Modelling Scenarios for Enhancing the Effective Implementation of Secure, Affordable and Sustainable Electricity on the Greek Islands

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Declaration

I, Eleni Zafeiratou, confirm that the work presented in this thesis is my own. Where information has been derived from other sources, I confirm that this has been indicated in the thesis.

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-Rest at the end, not in the middle

K.B.

Abstract

The Greek islands' power system is fragmented into 29 autonomous electrical systems relying on oil-fired generators to supply 82% of their electricity demand. Local power grids are only allowed to absorb a maximum renewable energy share of approximately 30% to secure the stability of the network and avoid abrupt frequency alterations. Inevitably, fossil-fuel dominated, isolated systems lead to increased generation costs, high carbon intensity and frequent power cuts.

A novel integrated methodological approach has been developed to address these challenges consisting of: I) Long and short-term modelling considering interconnections and energy storage in the form of batteries versus the current energy autonomy, using the PLEXOS integrated energy model (Energy Exemplar, 2019) for a projection horizon extending between 2020 and 2040. II) ISLA demand model (Spataru, 2013), adapted to the Greek islands (ISLA_EGI), preceded by an extensive data processing, to anticipate annual demand scenarios. The two models inform each other and support the analysis of 35 scenarios. III) The development of methods to simulate electromobility in PLEXOS considering various charging strategies.

This analysis contextualises the impact of innovative technologies in providing feasible solutions on the Greek islands in line with the Energy Trilemma Index (security, affordability, sustainability). It was concluded that when combining submarine interconnections and batteries (Scenario IB.x.1.0.a), generation prices were reduced by 42% at the regional and 10% at the national level compared to a BAU scenario (A.y.1.0.a), while carbon dioxide equivalent (CO_2eq) emissions are reduced by 99% and 74% respectively. Also, power outage events are abolished. The benefits of a High-Efficiency demand scenario produced by ISLA_EGI show further reductions of 2.5% in emissions between 2020 and 2040. The results unveil that certain small, remote systems should remain autonomous, supported by battery storage. The operation of EVs highlights that primarily V2G scenarios and occasionally, scheduled unidirectional charging bring the ultimate benefits.

Impact Statement

The main objective of this research project is to provide an in-depth understanding of optimal solutions in the short and long-term for enhancing the effective implementation of secure, affordable and sustainable electricity on the Greek islands. The methodologies and findings included in the thesis have an impact both in the academic and non-academic environments. They are the product of work following discussions and directions provided by the Greek Regulatory Authority of Energy (RAE) and the Hellenic Distribution and Network Operator (HEDNO), which is also the ‘Islands System Operator (ISO)’.

In the academic environment, the energy model developed in PLEXOS provides a framework to analyse future investments and operational conditions on the Greek islands within the regional and national context. The methodology applied complements existing literature, assessing the viability of future interconnections and hybrid systems on islands under a more inclusive approach in line with the Energy Trilemma Index. In this respect, cost-optimisation and high spatio-temporal resolution methods are applied, synthesising infrastructure projects, renewables, energy storage systems and fuels with low CO_2eq emissions intensity. The methods applied are aligned with policies and targets as reflected in the National Energy and Climate Plan (NECP) and other reports, which designate the objectives for decarbonizing the energy sector between 2020 and 2040.

The demand modelling via the adapted version of the ISLA model, ISLA_EGI, provides an in-depth analysis of the Greek islands' electricity demand combining a hybrid approach. An extensive process is applied to decrypt the past and future electricity demand behavioural patterns in households and commercial buildings alongside assumptions considering policies, initiatives, and techno-economic trends. Demand and supply modelling coupling is provided while incorporating ISLA_EGI demand profiles in the PLEXOS energy model. Such an original methodological approach concerning the Greek islands unveils valuable insights for academics and researchers for a sector where information is missing.

Also, the novel model developed to simulate EVs operation in the Greek islands' context proposes a transparent methodological approach to simulate electromobility in PLEXOS with high replicability to other regions across the world.

The benefits for the non-academic sector include findings that could directly impact policymakers in decision-making regarding energy infrastructure planning in a critical period where the Greek electricity system is undergoing a massive transition. Specifically, the results could be of exceptional importance for evaluating the impact of the sizing and timing of future submarine transmission extensions between the islands and the NGS. Secondly, investments in storage are assessed for the first time at different levels and contexts concerning the whole Greek islands region. The impact of energy savings at economic and environmental levels provides understandings for energy efficiency improvements on areas where tailor-made policy recommendations could be proposed while highlighting the impact of specific electricity end-uses and sectors such as tourism for the region.

In addition, although the Greek government has already established a legislative framework for supporting electromobility in Greece, a strategic deployment plan that will signal investments in the Greek islanding region is missing. The results of this thesis highlight that such small island systems will be severely impacted if large volumes of EVs are introduced, designating for policymakers and market operators the optimal smart charging strategies to avoid unserved demand, increased costs, and emissions.

Publications

The methodologies and results of this research have been circulated to a broader audience within and outside academia through publications in peer-reviewed journals and presentations at international conferences as well as business and educational events. The remaining unpublished parts will also be included in future articles. The publications related to this thesis are:

I. Zafeiratou,E, Spataru, C., (2022), Modelling electric vehicles uptake on the Greek islands, Renewable and Sustainable Transition Journal, 2, 100029
II. Zafeiratou,E, Spataru, C., (2019), Modelling electrical interconnections for Rhodes island power system, Conference: 2nd International Conference on Smart Energy Systems and Technologies (SEST), IEEE, Porto, Portugal
III. Zafeiratou,E, Spataru, C., (2019), Long Term analysis of submarine transmission grid extensions between the Greek islands and the mainland, Conference: 2nd International Conference on Smart Energy Systems and Technologies (SEST), IEEE, Porto, Portugal
IV. Zafeiratou, E., Spataru, C., (2018) Sustainable Island power system – Scenario analysis for Crete under the energy trilemma index, Sustainable Cities and Society Journal, 41, pp. 378-391
V. Zafeiratou, E., Spataru, C., (2017) Potential Environmental and Economic Benefits from the Interconnection of the Greek Islands, International Journal of Global Warming, 13, pp. 426-458
VI. Zafeiratou, E., Spataru, C., (2016) Transforming the Greek Cycladic islands into a wind energy hub, Engineering Sustainability, Proceedings of the Institution of Civil Engineers, 170, pp 113-129
VII. Zafeiratou, E., Spataru, C., Bleischwitz, R., (2016) Wind offshore energy in the Northern Aegean Sea islanding region, Conference: 2016 IEEE 16th International Conference on Environment and Electrical Engineering (EEEIC), Florence, Italy
VIII. Zafeiratou, E., Spataru, C., (2015) Investigation of high renewable energy penetration in the island of Syros following the interconnection with the national grid system, Energy Procedia Journal, 83, pp. 237-247

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List of Acronyms

AC	Alternative Current
AES	Autonomous Electrical Systems
AVG	Average
BAU	Business as Usual
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
CAES	Compressed Air Storage
CCGT	Combined Cycle Gas Turbine
CDD	Cooling Degree Days
CFL	Compact Fluorescent
COP	Coefficient of Performance
DC	Direct Current
DoE	Department of Energy (US)
DWHS	Domestic Water Heating System
EC	European Commission
EENS	Expected Energy Not Supplied
EER	Energy Efficiency Ratio
EPC	Energy Performance Certificates
ESS	Energy Storage System
ETI	Energy Trilemma Index
EU	European Union
EV	Electric Vehicle
FBMC	Flow-Based Market Coupling
FiP	Feed in Premium
FiT	Feed in Tarriff
FOR	Forced Outage Rate
G2V	Grid To Vehicle
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiance
HDD	Heating Degree Days

