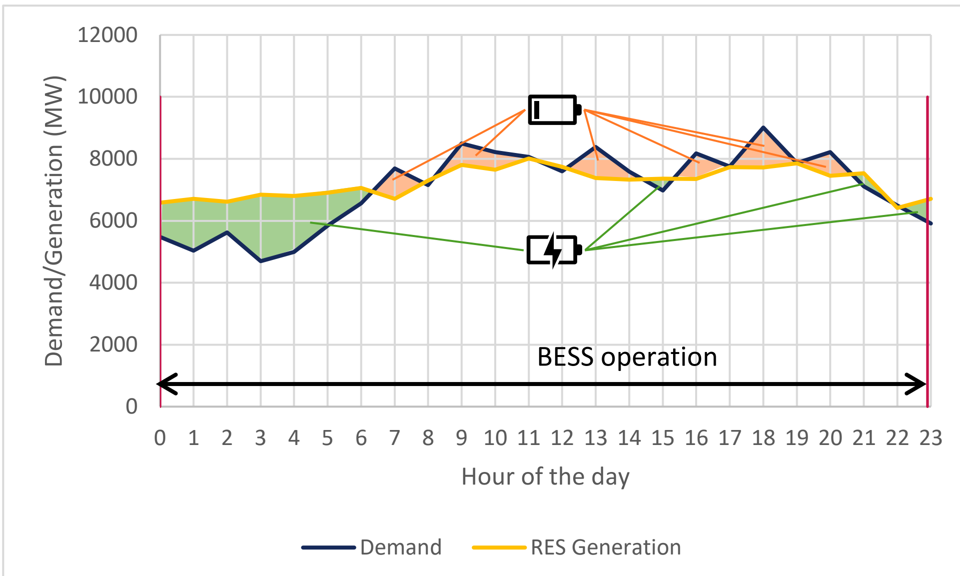

Fig. 12. BESS operation throughout a typical day with high generation in the "Wind+" scenario

4.2.2. How to get there

In the "Wind+" scenario too, there are multiple pathways in order to reach the desired end-system configuration. As shown in Fig. 13, when WT shares in the end-system configuration increase, the pathway options towards their achievement decrease significantly, leaving only one pathway to follow when high WT shares are aimed in 2030 (i.e., "Wind+ intermediate 2" and "Wind+ max" cases). PV can be the preponderant technology in the early years (e.g., upper marginal pathway of the "Wind+ min case"), but new WT installations will need to prevail early enough to avoid capacity lock-ins.

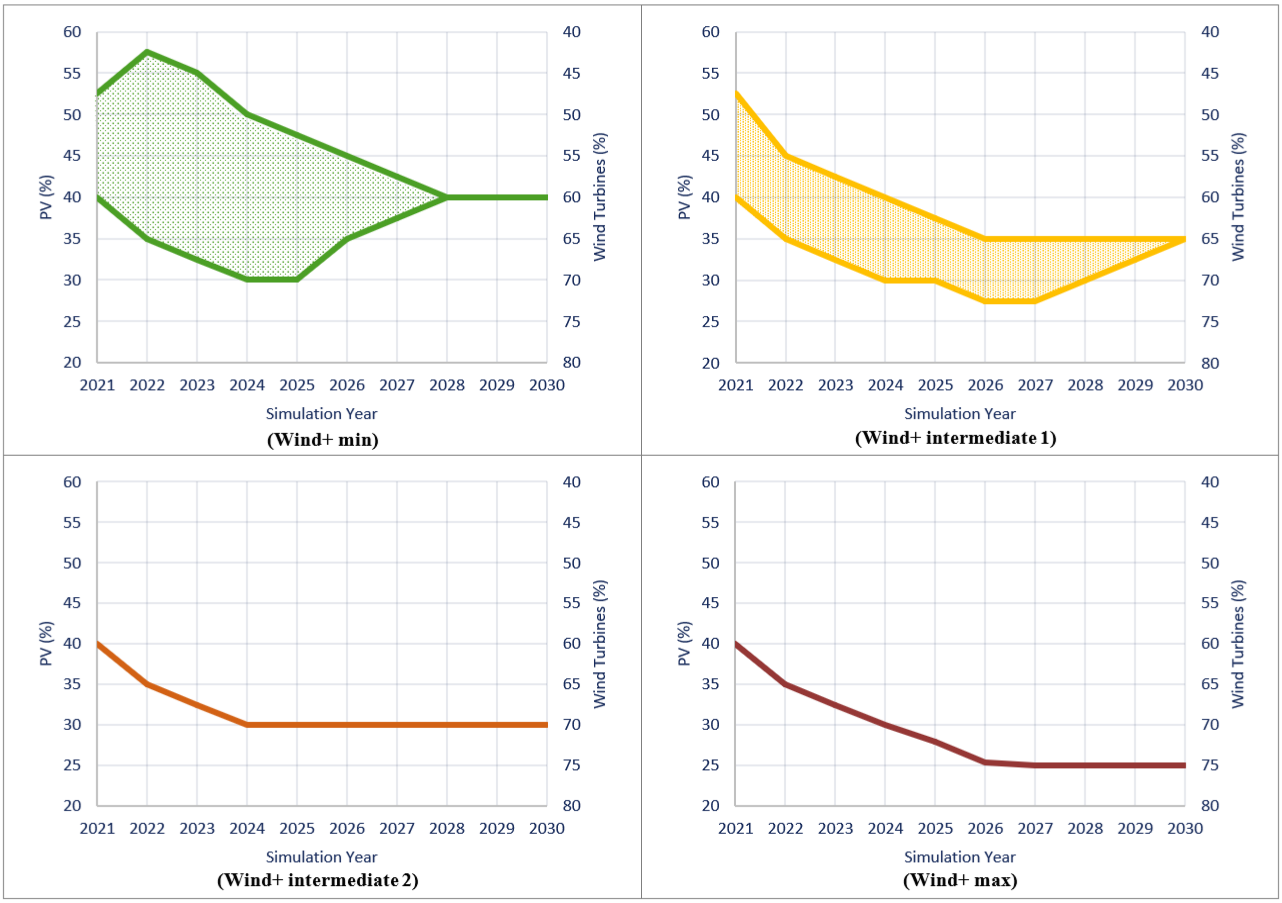

Fig. 13. Pathways towards the Wind+ scenario. **(Wind+ min)**: Configuration in 2030 consisting of 40% PV and 60% WT. **(Wind+ intermediate 1)**: Configuration in 2030 consisting of 35% PV and 65% WT. **(Wind+ intermediate 2)**: Configuration in 2030 consisting of 30% PV and 70% WT. **(Wind+ max):** Configuration in 2030 consisting of 75% PV and 25% WT.

In terms of BESS requirements to minimize curtailment, the average BESS needs per additional RES share range between 0.6-1.8 GWh/%RES. The smaller capacity from the range mentioned in section 4.2.1 (2.4-6.5 GWh) would be required in a configuration with about 62.5% WT. In fact, the results indicate that this configuration requires the minimum BESS capacity of all the scenarios examined. For every additional 1% of WT capacity, on average an additional 330MWh of BESS capacity would be required to ensure low curtailment, while for every additional 1% of PV capacity an additional 260MWh of BESS capacity would be required.

The average annualised cost increase, for every additional 1% RES integration in a "Wind+" system, ranges between 26-28 million €, and the total budget spent until 2030 is equal to 5.8-7.2 billion €. Fig. 14 illustrates the total annualised cost breakdown in 2030, under various end-system configurations within the "Wind+" scenario. The storage costs remain almost stable until the configuration consisting of 65% WT, with the minimum being observed at 62.5% WT. Then, the BESS cost gradually increases, with steeper slopes with higher WT shares. In terms of cost parity, PV and BESS require equal investment plus O&M costs by 2030, if WT hold about 70% and 72.5% of the RES share, depending on the evolution of the BESS cost.