HEDNO	Hellenic Electricity Distribution Network Operator
hh	Household
HR	Heat Rate
HV	High Voltage
HVAC	Heating, Ventilation and Air Conditioning
I	Island
ICEV	Internal Combustion Engine Vehicle
IPTO	Independent Power Transmission Operator
IR	Islands Region
ISLA_EGI Model	ISLA Electricity Greek Islands Model
ISO	Island System Operators
JRC	Joint Research Centre
LCOE	Levelised Cost of Energy
LDC	Load Duration Curve
LED	Light Emitting Diode
Li-ion	Lithium-ion
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LP	Linear Programming
LPG	Liquid Petroleum Gas
LS	Low Sulphur
LT	Long Term
LV	Low Voltage
MAX	Maximum
MIN	Minimum
MIP	Mixed Integer Programming
MT	Medium Term
MV	Medium Voltage
MVA	Medium Voltage Amber
NECP	National Energy and Climate Plan
NG	Natural Gas
NGS	National Grid System

NIIs	Non-Interconnected Islands
NTC	Net Transfer Capacity
NTUA	National Technical Univeristy of Athens
NUTS	Nomenclature of Territorial Units for Statistics
OECD	Organisation for Economic Cooperation and Development
O&M	Operation and Maintenance
OPF	Optimum Power Flow
PASA	Projected Assessment of System Adequacy
PHEV	Plug-in Hybrid Electric Vehicle
PHS	Pumped-Hydro Storage
PPAs	Power Purchase Agreements
PPC	Public Power Corporation
PSO	Public Service Obligation
R	Electrical transmission Region
RAE	Regulatory Authority of Energy
RES	Renewable Energy Sources
S	Scenario
SAIDI	System Average Interruption Duration Index
SCOPF	Security Constrained Optimal Power Flow
SECH	Survey on the energy consumption in households
SHFB	National Survey of Household Financial Budget
SMP	System Marginal Price
SoC	Stateo of Charge
ST	Short Term
UCTE	Union for the Co-ordination of Transmission of Electricity
UoS	Use of System charges
V2G	Vehicle to Grid
WACC	Weighted-Average Cost of Capital for the project
WEO	World Energy Outlook
WPHS	Wind Pumped-Hydro System

1. Introduction

1.1 Summary

This introductory chapter provides background information while it unfolds the key challenges and research gaps that motivated this project. Part of this paper is published in (Zafeiratou and Spataru, 2016, 2018, 2019b, 2019a). Firstly, a general description of the context in that island energy systems operate is provided. The role of renewable energy sources (RES), interconnections and storage on European islands is highlighted via characteristic best practices.

Following on, the Greek islands' electricity system is presented, which is the case study of this research. Facts about the current electricity mix and historical figures about demand trends are discussed. The relevant policies and initiatives at the national and international level and the regulatory and legislative framework are presented. This review highlights a lack of public and private sector incentives to support the clean electricity transition until recently, when European and national policies triggered investments to facilitate a secure, affordable, and sustainable electricity system on the Greek islands.

A detailed description of the challenges under the Energy Trilemma Index (ETI) and the peculiarities of their system operation are presented as well as the challenges related to renewable energy development. Specifically, the vast seasonal demand fluctuations combined with the isolated, fragile networks cause frequent power interruptions. Simultaneously, the oil-fired generation that covers the baseload demand and peaks during the summer months increases further power generation costs in the region, scoring three to five times higher than the mainland. The high emissions levels in the region due to the reliance on oil-fired generation are also discussed.

In relation to the challenges and opportunities concerning the Greek islands' electricity systems, the Research Objectives of this project are presented, emphasising the key areas where they could significantly improve their operation. Finally, in the last section of this chapter, the rest of the thesis structure is exhibited.

1.2 Background & motivation

1.2.1 Context

More than 100,000 islands worldwide, including 2,400 islands in Europe, struggle to secure a reliable energy system with affordable prices and low carbon intensity (Richardson, 2015; NESOI, 2020). The United Nations Conference on Environment and Development acknowledged for the first time that "islands are ecologically fragile and vulnerable" (United Nations, 1992). Two years later, the 'Programme of Action for the Sustainable Development of Small Island Developing States' was established (United Nations, 1994). The United Nations made an explicit reference to small islands under Goal 7 for Affordable and Clean Energy, and specifically in sub-Goal 7.B, which requires sustainable energy services supported by infrastructure expansion and technology upgrade, for access to affordable, reliable, sustainable and modern energy for all by 2030 (Ioannidis *et al.*, 2019).

In the European context, approximately 362[1] are considered principal islands, with more than 2% of Europe's population living on them (Eurelectric, 2012; Spilanis et al., 2013). In particular, Greece possesses 227 inhabitant islands and 80 principal; out of those, 47 remain non-interconnected (Hellenic Statistical Authority, 2012a; Gavalas, 2017). The Amsterdam Treaty recognises in declaration No. 30 that "insular regions suffer from structural handicaps linked to their island status, the permanence of which impairs their economic and social development". Such issues do not allow them to meet electricity and other requirements in a secure, affordable and sustainable way officially declared by the European Treaty/Article 174 (European Union, 2012a; Smilegov, 2013). As islands remain isolated from continental Europe, efforts to achieve the energy transition lag behind other regions (Chen *et al.*, 2007). In this respect, several declarations have been published during the last twenty years to emerge the need for tailor-

[1] (Principal) islands were defined for the European Union by Eurostat as NUTS-3 regions consisting of single islands, island groups or part of a single larger island. Islands included in this regional typology, based on population criteria, have the following characteristics: a minimum surface of 1 km², a minimum distance between the island and the mainland of 1 km, a resident population of more than 50 inhabitants, no fixed link between the island and the mainland (Eurostat, 2015).

made policies and actions for the EU islands. From the Canary Islands & Palma de Mallorca declaration in 1999 and the Chania declaration in 2001 (Cipriano, 2015) to the latest one, in Malta for Clean Energy in EU islands (European Commission, 2017b).

Political and economic barriers, market distortion and lack of benefits of ‘economies of scale’ alongside technical impediments impact negatively efforts to modernise and improve islands' electricity systems concerning the security of supply, electricity affordability and emissions released from power generation. Such practical handicaps can be grouped under the Energy Trilemma Index (ETI) established by the World Energy Council (2019). Originally, the principles of a trilemma and the frequent incompatibility of meeting all three criteria in parallel were presented by Dani Rodrik (2007) in the context of the global economy, while later, Bressand (2012) referred to the tensions between energy security, economic development and sustainability.

The security of supply is a fourfold challenge for islands related to imported oil fuel dependency subject to geopolitical and economic uncertainties, seasonal demand variations, fragile interconnections and local grids, vulnerable to accidents and natural disasters. The climate crisis intensifies risks and may result in long-term power system strains or short-term episodic shocks causing voltage and frequency drops (European Commission Directorate, 2013). As islands' power systems lack resilience, local renewables can rarely exceed 30% of the annual demand resulting in a carbon-intensive generation mix (Oikonomou et al., 2009). The demand is mostly linked to seasonal tourism economic activities; therefore, balancing demand and supply can be incredibly challenging, leading to considerable discrepancies during the year.

Economic Affordability is reflected in the power generation costs driven by oil prices representing the primary fuel, usually exceeding 80% of the islands’ supply mix (Gioutsos *et al.*, 2018). In certain islands in Europe, such as Greece or Italy, the additional power generation costs are subsidised through policies such as the Public Service Obligation (PSO), which contributes to the islanders' economic affordability. According to Blechinger *et al.* (2016), small islands worldwide would save approximately 9€ billion per year in fuel expenditures if they shift their power generation systems towards renewable energies.

In the post-Paris agreement era, emissions continue to rise steadily (Persaud, Flynn and Fox, 1999; IPCC, 2019a). The Lancet Countdown 2020 report states that island regions or states lead in topics around engagement in health and climate change as they are severely affected by the impacts of the climate crisis (Watts *et al.*, 2020). One of the key reasons is their reliance on fossil fuels for electricity uses, which are responsible for more than 40% of the energy-related Green House Gas (GHG) emissions (World Nuclear Association, 2021). However, islands possess a significant yet unexploited renewable energy potential that could exceed 30 GW globally (Blechinger *et al.*, 2016). That could set the example for more extensive on-grid applications (Li, Chalvatzis and Stephanides, 2018). Also, the rapid decrease in renewables capital expenditure (CAPEX) makes them cost-competitive compared to diesel systems (IRENA, 2018). Thus, beyond the economic savings, clean, renewable sources could support islands globally in reducing emissions from the electricity sector by 50%, according to Blechinger et al. (2016).

To ensure a reliable, economically affordable and low-carbon electricity system on islands, it is important to invest in robust long and short-term planning, inhibiting policymakers from prioritising energy security over climate change mitigation policies and vice versa. Additionally, when optimally integrated into the islands' electricity systems, an up-to-date selection of appropriate technical solutions such as transmission infrastructure, energy storage systems (ESS), and electric vehicles (EVs) frame the required actions toward sustainability.

1.2.2 The role of renewables, energy storage and interconnections on the European islands

Best practices on islands' electricity systems across Europe pave the way towards decarbonisation and innovation by deploying clean, smart and efficient solutions, improving ETI performance. Despite islands comprising small challenged regions, they are flexible and adaptable to change compared to large regions with monolithic energy governance (Chalvatzis, 2009; Ioannidis et al., 2019). Key catalysts towards their development have been initiatives such as the ISLENET network (1995), followed by the ISLEPACT (2009) project and the Pact of Islands (2011) [2], which engaged island authorities to commit towards achieving a minimum of 20% CO_2 emissions reduction by 2020. Furthermore, the Covenant of Mayors (2008) and the 'Clean Energy for EU Islands Initiative' were established (European Commission, 2016c, 2017a). The latter established the 'Clean Energy Secretariat' in 2018, facilitating the energy transition on EU islands (European Comission, 2021). Finally, the 'European Islands Facility – NESOI'[3] launched in 2020 is funding 60 energy transition projects on EU islands, mobilising more than 100€ million investments contributing actively to reducing GHG emissions by 2023 (NESOI, 2020).

Figure 1.1 illustrates the most characteristic examples of interconnected and non-interconnected islands at the European level applying innovative RES projects. These cases act as inspiration for defining the objectives and means of this research project by exploring clean local energy sources and mobilising investments with long-term employment and regeneration opportunities for islands (Rynikiewicz and Snape, 2010; Spataru, 2019).

[2] https://www.islepact.eu/

[3] https://www.nesoi.eu/

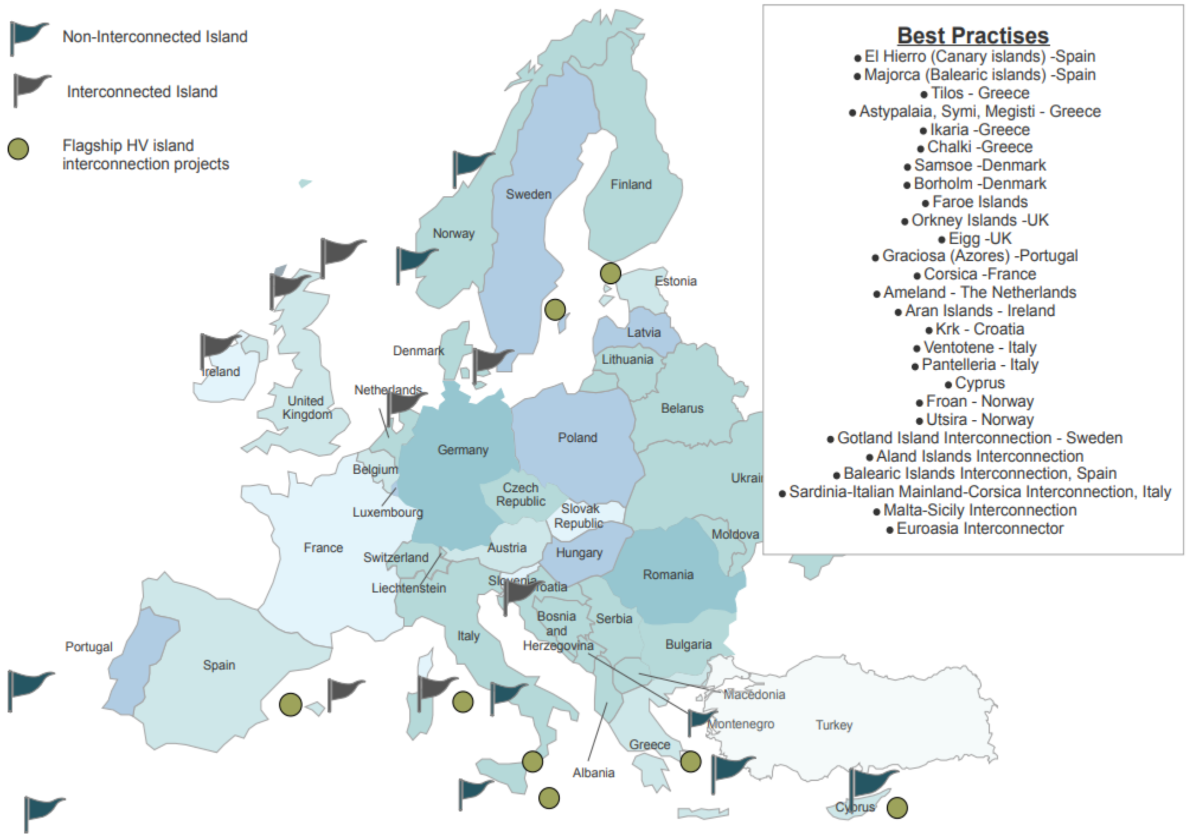

Figure 1.1: Examples of best practices on European islands

Scandinavia hosted the first island interconnection in 1954, including a 90 km-length cable between Gotland and the Swedish mainland (Spataru, 2019). The same island was chosen for a pilot to install demand response, storage and small-scale distributed generation in parallel with solar power, avoiding the further expansion of wind turbines due to local reactions (Clean Energy for EU islands Secretariat, 2019). Samsoe island in Denmark was one of the first (1997) to install a plethora of RES projects, with an annual average of 100% RES supply (Lin, Wu and Lin, 2016). The island is now going through the 'Samsoe 3.0' phase, prioritising circular economy activities. Another island in Denmark, Bornholm, interconnected with the mainland, has launched the 'Bright Green Island' community project to become a carbon-neutral community by 2025 (Aegean Energy Agency, 2016). In Bornholm, the EcoGrid 2.0 has been realised, targeting enhancing the system's reliability and flexibility while providing peak shaving services through an instantaneous price indication mechanism (EcoGrid, 2016). Continuing with the good practices, the Faroe islands charge electric cars through the renewables surplus while installing batteries of 2.3 MW/0.7 MWh (Eurelectric, 2017). In parallel, electromobility is supported through public quick-charger infrastructure. Due to the high RES potential, the electrification of heating and cooling sectors has been proposed, with consumers participating in a load-shedding mechanism (Eurelectric, 2012).