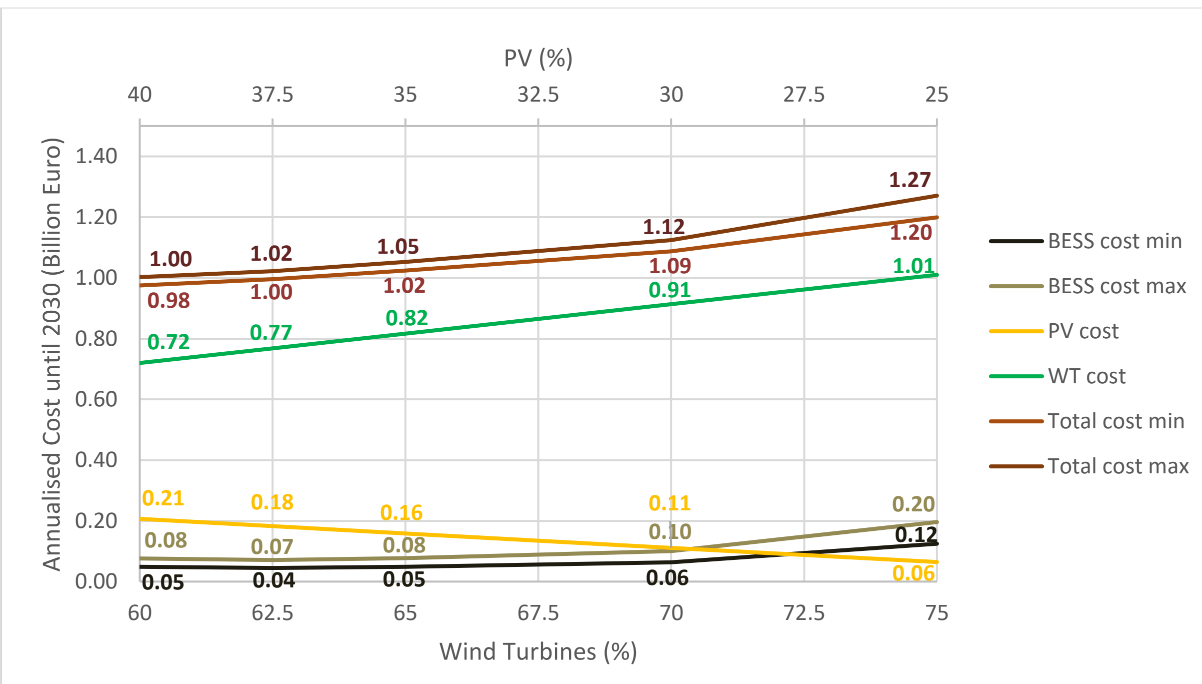

Fig. 14. "Wind+" scenario investment cost breakdown until 2030

Finally, for the "Wind+ min" and "Wind+ intermediate 1" cases, for which multiple pathways towards the end-system configuration exist, the choice of pathway affects the pace of RES integration, and the timing and quantity of BESS capacity needs (Fig. 15 and Fig. 16). The effect on RES integration is more evident in the "Wind+ min" case, compared to the "Wind+ intermediate 1 case", due to the wider pathway space available towards the end-system configuration (see Fig. 13). In fact, as shown in Fig. 15 pathways appear to result in up to 4.3% RES integration difference, until 2028 where all pathways lead to the same configuration.

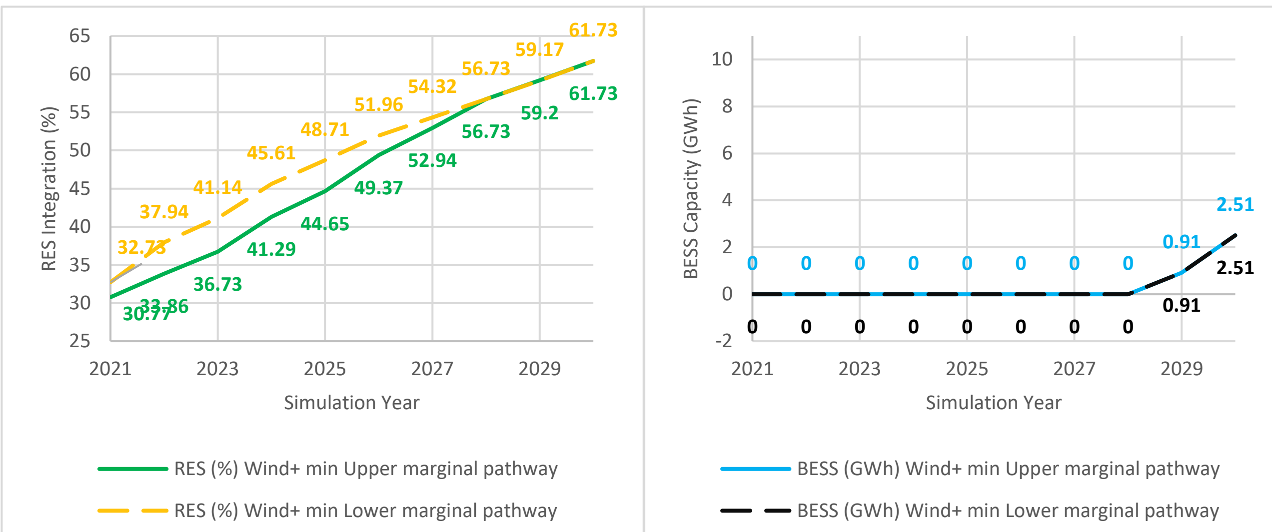

Fig. 15. RES integration and BESS capacity evolution for the marginal pathways of "Wind+ min" case

Contrary, the effect on the timing and quantity of BESS capacity needs is evident only in the "Wind+ intermediate 1" case (Fig. 16) where, BESS capacity requirements start to appear one year earlier, depending on the choice of pathway. This is because the lower pathways of the "Wind+ intermediate 1" case feature a relatively high WT share in 2029 (up to 67.5%), which leads to the need for BESS capacity to minimize curtailment.

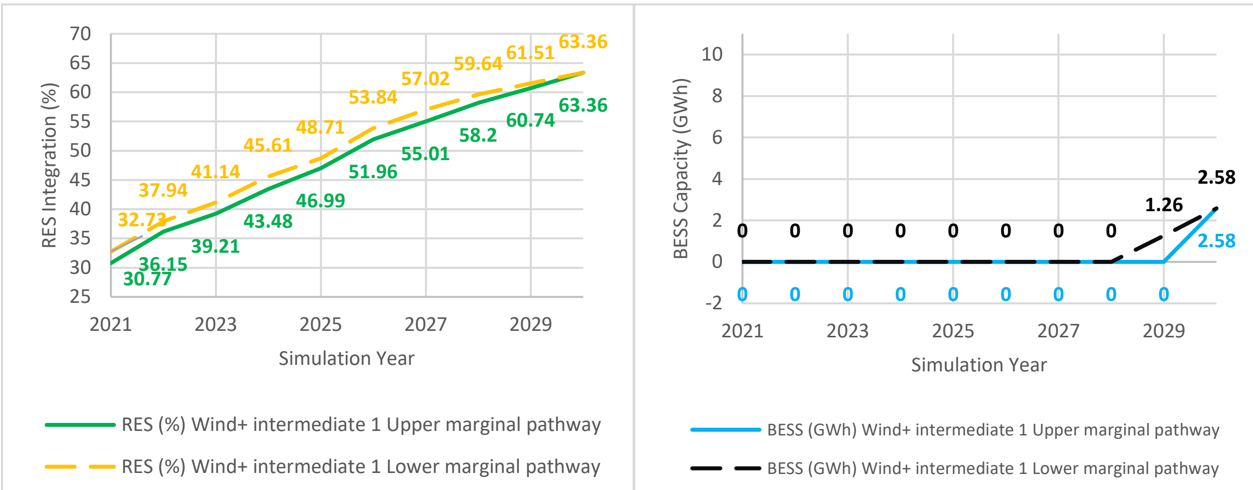

Fig. 16. RES integration and BESS capacity evolution for the marginal pathways of Wind+ intermediate 1 case

4.3. *Balanced scenario*

The "Balanced" scenario is an intermediate situation between the "PV+" and "Wind+" scenarios. PV and WT hold 42.5-57.5% share with respect to the total RES capacity foreseen for 2030. This corresponds to 6247.5-8452.5 MW of installed capacity for each technology, with each configuration summing up to a total of 14700MW of RES capacity.