In the same region, the EU-funded REMOTE project[4] demonstrates the technical and economic feasibility of two Fuel Cell Hydrogen (FCH) energy storage solutions deployed in different off-grid remote areas, including the Froan Island in Norway. While using RES deriving from a PV-wind hybrid system, this project aims to provide the necessary electricity loads to support residential consumption and the local fish industry (REMOTE, 2018). Furthermore, within the BIG HIT[5] EU-funded project, the community-owned W/Ts and tidal generators will generate electricity to produce hydrogen through electrolysis in the Orkney islands in Scotland. Mobile storage H_2 units are transported on ferries. They are used to supply hydrogen to a refuelling station for local Fuel Cell EVs, two heating systems as well as a fuel cell heat and power system that provides auxiliary heat to the main harbour and power to three ferries (BIG HIT, 2018).

Best practices in the Mediterranean basin include Cyprus, with the 'SmartPV8' project regulating auto-consumption from photovoltaics and the 'Green+, Zero Energy Mountains' initiative aiming to optimise decentralised solar energy integration in rural areas. Additionally, a large-scale 50 MW solar thermal power plant of parabolic type has been installed (Zachariadis and Hadjikyriakou, 2016). In Ventotene island in Italy, 300 kW/600 kWh, Lithium-ion (Li-ion) batteries have been installed, which assisted in avoiding curtailments by reducing fuel consumption by 15% (Eurelectric, 2017). Beyond the state-of-the-art HV AC interconnection project with the Spanish mainland, Majorca island aims to become the world's first hydrogen (H2) island (Ardelean and Minnebo, 2015; RED Electrica de Espana, 2015). In addition, the ‘ecaR project’ has provided the first electric charging network on the island (Eurelectric, 2017). Finally, the island of Krk is set to become Croatia’s first 100% RES island and the first CO_2-neutral and energy-

[4] https://www.remote-euproject.eu/

[5] https://www.bighit.eu/

self-sufficient island in the Mediterranean by 2030. Notably, 150 GWh potential is possible with a combination of solar and wind technologies. (Clean Energy for EU Islands Secretariat, 2019; Reuters, 2021). Beyond the Mediterranean territories, El Hierro in the Canary islands archipelago has been one of the most renowned islands, becoming a 100% renewable energy island (Rodrigues et al., 2015). Biogas is produced alongside the Wind Hydro Pumped Storage (WPHS) system by utilising stockbreeding effluents and sewage for methanogen fermentation.

Today, the longest island interconnection in the area is the Sardinia-Italian mainland cable of 420 km, also linking the island of Corsica in France with Italy (Ardelean and Minnebo, 2015). With upcoming projects such as the Crete interconnection, the new HV DC interconnections are expected to achieve even longer lengths. The longest planned interconnection in the region is the Euroasia interconnector which is expected to interconnect through 1000 km of submarine cables, Israel, Cyprus, Crete island and the Greek mainland (EuroAsia Interconnector, 2013).

In Greece, the Tilos project co-funded by the European Union (EU) Horizon 2020 programme demonstrates the first 100% RES energy-dependent island with 800 kW wind turbine (W/T) and 160kW photovoltaic (PV) panels alongside NaNiCl2 battery storage of 2.88 MWh/800kW (Piraeus University of Applied Sciences, 2019). The interconnection with the Kos electrical system will allow exchanging loads while also providing ancillary services to the neighbouring islands (Chatzivasileiou, 2017; Piraeus University of Applied Sciences, 2019). In Ikaria, a hybrid project has been installed, including a wind farm of 2.7 MW linked to the grid alongside a hydro 3 MW pump station consisting of two reservoirs of 4.15 MW total capacity (JRC, 2019; Spasić, 2019). The system is expected to produce more than 12,000 MWh of clean energy annually. Other flagship projects concern the electromobility transformation of Astypalea island as 1,500 internal combustion engine vehicles (ICEVs) will be replaced with electric ones, accompanied by solar and wind energy projects. Also, the Chalki project under the GR-Eco initiative aims to reduce 1.8 $MtCO_2eq$ via solar PV and electromobility, expanding to electric ferries. The ‘Agios Efstratios – Green Island’ initiative comprises a hybrid power station including a district heating network aiming for RES penetration higher than

85% (Hellenic Republic - Ministry of the Environment and Energy, 2017c; Volkswagen, 2020; Energypress, 2021). In the context of the 'Clean Energy for EU Islands' initiative, two more islands, Symi and Megisti, will be converted into smart islands in combination with mini-grids and storage units, with the ultimate goal to increase renewable energy to at least 60% of the total energy produced (HEDNO, 2019a). Finally, the Cycladic Islands interconnection was the first HV AC submarine interconnection project completed in the Aegean Sea allowing the decommission of significant installed thermal capacity (Zafeiratou and Spataru, 2016).

1.3 The Greek islands' electricity system

Greece has the most extensive coastline in the Mediterranean basin, with thousands of islands demonstrating particular geomorphology, complicating the implementation of new decentralised power plants and electrical grids. Notably, the Greek power system has the peculiarity of comprising more than 80 principal islands with a total permanent population of 1,067,018 (Hellenic Statistical Authority, 2012a). Out of those, 47 remain as non-interconnected Islands (NII), with their electricity distribution network not connected to the transmission system or the distribution network of the mainland. The Greek NIIs are grouped into three main geographical regions: South Aegean, including the Cyclades and the Dodecanese islands, North Aegean and Crete. Skyros island, incorporated in the analysis, belongs to the Sporades complex (Figure 1.2).

The main professional activities of the locals are related to the tertiary sector, especially tourism, which is one of the leading industries for the Greek economy and the principal source of income for the islands. In complementarity, islanders are active in agriculture and farming. Due to economic growth constraints, the Greek islands region is challenged by an aged local population recording an increased average of 2.5 years compared to the continental part of the country. Besides, it phases higher unemployment and economic volatility reflected in a 50% lower income per capita compared to the urban centres (Hellenic Statistical Authority, 2016a).

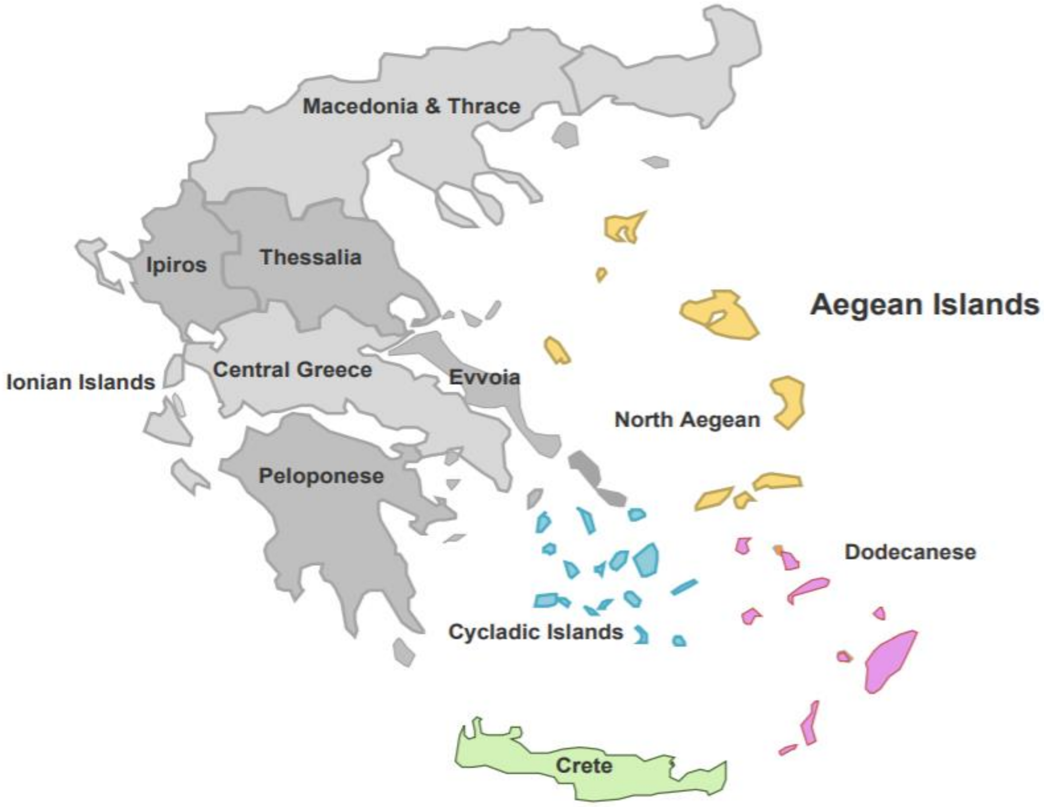

Figure 1.2: Map of the Greek islands regions (IR)

In total, the Greek islands remaining partially or fully non-interconnected comprise 29 autonomous electrical systems (AES), herein considered as independent transmission regions (R) (Table 1.1), clustered according to their size based on the annual peak demand[6]. Until the recent Cycladic islands interconnection, partially completed in 2020, including Syros, Mykonos and Paros electrical systems, Greece counted 32 non-interconnected systems (58 islands) (Zafeiratou and Spataru, 2016). Crete's interconnection is currently the second HV AC project in the Aegean Sea. In the context of this study, we will continue considering the Cycladic islands as a region in the phase of transition since no major RES development has taken place yet, taking advantage of their interconnectivity while local thermal stations are partially active. Non-interconnected islands (NIIs) use mainly heavy fuel oil (HFO) or diesel engines for power generation, with a total

[6] Very small systems concern those with annual peak demand less than 1 MW, small are those between 1 MW and less than 10 MW, medium concern those between 10 MW and 100 MW, large sized systems are those with annual peak demand larger than 100 MW (RAE, 2021c).

capacity of 1750 MW[7], while the annual peak is near 1320 MW (HEDNO, 2020b). The renewable energy capacity consisting mainly of solar and wind due to the favourable weather conditions is limited to 444 MW (HEDNO, 2020a). Biomass is represented through a 1 MW project and similarly hydropower through 0.3 MW as well as the Pumped Hydro Storage (PHS) project of Ikaria described before. The power production on the islands accounts for 10.7% of the total Greek electricity generation, with disproportional costs.

Table 1.1: The Greek islands' autonomous electrical systems (AES)

AES (Region)	Islands	Size	Popu-lation	Annual Peak (2016)	AES (Region)	Size	Popu-lation	Annual Peak (2016)
Crete	Crete	Large	631,812	627.30	**Skyros**	Small	3,020	4.65
Rhodes	Rhodes, Chalki	Large	117,496	200.00	**Symi**	Small	2,630	3.84
Kos-Kalimnos	Kos, Kalimnos, Leipsi, Tilos, Telendos, Gyali, Pserimos, Leros, Nisyros	Medium	61,030	94.50	**Serifos**	Small	1,460	3.42
Paros [8]	Paros, Antiparos, Naxos, Koufonisi, Shoinousa, Ios, Folegandros, Irakleia, Sikinos	Medium	36,212	68.20	**Amorgos**	Small	2,003	3.15
Lesvos	Lesvos, Megalonisi	Medium	87,198	67.42	**Kythnos**	Small	1,674	2.98
Chios	Chios, Oinouses, Psara	Medium	53,138	46.80	**Astypalaia**	Small	1,360	2.21

[7] Before the Cycladic islands interconnection completion the total installed capacity was exceeding 1880 MW

Thera	Thera, Therasia	Medium	15,470	42.80	**Megisti**	Very Small	492	0.91
Mykonos [8]	Mykonos, Delos, Rineia	Medium	10,268	41.80	**Anafi**	Very small	271	0.59
Samos	Samos, Fournoi, Thymaina	Medium	34,877	29.60	**Donousa**	Very Small	167	0.36
Syros [8]	Syros	Medium	21,790	23.70	**Agios Efstratios**	Very small	272	0.31
Lemnos	Lemnos	Medium	17,142	14.70	**Othoni**	Very Small	340	0.26
Milos	Milos, Kimolos	Medium	5,051	12.28	**Ereikousa**	Very Small	612	0.35
Karpathos	Karpathos, Kasos	Medium	7,406	11.30	**Agathonisi**	Very small	185	0.20
Ikaria	Ikaria	Medium	8,549	6.70	**Arkoi**	Very Small	44	0.14
Sifnos	Sifnos	Medium	2,665	6.22	**Gavdos**	Very small	152	0.12
Patmos	Patmos	Medium	3,092	5.90	**Antikythira**	Very small	44	0.11

[8] Recently interconnected electrical systems

1.3.1 Electricity demand and supply

The Greek islands had seen an increase in electricity demand since 1970, when tourism flourished for the first time in the region. Since then, more than 1000% demand growth has been recorded (Hellenic Statistical Authority, 2016a; The World Bank, 2021). Between 2007 to 2012, no considerable fluctuations were recorded, according to Figure 1.3. As of 2013, gradual growth in electricity demand which signified an analogous increase in tourists' arrivals, is observed, following the global economic recovery. The services sector mainly drives demand growth, including tourism and other commercial uses. Between 2012 and 2018, tourism arrivals increased 86% in the islands’ region (Benaki, 2019). However, as tourists tend to arrive during the summer, excessive peaks are recorded, putting the islands' power system at risk and affecting the security of supply criterion.

On the contrary, the residential sector sees a smaller increase due to the economic crisis which hit Greece between 2008 and 2017. The rest of the sectors have a limited impact on the islands' economy, while a slight reduction is recorded in activities related to industry and agriculture over time. The economic crisis in the electricity sector is also observed in the steep decline following 2008 at a national level. As the residential and industrial sectors have a larger demand share in the Greek mainland, the implications of the austerity are more evident compared to the islands region, which is much affected by non-domestic tourism.