4.3.1. BESS requirements

In this scenario, curtailment levels without BESS capacity range between 0.36-0.85%, and the RES share in the electricity mix ranges between 55.4-60.8%. In order to reduce curtailment levels below 0.1%, the required BESS capacity ranges between 3.0-6.4 GWh, with respective power capacity ranging in the interval 0.75-1.60 GW. The resulting RES share in the electricity mix increases to 55.8-60.9%, justified by the contribution of BESS to the combined generation profile of PV and WT, which is graphically illustrated in Fig. 17. The correlation of WT/PV share and RES integration in this case indicates a rate of +0.34% (-0.34%) RES share per 1% additional WT (PV) share respectively. In terms of residual demand, in such a configuration, there is uncertainty regarding the frequency and magnitude of generation and demand matching during the off-peak hours, which could make the operation planning of thermal units a challenging and costly task, considering also limitations imposed by their technical specifications (e.g., minimum uptimes, downtimes, start-up times and costs etc.). The peak residual demand events observed in this scenario range between 7.2-7.7GW.

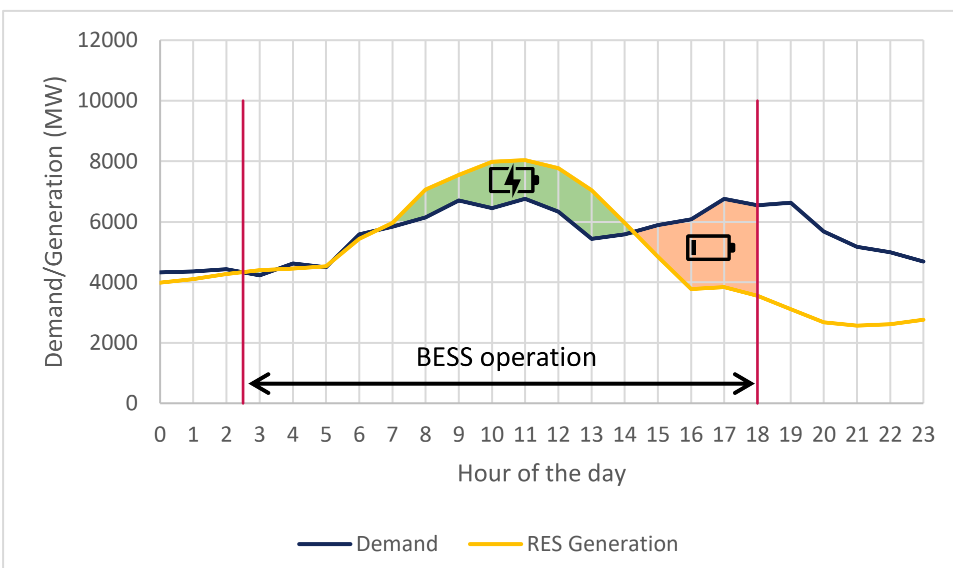

Fig. 17. BESS operation throughout a typical day with high generation in the balanced scenario

4.3.2. How to get there

This scenario features the highest flexibility in terms of pathways towards the end-system configuration, as shown in Fig. 18. This is due to the fact that the installed RES capacity in 2020 features 54.7% WT (3153 MW) and 45.3% PV (2606 MW), and a not very dissimilar percentage is aimed until 2030. Therefore, all pathways towards the 2030 configuration can feature either PV or WT as the preponderant technology for several years, until the end-system PV-to-WT configuration is achieved.

Among the cases presented in Fig. 18, the "Balanced+Wind" and the "Balanced Equal" have the greatest flexibility, due to the initial conditions in 2020 which feature WT as the preponderant technology.

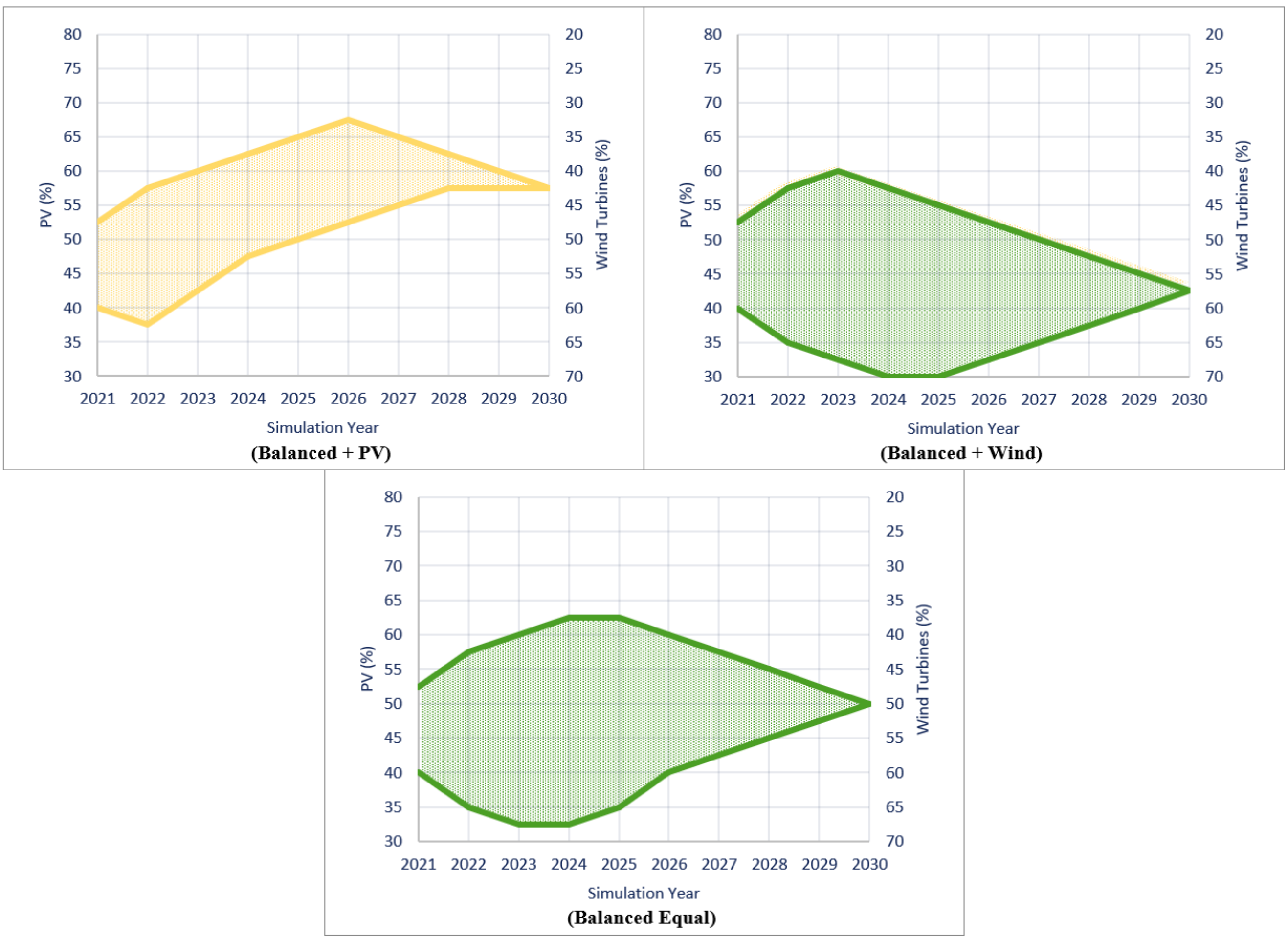

Fig. 18. Pathways towards the Balanced scenario. **(Balanced+PV):** Configuration in 2030 consisting of 57.5% PV and 42.5% WT. **(Balanced+Wind):** Configuration in 2030 consisting of 42.5% PV and 57.5% WT. **(Balanced Equal):** Configuration in 2030 consisting of 50% PV and 50% WT.