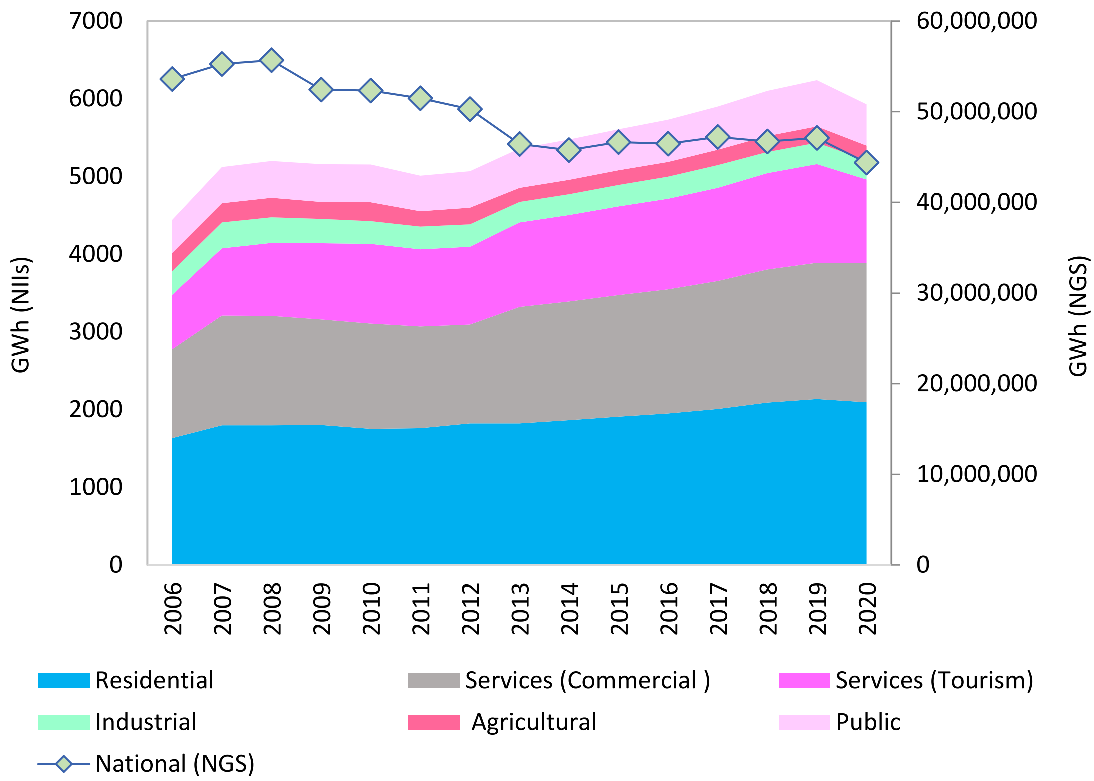

Figure 1.3: Historical electricity demand on the NIIs and the National Grid System (NGS) (Hellenic Statistical Authority, 2016a; Hellenic Republic - Ministry of the Environment and Energy, 2019c; IPTO, 2021b)

The Greek NGS plays a catalytic role in the operational conditions of the islands when they become interconnected. Therefore, alongside the local resources, the national electricity mix, the storage support, and the submarine extensions' technical features will shape the future landscape of the islands' electricity sector. Currently, the final energy consumption in Greece relies 88% on conventional fuels. Concerning the Greek electricity generation mix, approximately 25% still relies on national fuel reserves such as lignite, even though Kardia I & II power plants with 550 MW retired in 2019 with multiple impacts against the ETI. In this respect, Greece is phasing out gradually old lignite power stations such as Amyntaio, Kardia III & IV and Megalopoli II & III (IPTO, 2014b). Overall, all existing lignite units should be retired by the end of 2023, with a possible derogation according to the system requirements no later than 2028. Natural gas (NG) has gained ground over the last years, becoming Greece's principal power supply source while participating 39% in the generation mix. Studies show that it will remain the primary source of electricity until 2025, when renewables such as solar are supposed to take the lead, according to the Greek National Energy and Climate Plan (Hellenic Republic - Ministry of the Environment and Energy, 2019b). Currently, renewables, including large-scale hydro plants, represent 37% of the total electricity supply in Greece. At the same time, estimations show that they have the potential to reach more than 60% by 2030 and 77% by 2050 (Hellenic Republic - Ministry of the Environment and Energy, 2019a).

Oil has been the principal power source for the Greek NIIs ranging between 75-100%, with an average share of 82%. RES have been participating in the islands' electricity mix since 1982, when the first W/T on a European island, Kythnos, was installed. Islands such as Samos, Crete and recently Ikaria enjoy higher RES penetration as a combination of high wind and solar potential, favourable spatial configurations and PHS support. As seen in Figure 1.4, a moderate increase in wind energy generation is evidenced following 2008, especially in medium and large-sized systems triggered by the law 3468/2016, which established a concrete framework for renewable energy production in Greece for the first time (Hellenic Republic - Ministry of the Environment and Energy, 2006). Wind energy is still utterly absent in small and very small networks due to the technical restrictions and lack of interconnectivity combined with low energy demand. Solar energy has been mainly present since 2009, enacted by laws 3468/2006 and 3852/2010, contributing to nearly 5% of the total generation mix (Hellenic Republic - Ministry of the Environment and Energy, 2006, 2010b; HEDNO, 2020a). Even though RES installed on islands enjoy higher tariffs than the mainland, technical restrictions due to lack of access to the grid, high capital costs, public opposition, and environmental concerns still hinder RES expansion. A notable observation is that in 2018 with the first part of the Cycladic interconnections connecting Syros, Paros and Mykonos completed, the local generation was reduced by 5.4% due to the replacement part of the local generation with imports. In 2019, Greece bounced back with a record in tourists arrivals outweighing the interconnection impact with a larger RES share. In 2020 a reduction was observed due to the COVID-19 pandemic implications.

The average monthly power generation profiles demonstrate high discrepancies due to demand seasonality, reaching 53% between the minimum load recorded in November and the maximum in July. As aforementioned, this divergence is attributed to increased tourists' arrivals between June and August, creating strain on the local network.

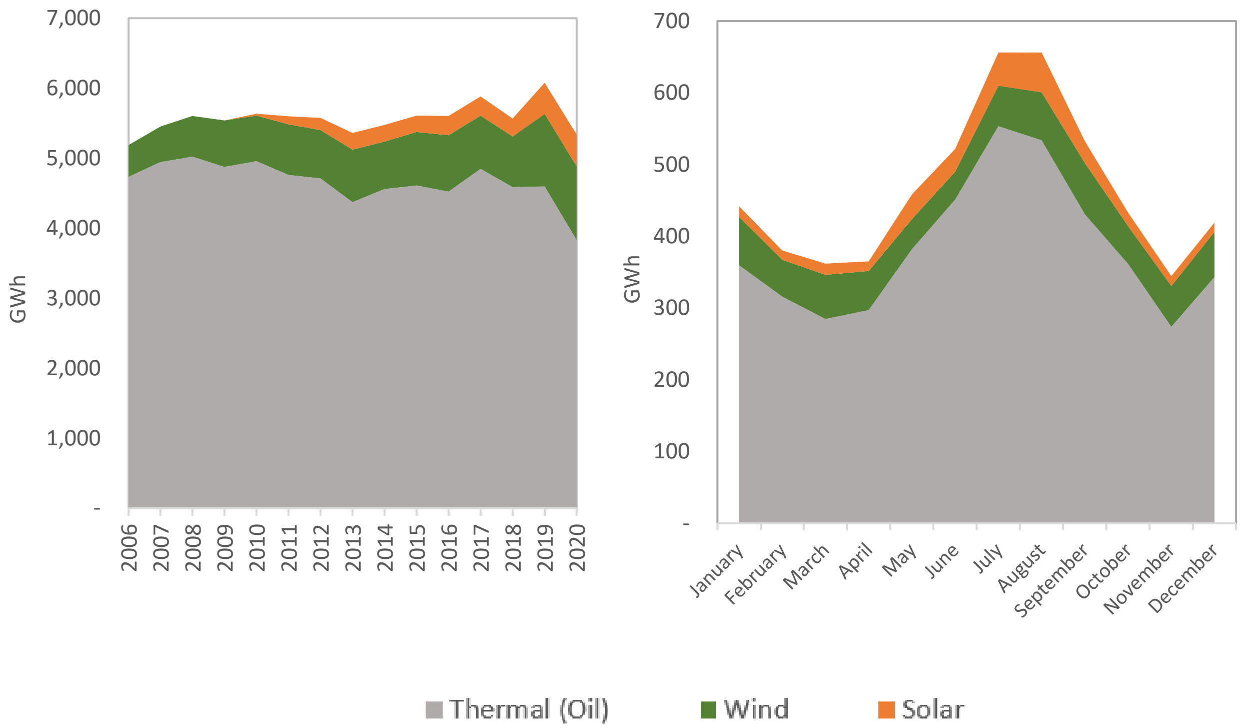

Figure 1.4: Annual and average monthly power generation supply (2020) on the NIIs (IPTO, 2019; HEDNO, 2020a)

1.3.2 Regulatory and policy framework

Until recently, the islands were operating in a monopolised regime regarding the production, operation, and electricity supply undertaken by the Greek 'Public Power Corporation (PPC)' except for renewable energy. Crete and Rhodes, the two largest non-interconnected islands generating more than 60% of the electricity produced on the NIIs, were the first islands to apply energy liberalisation in the power supply. The rest of the Greek NIIs are considered isolated micro-systems (HEDNO, 2020a). Whilst a significant margin of almost 30% of the supply has been allocated to private players, the thermal generation market remains under the

Greek PPC territory as private companies have expressed no interest in the oil fuel generation industry.

The Hellenic Electricity Distribution Network Operator (HEDNO) or DEDDHE is the Islands System Operator (ISO). The authority in charge of designing and implementing the HV transmission extensions, including islands interconnections, is the Greek Independent Power Transmission Operator (IPTO) or ADMHE, while the Electricity Market Operator is called DAPEEP. Finally, the Hellenic Energy Exchange (HEnEx) is currently the Operator of the Energy Derivatives Market, the Day-Ahead Market and the Intra-Day Market applicable to the Greek mainland and the fully interconnected islands considering interconnections that can cover the islands' annual peak demand.

In 2011, following the unbundling imposed by Law 4001/2011 (Hellenic Republic - Ministry of the Environment and Energy, 2011), HEDNO became an independent body in charge of the operation of the distribution network in Greece. HEDNO succeeded PPC as the ISO and is also responsible for operating, maintaining, and upgrading local Low and Medium Voltage (LV and MV) grids across the country (Iliadou, 2009). With the support of HEDNO, the final NIIs Code was published in February of 2014. The Code targets improving the current energy system on the NIIs and supports liberalisation by allowing new players to participate as energy suppliers and producers. The main principles are to promote the reduction of high costs in the Greek AES, guarantee the secure and smooth operation of the system, and increase RES share in the local energy market (Hellenic Republic - Ministry of the Environment and Energy, 2014c). Under the Code's provisions, the structure of a single day-ahead market and the participation of power generators and load representatives in the NIIs market have been defined. In this respect, all participants declare hourly loads at least 12 hours before the next delivery day with an obligation of physical delivery. At the same time, the ISO ensures that the scheduled generation equalises the forecasted demand on each AES. The market clearance is performed every month (RAE, 2020a).

In the context of an integrated electricity market, in 2014, the European Commission proposed that the 10% interconnection target should be extended to

15% by 2030 (European Commission, 2016a), as it has become commonly accepted that the energy transition cannot be attained without adjusting the infrastructure to facilitate larger amounts of clean energy. This solid European framework is accompanied by the ratification of directives 2010/75/EU and 2015/2193/EU which have set new standards for emissions released and environmental restrictions on the operation of existing combustion plants stations to limit the production of sulphur dioxides (SO_2), nitrogen oxides (NO_x) and dust (European Union, 2010, 2015). In light of these reforms, a series of new infrastructure investments have been scheduled on the Greek islands to improve the operational conditions of the local power systems. These reforms are also supported by the ‘Market Reform Plan’, published in 2021, that aims to actively support a capacity remuneration mechanism with reliability options and promotion of flexibility with participation of generation, demand response, storage and interconnections in Greece (RAE, 2021b).

Such projects will allow the Greek islands to align with the EU Green Deal strategy, which imposes cutting emissions by at least 55% further while RES penetration increases from 32% to 40% in the energy mix (European Commission, 2020a). More particularly, Greece aims to cover 61% of its electricity consumption from renewable sources by 2030. Similarly, at least a 32.5% improvement in energy efficiency is required compared to 2007 consumption projections for 2030 (European Commission, 2020a). Greece has configured a more ambitious target of 38% by 2030, with the residential sector benefiting through the 'Savings at Home' scheme supporting deep house renovations. A further revision of the targets to reach a 39% reduction in primary energy consumption has been proposed at the EU level (European Commission, 2021a).

The Greek government has acknowledged the fundamental value of islands for the country’s energy transition and economic growth (Tsagkari and Jusmet, 2020). For this reason, Greece's ‘10-year Development Plan’ includes solutions for the islands region (IPTO, 2021b). Submarine grid extensions have been planned to be implemented throughout the upcoming decades to facilitate a regional super-grid among the Greek islands and the mainland, potentially expanding into third countries. In case this is not doable to techno-economic hinders, the deployment of self-sufficient hybrid electrical systems has to be foreseen. Currently, a detailed schedule for the ongoing interconnection of the Cycladic and Crete islands has been in place, and the budget has been allocated. Also, a preliminary roadmap to interconnect the rest of the South Aegean and North Aegean Sea islands has been published.

Specific policies have been in place to incentivise the RES development on islands. A Feed-in-Tariff (FiT) scheme was established in 1994 as remuneration for RES that was replaced with a Feed-in-Premium (FiP) scheme in 2016, considering projects in the Greek mainland and islands. FiP is an additional amount added to the price received by RES projects through their participation with zero price energy offers in the wholesale market. According to legislation 4414/2016, following 2016, RES will continue to benefit from a fixed remuneration via ‘Power Purchase Agreements (PPAs)’ as long as the islands remain non-interconnected with the mainland or have not established a fully operational day-ahead market (Hellenic Republic - Ministry of the Environment and Energy, 2016b). If the energy producer undertakes the cost of the submarine cable, there is a maximum of 25% bonus on top of the FiT/FiP. The remuneration of hybrid stations will be subject to auctions. Mature projects on islands with small competition will temporarily compensate through FiT (Panagoulis, 2020; Tsagkari and Jusmet, 2020).

Furthermore, law 4685/2020 enabled the acceleration of the permitting process for RES. In parallel, it set a framework for waste management on the Greek islands (Hellenic Republic - Ministry of the Environment and Energy, 2020a). Under this legislation piece, environmental permits must be issued within approximately 45 days, while the issuance of the energy production certificate takes place through an online system reducing times from years to months.