Regarding BESS requirements, the average BESS needs per additional RES share range between 0.9-1 GWh/%RES. However, randomness can be observed in the required BESS capacity with changing PV/WT shares, indicating the effect of combined intermittency of the two technologies. The average annualised cost increase for every additional 1% of RES integration in a "Balanced" system in 2030 ranges between 26-31 million €, and the total budget spent until 2030 is equal to 4.8-5.7 billion €. The total annualised cost breakdown in 2030, under various end-system configurations in 2030 within the "Balanced" scenario is shown in Fig. 19. In general, the cost of WT is the higher above an about 42.5% WT share. The BESS cost is lower than that of both generating technologies, regardless of the end-system configuration.

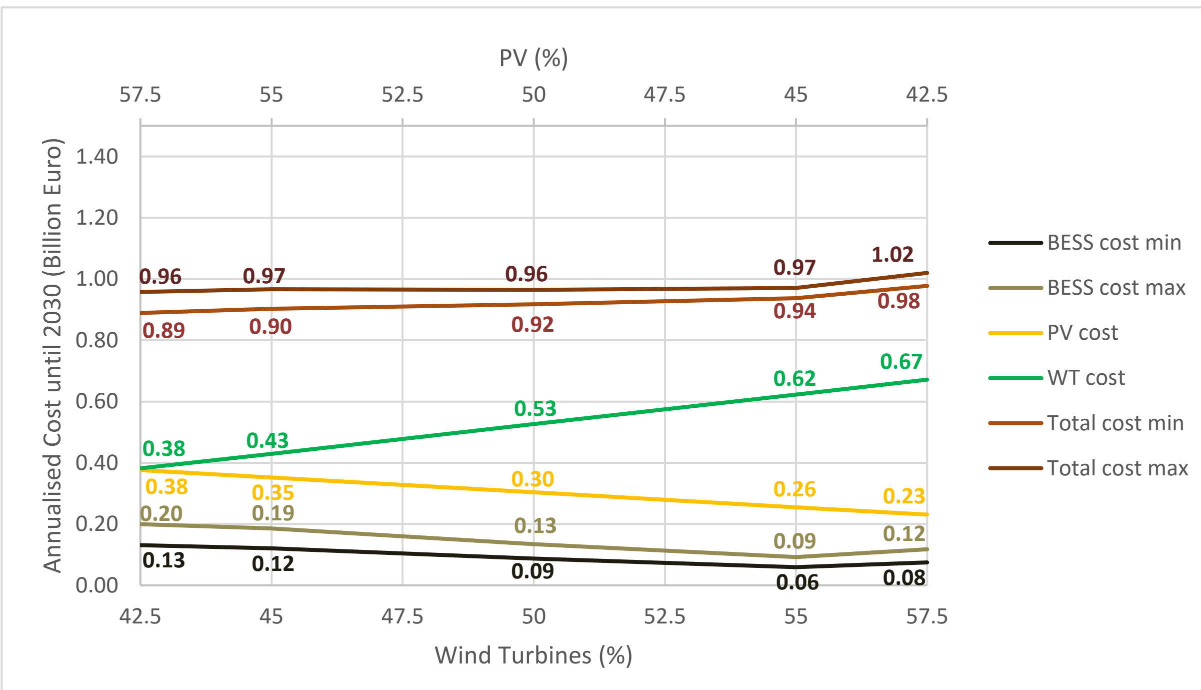

Fig. 19. "Balanced" scenario investment cost breakdown until 2030

Finally, like in the "PV+" and "Wind+" scenarios, the choice of pathway affects the pace of RES integration in the electricity mix, and the timing and quantity of BESS capacity needs. In the "Balanced+PV" case, the choice of pathway significantly affects the RES integration levels, and slightly the timing and quantity of BESS capacity needs (Fig. 20). Specifically, pathways appear to result in up to 4.1% RES integration difference until 2030. As for the BESS capacity requirements, their timing can differ up to one year, starting from 2026 or 2027, and the capacity deviation among pathways can be up to 800 MWh.

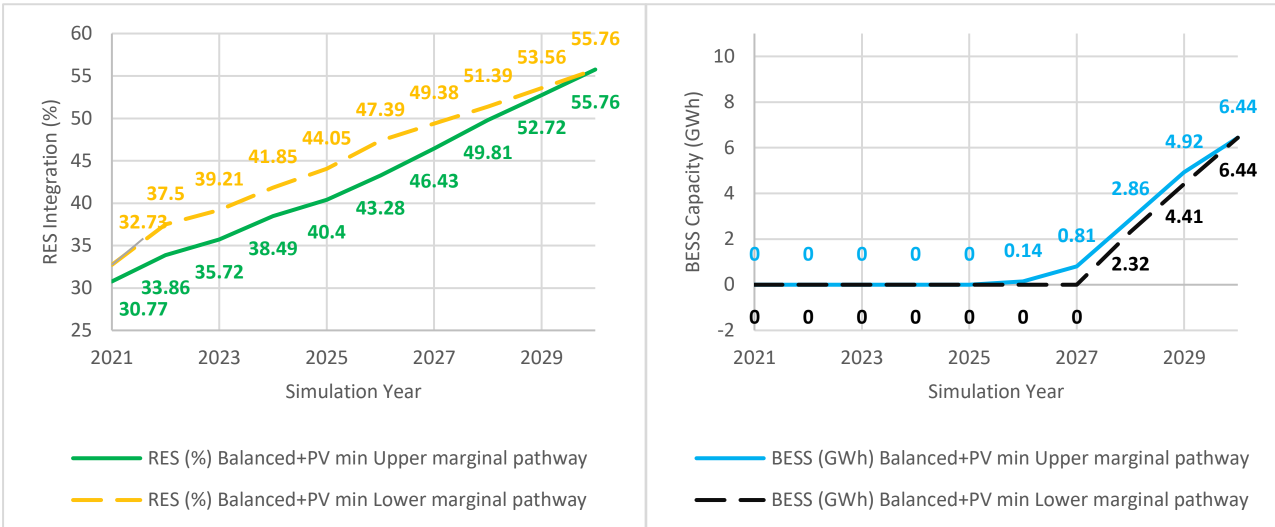

Fig. 20. RES integration and BESS capacity evolution for the marginal pathways of "Balanced+PV" case

In the "Balanced+Wind" case, the choice of pathway affects significantly mainly the RES integration levels, with barely noticeable effect on the timing and quantity of BESS capacity needs. As shown in Fig. 21, the RES integration difference among pathways can be up to 6% until the 2030 end-system configuration. The timing of BESS capacity requirements can differ up to one year, starting in 2028 or 2029, but the BESS capacity difference among pathways is minimal.

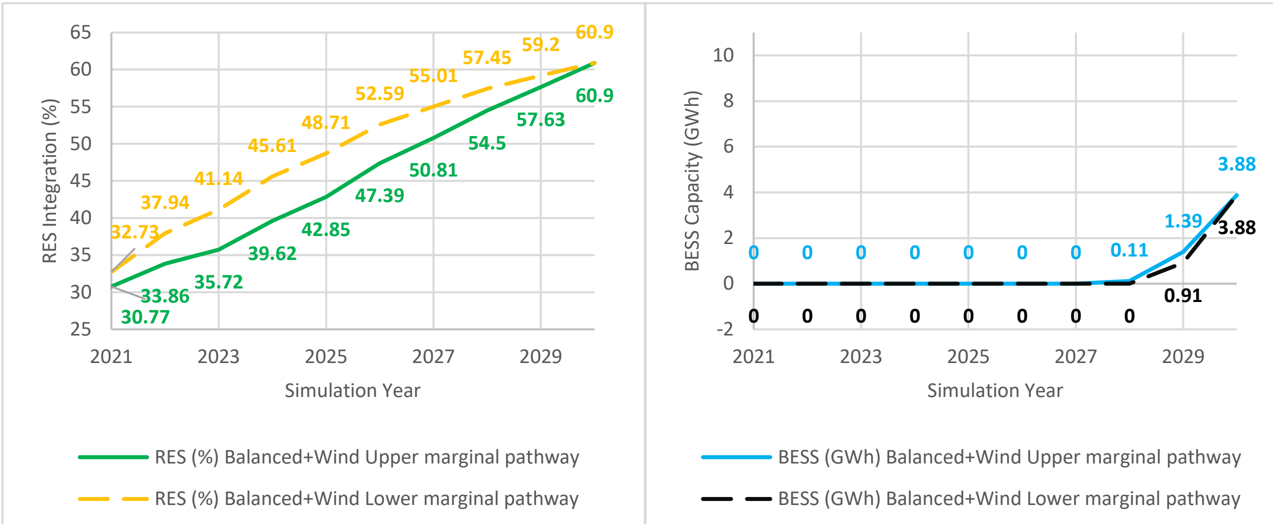

Fig. 21. RES integration and BESS capacity evolution for the marginal pathways of "Balanced+Wind" case

Finally, for the "Balanced Equal" case, the effect of pathway choice is evident mainly in the RES integration levels. Specifically, as shown in Fig. 22, the RES integration difference among pathways can be up to 6.6% until the 2030 end-system configuration, while the timing (starting in 2028) and quantity of BESS requirements is almost the same among the pathways.

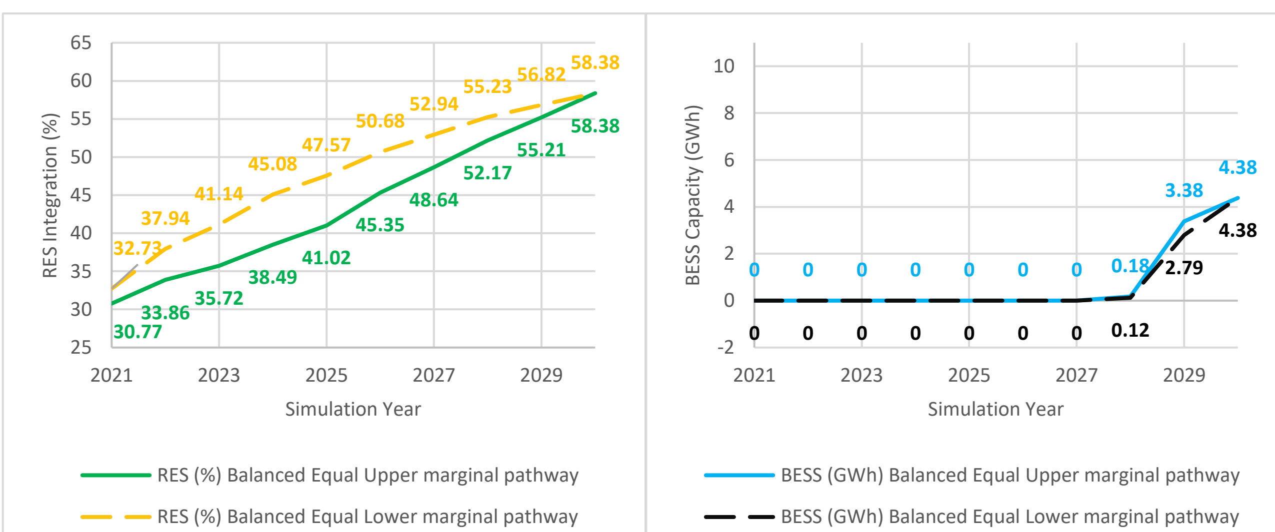

Fig. 22. RES integration and BESS capacity evolution for the marginal pathways of "Balanced Equal" case

5. Discussion

From the results presented in the previous section, it becomes apparent that the various end system configurations for 2030 can have significant impact on key performance metrics, such as RES integration level, optimal technology mix minimizing storage, or costs, as well as on the pathway flexibility towards their achievement. Minimum BESS configurations do not necessarily result in minimum costs, while minimum cost pathways seem to fail to meet the required RES integration levels in Greece. Table 5 presents a comparative summary of the key findings.

Table 5
Key performance metrics and requirements for the materialization of the examined scenarios

Scenario	PV+	Balanced	Wind+
Pathways Availability towards 2030 (Flexibility)	+	+++	++
BESS Capacity in 2030 (GWh)	7.6-11.7	3.0-6.4	2.4-6.5
BESS capacity per additional % RES (GWh)	1.1-1.3	0.9-1.0	0.6-1.8
Timing of BESS capacity requirements (year)	2026-2028	2026-2029	2029-2030
RES Share in 2030 (%)	49.3-54.9	55.8-60.9	61.7-66.5
Residual Peak Demand (GW) – Probable occurrence	7.6-8.1 – night	7.2-7.7 – entire day	6.4-7.1 – morning
Annualised cost increase per additional 1% RES (M€)	27-33	26-31	26-28
Annualised costs in 2030 (B€)	0.85-0.98	0.89-1.02	0.98-1.27
Total budget spent until 2030 (B€)	4.7-5.0	4.8-5.7	5.8-7.2

A key takeaway is that the end system configurations featuring high PV shares, are less flexible in terms of pathways for their realization. This is because the installed capacity in 2020 is equal to 3153MW of WT and 2606MW of PV, which correspond to a RES portfolio consisting of 54.7% WT and 45.3% PV. The preponderance of WT in 2020 gives a flexibility to configurations featuring medium-to-high WT shares in 2030 to be achieved with a wide range of pathways. This in turn indicates that the selection of a 2030 end-system configuration needs to be made with long term planning in mind (e.g., 2050), as it will affect the pathways' availability towards long-term targets.

In terms of curtailment and required BESS to minimize it, in principle, both increase with greater preponderance of PV in the electricity mix, which is indicated by the almost double storage volume required in 2030 with relevance to the balanced and Wind-dominated scenarios. This can be attributed to the seasonal complementarity of WT and PV generation, which approaches better the seasonal demand profile in Greece with greater WT preponderance as shown in Fig. 23 for 2030.

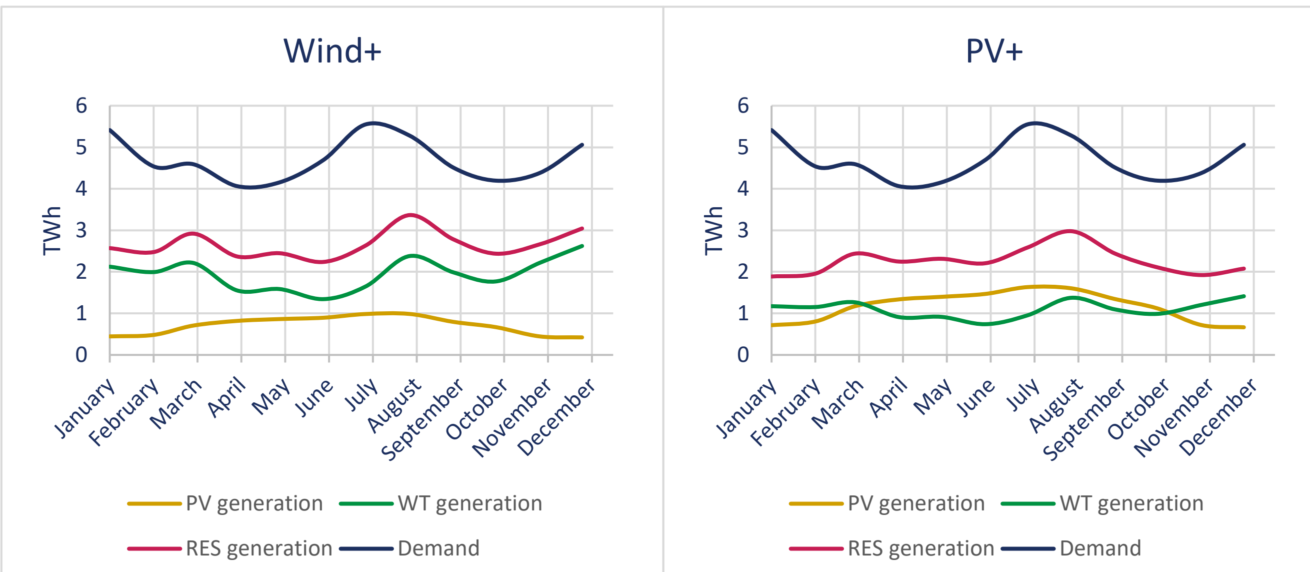

Fig. 23. Seasonal demand and RES generation profiles for 2030

This is in line with the results of other studies, who mention that the total storage size is significantly higher in solar dominated systems than in wind dominated systems (Cebulla et al., 2018; Nayak-Luke et al., 2021), with storage capacity and power requirements increasing with high solar penetration levels (Fattori et al., 2017). Consequently, also the timing of BESS capacity requirements occurs sooner in PV-dominated than in Wind-dominated systems.

An optimal combination of WT and PV is observed at capacities 62.5% and 37.5% respectively, requiring minimum BESS capacity to manage curtailment. This configuration is in line with the results of Komušanac et. al. (2016) who reported that minimum critical excess electricity production is achieved with higher WT capacity than PV capacity, and is within the range mentioned by Weitemeyer et. al. (2015) who found that optimal integration of RES share above 30% is achieved with a wind share ranging between 50-65%. Yet, beyond that minimum-BESS point and towards higher WT shares, BESS requirements start to increase rapidly. This is demonstrated by the high upper limit of BESS capacity requirements per additional percentage of RES integration (Table 5), compared to the other two scenarios.

The RES integration potential of each end-system configuration is also worth examining. Higher WT shares achieve higher RES shares in the electricity mix, which is expected taking into account the higher capacity factors of WT. What is interesting to highlight is the magnitude of residual demand as well as its timing. PV-dominated systems appear to contribute to covering demand during morning hours, with significant peak events of residual demand occurring at night. On the contrary, WT-dominated systems cover the largest part of the demand during night hours, with the peak residual demand events occurring at morning hours, but with lower magnitude. In any case, both systems appear to have a predictable pattern for residual demand instances that would need to be covered by thermal units. This is something that balanced systems lack of, since residual demand events may happen anytime, making the unit commitment problem of thermal units a challenging and potentially expensive task, if peaking units need to be dispatched frequently.

Finally, regarding the cost of the pathways, the results indicate that BESS is not the key cost component until 2030 due to the relatively low storage capacity required, in comparison to the planned generation capacity. In general, WT-dominated systems are expected to be more expensive than PV-dominated systems, driven by the higher investment cost of WT compared to the cost of PV. Nevertheless, the total cost alone is not a decisive parameter. When compared to what is achieved with the money spent, it is evident that WT-dominated systems, which also require less storage compared to PV-dominated systems, perform better in terms of RES integration due to their higher capacity factor, with balanced systems achieving intermediate results. This is easily deductible by comparing the annualised cost increase per additional 1% RES of Table 5.

6. Conclusions and policy implications

In this paper, RES plus storage capacity configuration pathways towards utilization maximization of domestically produced RES-generated electricity with low curtailment in the Greek electricity system until 2030 have been investigated. The RES technologies considered are PV and WT, which are core technologies mentioned in the Greek NECP. The storage technology accounted for in this study to support the integration of RES is utility-scale Li-Ion BESS, operating in parallel with the installed capacity of PHS in Greece. The main endeavors of this article is to highlight what are the plausible PV, WT and BESS capacity configurations in 2030 with respect to the RES capacity targets mentioned in the Greek NECP, and what capacity configuration pathways can be followed towards their achievement, presenting the outcomes of each option.

To enable this, a modelling framework which treats policies as experiments and enables adaptive policy design based on dynamic information and experience acquired through simulated policy implementation, has been used. Such an experimental policy analysis method has been proposed almost a century ago by Dewey (Dewey, 1927), and is most relevant today considering the uncertainties and complexities encountered during the transformation of the electricity system from its dispatchable fossil-fueled regime to a RES-based intermittent one. The modeling framework consists of the STREEM and the AIM models. STREEM using its functionality to simulate in high temporal resolution the operation of storage technologies, enables the exploration of storage capacity requirements of a region, towards user defined curtailment levels. The main features of STREEM lie in its ability to model various storage technologies with simple parameterization of its input variables, as well as its capability of approximating the actual curve of storage/curtailment correlation, regardless of the storage technology modelled, achieving that way efficient computational performance. AIM on the other hand is a plug-in model, which using the inputs and outputs of simulation models visualizes adaptive policy maps, indicating alternative pathways which lead to desired policy outcomes. Main features of AIM lie in its intuitive simulated policy implementation functionality, and its ability to enable the assessment of a large number of policy development scenarios with only few simulations performed by a simulation model. Overall, the linking of the two models enable detailed exploration of RES plus storage transitions of electricity systems, considering specified technologies and actual timelines. Although in this paper the modelling framework is applied to the case of Greece, it is capable of modelling any other country or region, given that the required data is available.

For the Greek case under study, the various PV, WT and BESS configurations are considered as policy options, and their stepwise implementation (changing configurations) are the pathways towards the achievement of targeted end-system configurations. From the overall analysis, it was found that the achievement of the Greek RES integration targets until 2030 (61% in gross electricity consumption) depends highly on the end-system configuration. Specifically, marginal achievement is feasible with a configuration with about 42.5% PV and 57.5% WT with respect to the total RES capacity (14700MW) and 3.9 GWh of accompanying BESS capacity. Such shares are close to the current Greek RES mix (mid 2021), which consists of 55.1% WT (3755 MW) and 44.9% PV (3055 MW). Considering that on average with every additional 1% of WT in the electricity mix 0.34% additional RES integration share is achieved, and vice versa, the PV and WT shares mentioned in the Greek NECP (i.e., 52.4% PV and 47.6% WT) are expected to achieve about 92% of the Greek RES integration target. The remaining contribution would need to be provided either **(i)** by other RES technologies (e.g., biofuels, solar thermal, geothermal, etc.) or **(ii)** with configurations featuring higher WT shares, or **(iii)** with higher total RES capacity in order to reach the pledged RES integration levels.

BESS capacity is an important parameter to consider when deciding on specific PV and WT shares. Efficient RES integration with minimum BESS requirements could be achieved in a configuration with about 62.5% WT, 37.5% PV and 2.4 GWh of accompanying BESS capacity. Beyond that minimum, the sensitivity of BESS requirements is equal to 330MWh for each additional 1% WT share, and 260MWh for each additional 1% PV share. Such sensitivity is crucial when planning future capacity configurations, especially when presented with reference to RES integration levels, equal to 1.1-1.3 GWh/%RES in PV dominated systems, 0.6-1.8 GWh/%RES in wind dominated systems and 0.9-1 GWh/%RES in systems with balanced PV and WT shares. Considering this, the tendering procedure should be designed in a way that accounts for accompanying BESS capacity that would enable the optimal integration of the chosen RES configuration.

Investment plus O&M costs are also a crucial parameter for policymakers when deciding on PV, WT and BESS configurations. Until 2030, the cost intensity in Greece is mostly accounted to WT, followed by PV and then by BESS. However, given the weighted contribution of each technology in the plausible RES plus storage configurations, with similar amounts of investments, alternative configurations with PV or WT as the preponderant technology, or balanced configurations can be achieved. Specifically, considering that the average annualised cost increase for every additional 1% of RES is about 27-33 million € for PV dominated systems, 26-28 million € for wind dominated systems and 26-31 million € for balanced systems, the higher unit-costs of specific technologies, can be counterbalanced with appropriate combinations of technological investments. Opportunities for funding should also be considered, in order to leverage available funding for applicable technologies. Indicatively, the Greek recovery and sustainability plan (IEA, 2022) provides 450 million € for the installation of electricity storage systems. This implies that slightly wind-oriented systems, which require the lowest levels of

BESS, can at a high degree be materialized by exploiting the available funding for storage technologies, while for systems with high preponderance of PV or WT, the available funding for storage can be exceeded.

Lastly, the timing of investments is a major factor affecting the success of planned configurations. When targeting for electricity system buildouts with high preponderance of one technology, investments in this technology should be prioritized early enough to avoid capacity lock-ins. The pathway of RES investments in turn affects the timing of BESS capacity requirements, which could also affect the pathways' cost based on projected technological cost reductions. Reportedly, with high PV shares, BESS in Greece would be needed when RES integration exceeds 41-48%, with high WT shares when RES integration exceeds 59-64%, and with balanced WT and PV shares, when RES integration exceeds 51-58%, depending on the installed PV and WT shares. Timewise, such integration levels could be expected in Greece in the period 2026-2029, implying that plans for BESS investment should be made for the second half of the NECP horizon.

Overall, this study's general conclusions are summarised as follows:

- WT-dominated systems are suitable for applications where ambitious renewable targets need to be reached with PV and WT as the main technologies, daytime demand peaks are moderate, or the solar potential is limited. The high (yet efficient) investment cost and the long licensing procedures of WT are the main challenges of such systems.
- PV-dominated systems could be an option when the wind potential is limited. Yet, such systems are less efficient in terms of output (i.e., %RES integration) per money spent and would require early and high investments in storage.

- Balanced systems are suitable option if long-term policy planning is not available and options towards future system buildout options need to remain open. These systems combine merits and drawbacks from both PV- and WT- dominated systems.

Acknowledgements

This paper is based on research conducted within the EC funded Horizon 2020 Framework Programme for Research and Innovation (EU H2020) Project titled "Sustainable Energy Transitions Laboratory" (SENTINEL) - Grant Agreement No. 837089. The authors would like to acknowledge the support from the EC. The authors would also like to acknowledge the contribution of the Public Power Corporation of Greece (PPC) to the validation of simulation data. The content of the paper is the sole responsibility of its authors and does not necessary reflect the views of the EC or the PPC.

References

Angelopoulos, D., Doukas, H., Psarras, J., Stamtsis, G., 2017. Risk-based analysis and policy implications for renewable energy investments in Greece. Energy Policy 105, 512–523. https://doi.org/10.1016/J.ENPOL.2017.02.048

Antweiler, W., 2021. Microeconomic models of electricity storage: Price Forecasting, arbitrage limits, curtailment insurance, and transmission line utilization. Energy Econ. 101, 105390. https://doi.org/10.1016/J.ENECO.2021.105390

Aposporis, H., 2022. Greek government adopts stricter rules for renewables connection [WWW Document]. Balk. Green Energy News. URL https://balkangreenenergynews.com/greek-government-adopts-stricter-rules-for-connecting-renewables-to-grid/ (accessed 1.9.23).

Breyer, C., Khalili, S., Bogdanov, D., Ram, M., Oyewo, A.S., Aghahosseini, A., Gulagi, A., Solomon, A.A., Keiner, D., Lopez, G., Ostergaard, P.A., Lund, H., Mathiesen, B. V., Jacobson, M.Z., Victoria, M., Teske, S., Pregger, T., Fthenakis, V., Raugei, M., Holttinen, H., Bardi, U., Hoekstra, A., Sovacool, B.K., 2022. On the History and Future of 100% Renewable Energy Systems Research. IEEE Access 10, 78176–78218. https://doi.org/10.1109/ACCESS.2022.3193402

Budischak, C., Sewell, D., Thomson, H., MacH, L., Veron, D.E., Kempton, W., 2013. Cost-minimized combinations of wind power, solar power and electrochemical storage, powering the grid up to 99.9% of the time. J. Power Sources 225, 60–74. https://doi.org/10.1016/J.JPOWSOUR.2012.09.054

Buonomano, A., Calise, F., d'Accadia, M.D., Vicidomini, M., 2018. A hybrid renewable system based on wind and solar energy coupled with an electrical storage: Dynamic simulation and economic assessment. Energy 155, 174–189. https://doi.org/10.1016/J.ENERGY.2018.05.006

Cebulla, F., Haas, J., Eichman, J., Nowak, W., Mancarella, P., 2018. How much electrical energy storage do we need? A synthesis for the U.S., Europe, and Germany. J. Clean. Prod. 181, 449–459. https://doi.org/10.1016/J.JCLEPRO.2018.01.144

Chang, Y., Phoumin, H., 2021. Curtailed electricity and hydrogen in Association of Southeast Asian Nations and East Asia Summit: Perspectives form an economic and environmental analysis. Int. J. Hydrogen Energy. https://doi.org/10.1016/J.IJHYDENE.2021.10.194

Christoph Soini, M., Parra, D., Kumar Patel, M., 2019. Does bulk electricity storage assist wind and solar in replacing dispatchable power production? Energy Econ. 85, 104495. https://doi.org/10.1016/j.eneco.2019.104495

Cole, W., Frazier, A.W., Augustine, C., 2021. Cost Projections for Utility-Scale Battery Storage: 2021 Update.

Denholm, P., 2015. The role of storage and demand response.

Denholm, P., Nunemaker, J., Gagnon, P., Cole, W., 2020. The potential for battery energy storage to provide peaking capacity in the United States. Renew. Energy 151, 1269–1277. https://doi.org/10.1016/j.renene.2019.11.117

Dewey, J., 1927. The Public and Its Problems. Holt and Company, New York.

EIA, 2020. Utility-scale battery storage costs decreased nearly 70% between 2015 and 2018 [WWW Document]. U.S. Energy Inf. Adm. URL https://www.eia.gov/todayinenergy/detail.php?id=45596 (accessed 10.18.22).

ENTSO-e Transparency Platform, 2021. ENTSO-e Transparency Platform [WWW Document]. URL https://transparency.entsoe.eu/ (accessed 3.27.20).

European Commission, 2022. REPowerEU Plan. https://ec.europa.eu/commission/presscorner/detail/en/IP_22_3131.

European Commission, 2019. The European Green Deal. Eur. Comm. https://doi.org/10.1017/CBO9781107415324.004

European Parliament and the Council, 2019. Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity. Off. J. Eur. Union.

Fattori, F., Anglani, N., Staffell, I., Pfenninger, S., 2017. High solar photovoltaic penetration in the absence of substantial wind capacity: Storage requirements and effects on capacity adequacy. Energy 137, 193–208. https://doi.org/10.1016/J.ENERGY.2017.07.007

Gao, X., Rai, V., Nemet, G.F., 2022. The roles of learning mechanisms in services: Evidence from US residential solar installations. Energy Policy 167, 113003. https://doi.org/10.1016/J.ENPOL.2022.113003

Gaspar, I., Castro, R., Sousa, T., 2021. Optimisation and economic feasibility of Battery Energy Storage Systems in electricity markets: The Iberian market case study. J. Clean. Prod. 324, 129255. https://doi.org/10.1016/J.JCLEPRO.2021.129255

Goteti, N.S., Hittinger, E., Williams, E., 2019. How much wind and solar are needed to realize emissions benefits from storage? Energy Syst. 10, 437–459. https://doi.org/10.1007/S12667-017-0266-4/FIGURES/12

Greek Ministry of Environment and Energy, 2019a. Greek National Energy and Climate Plan. J. Greek Gov. B’ 4893.

Greek Ministry of Environment and Energy, 2019b. Long-term Strategy for Energy and Climate.

Hannan, M.A., Wali, S.B., Ker, P.J., Rahman, M.S.A., Mansor, M., Ramachandaramurthy, V.K., Muttaqi, K.M., Mahlia, T.M.I., Dong, Z.Y., 2021. Battery energy-storage system: A review of technologies, optimization objectives, constraints, approaches, and outstanding issues. J. Energy Storage 42, 103023. https://doi.org/10.1016/J.EST.2021.103023

Hansen, K., Breyer, C., Lund, H., 2019. Status and perspectives on 100% renewable energy systems. Energy 175, 471–480. https://doi.org/10.1016/J.ENERGY.2019.03.092

Heide, D., von Bremen, L., Greiner, M., Hoffmann, C., Speckmann, M., Bofinger, S., 2010. Seasonal optimal mix of wind and solar power in a future, highly renewable Europe. Renew. Energy 35, 2483–2489. https://doi.org/10.1016/J.RENENE.2010.03.012

HOMER Energy, 2020. Battery Roundtrip Efficiency [WWW Document]. URL https://www.homerenergy.com/products/pro/docs/latest/battery_roundtrip_efficiency.html (accessed 5.9.20).

IEA, 2022. National recovery and sustainability plan / Green transition / Power up [WWW Document]. URL https://www.iea.org/policies/12875-national-recovery-and-sustainability-plan-green-transition-power-up?country=Greece&page=2&qs=Gree&year=asc , https://ypen.gov.gr/al-sdoukou-paketo-25-ekat-evro-gia-tis-energeiakes-koinotites-tis-dytikis-makedonias-entos-tou-2021/ (accessed 1.25.22).

IRENA, 2019. Innovation landscape brief: Utility-scale batteries, International Renewable Energy Agency. Abu Dhabi.

Johlas, H., Witherby, S., Doyle, J.R., 2020. Storage requirements for high grid penetration of wind and solar power for the

MISO region of North America: A case study. Renew. Energy 146, 1315–1324. https://doi.org/10.1016/J.RENENE.2019.07.043

Jorgenson, J., Denholm, P., Mai, T., 2018. Analyzing storage for wind integration in a transmission-constrained power system. Appl. Energy 228, 122–129. https://doi.org/10.1016/J.APENERGY.2018.06.046

Kaldellis, J.K., 2015. Photovoltaic-Energy Storage Systems for Remote Small Islands. Sol. Energy Storage 291–326. https://doi.org/10.1016/B978-0-12-409540-3.00013-X

Kalkbrenner, B.J., 2019. Residential vs. community battery storage systems – Consumer preferences in Germany. Energy Policy 129, 1355–1363. https://doi.org/10.1016/J.ENPOL.2019.03.041

Killer, M., Farrokhseresht, M., Paterakis, N.G., 2020. Implementation of large-scale Li-ion battery energy storage systems within the EMEA region. Appl. Energy 260, 114166. https://doi.org/10.1016/j.apenergy.2019.114166

Kleanthis, N., Stavrakas, V., Ceglarz, A., Süsser, D., Schibline, A., Lilliestam, J., Flamos, A., 2022. Eliciting knowledge from stakeholders to identify critical issues of the transition to climate neutrality in Greece, the Nordic Region, and the European Union. Energy Res. Soc. Sci. 93, 102836. https://doi.org/10.1016/J.ERSS.2022.102836

Komušanac, I., Ćosić, B., Duić, N., 2016. Impact of high penetration of wind and solar PV generation on the country power system load: The case study of Croatia. Appl. Energy 184, 1470–1482. https://doi.org/10.1016/J.APENERGY.2016.06.099

Kontochristopoulos, Y., Michas, S., Kleanthis, N., Flamos, A., 2021. Investigating the market effects of increased RES penetration with BSAM: A wholesale electricity market simulator. Energy Reports 7, 4905–4929. https://doi.org/10.1016/j.egyr.2021.07.052

Lu, B., Blakers, A., Stocks, M., Do, T.N., 2021. Low-cost, low-emission 100% renewable electricity in Southeast Asia supported by pumped hydro storage. Energy 236, 121387. https://doi.org/10.1016/J.ENERGY.2021.121387

Martins, J., Miles, J., 2021. A techno-economic assessment of battery business models in the UK electricity market. Energy Policy 148, 111938. https://doi.org/10.1016/J.ENPOL.2020.111938

Mayyas, A., Chadly, A., Amer, S.T., Azar, E., 2022. Economics of the Li-ion batteries and reversible fuel cells as energy storage systems when coupled with dynamic electricity pricing schemes. Energy 239, 121941. https://doi.org/10.1016/J.ENERGY.2021.121941

Michas, S., Stavrakas, V., Papadelis, S., Flamos, A., 2020. A transdisciplinary modeling framework for the participatory design of dynamic adaptive policy pathways. Energy Policy 139, 111350. https://doi.org/10.1016/j.enpol.2020.111350

Michas, S., Stavrakas, V., Spyridaki, N.A., Flamos, A., 2019. Identifying Research Priorities for the further development and deployment of Solar Photovoltaics. Int. J. Sustain. Energy 38, 276–296. https://doi.org/10.1080/14786451.2018.1495207

MIT Electric Vehicle Team, 2008. A Guide to Understanding Battery Specifications. https://doi.org/10.1007/978-3-319-91488-6_1

Nayak-Luke, R., Bañares-Alcántara, R., Collier, S., 2021. Quantifying network flexibility requirements in terms of energy storage. Renew. Energy 167, 869–882. https://doi.org/10.1016/J.RENENE.2020.12.006

NREL, 2022. Useful Life [WWW Document]. URL https://www.nrel.gov/analysis/tech-footprint.html (accessed 10.24.22).

Oconnell, N., Pinson, P., Madsen, H., Omalley, M., 2014. Benefits and challenges of electrical demand response: A critical review. Renew. Sustain. Energy Rev. 39, 686–699. https://doi.org/10.1016/J.RSER.2014.07.098

Palizban, O., Kauhaniemi, K., 2016. Energy storage systems in modern grids—Matrix of technologies and applications. J. Energy Storage 6, 248–259. https://doi.org/10.1016/J.EST.2016.02.001

Pellow, M.A., Ambrose, H., Mulvaney, D., Betita, R., Shaw, S., 2020. Research gaps in environmental life cycle assessments of lithium ion batteries for grid-scale stationary energy storage systems : End-of-life options and other issues. Sustain. Mater. Technol. 23, e00120. https://doi.org/10.1016/j.susmat.2019.e00120

Perez, M., Perez, R., Rábago, K.R., Putnam, M., 2019. Overbuilding & curtailment: The cost-effective enablers of firm PV generation. Sol. Energy 180, 412–422. https://doi.org/10.1016/J.SOLENER.2018.12.074

Quoilin, S., Kavvadias, K., Mercier, A., Pappone, I., Zucker, A., 2016. Quantifying self-consumption linked to solar home battery systems: Statistical analysis and economic assessment. Appl. Energy 182, 58–67. https://doi.org/10.1016/j.apenergy.2016.08.077

Rai, V., Reeves, D.C., Margolis, R., 2016. Overcoming barriers and uncertainties in the adoption of residential solar PV. Renew. Energy 89, 498–505. https://doi.org/10.1016/J.RENENE.2015.11.080

Retna Kumar, A., Shrimali, G., 2021. Role of policy in the development of business models for battery storage deployment: Hawaii case study. Energy Policy 159, 112605. https://doi.org/10.1016/J.ENPOL.2021.112605

Schmidt, O., Melchior, S., Hawkes, A., Staffell, I., 2019. Projecting the Future Levelized Cost of Electricity Storage Technologies. Joule 3, 81–100. https://doi.org/10.1016/j.joule.2018.12.008

Seward, W., Qadrdan, M., Jenkins, N., 2022. Quantifying the value of distributed battery storage to the operation of a low carbon power system. Appl. Energy 305, 117684. https://doi.org/10.1016/J.APENERGY.2021.117684

Stocks, M., Stocks, R., Lu, B., Cheng, C., Blakers, A., 2021. Global Atlas of Closed-Loop Pumped Hydro Energy Storage. Joule 5, 270–284. https://doi.org/10.1016/J.JOULE.2020.11.015

Süsser, D., Gaschnig, H., Ceglarz, A., Stavrakas, V., Flamos, A., Lilliestam, J., 2022. Better suited or just more complex? On the fit between user needs and modeller-driven improvements of energy system models. Energy 239, 121909. https://doi.org/10.1016/J.ENERGY.2021.121909

The European Parliament and the Council of the European Union, 2018. Regulation (EU) 2018/1999 of the European Parliament and of the council of 11 December 2018 on the Governance of the Energy Union and Climate Action, amending Regulations (EC) No 663/2009 and (EC) No 715/2009 of the European Parliament and of the Council. Off. J. Eur. Union L 328/1.

Timmons, D., Elahee, K., Lin, M., 2020. Microeconomics of electrical energy storage in a fully renewable electricity system. Sol. Energy 206, 171–180. https://doi.org/10.1016/J.SOLENER.2020.05.057

Trondle, T., 2020. Supply-side options to reduce land requirements of fully renewable electricity in Europe. PLoS One 15, e0236958. https://doi.org/10.1371/JOURNAL.PONE.0236958

van de Ven, D.J., Capellan-Peréz, I., Arto, I., Cazcarro, I., de Castro, C., Patel, P., Gonzalez-Eguino, M., 2021. The potential land requirements and related land use change emissions of solar energy. Sci. Reports 2021 111 11, 1–12. https://doi.org/10.1038/s41598-021-82042-5

Weitemeyer, S., Kleinhans, D., Vogt, T., Agert, C., 2015. Integration of Renewable Energy Sources in future power systems: The role of storage. Renew. Energy 75, 14–20. https://doi.org/10.1016/J.RENENE.2014.09.028