RES could become a source of income and economic development for remote communities such as islands, drawing examples from the European Federation of citizen energy cooperatives (Möller *et al.*, 2012; REScoop.EU, 2021). In this respect, the return of 3% of the gross profit of RES projects goes to the municipalities in proximity to the renewable energy projects. Also, the Greek State published the 4513/2018 legislation framework promoting cooperatives for the direct participation of the islanders in renewable energy projects (Hellenic Republic - Ministry of the Environment and Energy, 2018b).

Regarding energy storage, the laws 3851/2010 and 4414/2016 include comprehensive provisions about the use of hybrid stations on islands and the NGS (Hellenic Republic - Ministry of the Environment and Energy, 2010b, 2016b). Furthermore, the EU-funded ‘Tilos Hybrid Project’ triggered legislation for small hybrid battery-renewable energy projects, particularly for cases where the storage system will operate in stand-alone and grid-connected systems (Tsagkari and Jusmet, 2020). However, Greece is lagging behind the other Member States as, regardless of being the first country in the EU to implement a detailed regulation promoting hybrid systems’ installation (Krajačić *et al.*, 2011), there is no reference to other energy storage technologies such as utility battery storage, hydrogen, compressed air energy storage (CAES), etc. Hence, only hybrid projects using PHS have been typically permitted, except for Crete Island, which hosts large-scale Battery Energy Storage Systems (BESS) plans. Inclusive legislation, including all types of storage technologies and how they will operate in the Greek electricity market, is anticipated in 2022, given that the NGS will need approximately 1,500 MW to 1,750 MW of new energy storage capacity to meet 60% of its 2030 electricity needs via renewable energy (Tsagas, 2020; Hellenic Republic - Ministry of the Environment and Energy, 2021).

Electromobility has been considered a key priority for decarbonising the transport sector in Greece and the Greek islands, strongly linked to tourism activities and their huge carbon footprint in the transport sector. Greece targets one of every three new vehicles to be electric by 2030 in parallel with the installation of 10,000 public chargers (Zarkadoula, 2020). In 2021, 1120 EVs were driven on Greek roads while the number of public chargers did not exceed 334, with 31 of them are located on the NIIs (European Union, 2014; European Alternative Fuels Observatory, 2021). These have been installed under HEDNO’s plan for at least one electric charger on every island with peak demand higher than 1 MW. On islands such as Crete, the number of chargers will soon reach 35, whereas, for Rhodes and medium-sized islands, the target is to reach at least ten chargers per island by early 2023. (Stavropoulou, 2018).

Finally, Greece plans to publish a new policy framework for offshore wind in 2022. Given the characteristics of the deep Greek waters, the predominant technology to be applied will be floating offshore wind (Buljan, 2021). So far, several applications have been submitted, especially in the Northern Aegean Sea; however, none has proceeded to the actual implementation. The new legislation is anticipated to support the development of a maximum of 2 GW in the region, demonstrating opportunities for synergies with the islands' submarine interconnection infrastructure.

1.3.3 Electricity system challenges under the ETI

The previous regulatory and policy gaps alongside the techno-economic barriers leading to low-RES integration levels challenge the already complex operation of the Greek island electricity systems. Such challenges are aligned with the Energy Trilemma Index (ETI) (World Energy Council, 2020), and nowhere in the world is the ETI more broadly pronounced than in the restrained space of remote islands. The ETI was adapted herein to fit the scope; therefore, Energy Security, Energy Equity and Environmental Sustainability were adapted to Security of Supply, Electricity Affordability (given the fact that accessibility is considered guaranteed across all inhabitant islands) and Environmental Sustainability in terms of carbon equivalent (CO_2eq) emissions reduction.

Even though no available ETI scores exist for the Greek islands' region, the figures concerning Greece shape the country's profile, emerging a series of shortcomings. Greece scored 39th in the world ranking of WEC in 2020 (Figure 1.5) (World Energy Council, 2020) with noticeable areas of improvement in the Energy Security and Equity sectors, while there is clear progress in Environmental Sustainability due to the political will to phase out lignite stations. A few critical factors influencing the ETI performance are the high oil import dependency and the remoteness of several NIIs regions. Thus major reforms are requested, including improvements in energy efficiency, enhanced submarine transmission extensions, and investments in utility energy storage and EV charging infrastructure. Hence, the main path to adjusting current conditions is decarbonising the energy system with high-RES shares. However, overarching, technological, environmental, economic, regulatory, public acceptance and administrative barriers hinder the rapid expansion of RES, particularly on the Greek islands.

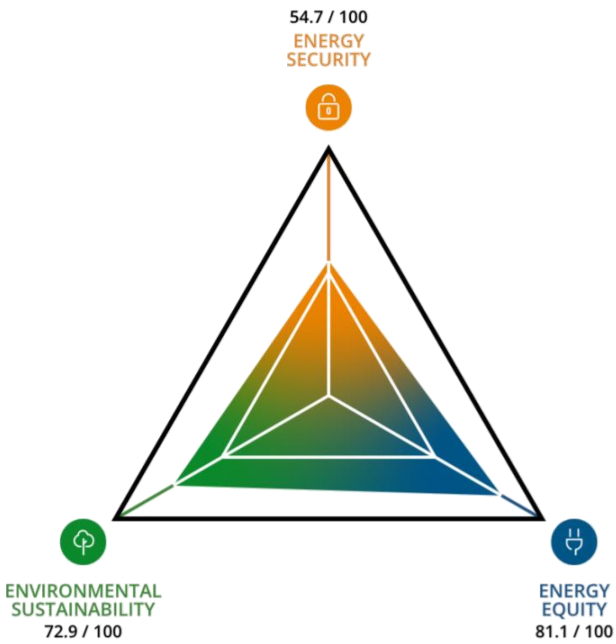

Figure 1.5: ETI performance for Greece (World Energy Council, 2020)

The most significant technical obstacle is renewable energy's non-synchronous, intermittent nature when combined with autonomous and fragile power network systems. According to technical regulations, the ISO does not allow intermittent RES integration to exceed approximately 30%-35% of the hourly load demand while considering system dynamic and inertia constraints and the technical minima of the conventional thermal generators (Maroulis, 2013; RAE, 2020a). Such constraints applied to secure the stability of the electrical network and prohibit abrupt frequency alterations have been included as inputs in the scenario modelling analysis to reflect the maximum absorbed RES generation on islands under autonomy.

Even in interconnected islands, wind energy development remains low due to social acceptance and complex permitting processes. The main concerns are related to the W/Ts landscape and environmental disturbance, visual impact, the traditional architecture and noise disruption (Eduardo, Silva and Lekunze, 2008). According to RAE, the maximum limit of wind installations in the partially interconnected region of the Cyclades is 0.53 WT/km^{2}[9]; however, the currently

[9] Considering a typical wind turbine (W/T) with rotor diameter equal to 85m (Voltera, 2013)

installed capacity does not exceed 15% of the maximum number (Hellenic Republic - Ministry of Environment and Energy, 2008). Several discussions have also been triggered regarding the environmental impact of large-scale wind projects. However, there is scientific evidence that W/Ts do not affect agricultural and farming activities and birds' fatality (Binopoulos and Haviaropoulos, 2012), especially when new transmission lines are underground. Several islands are mainly occupied by low trees and bushes, so deforestation is usually contained. Additionally, islands' residents relate large-scale wind implementation with a reduction in tourism arrivals (The Tourism Company, 2012; Regeneris Consulting and The Toursim Company, 2014).

Regarding solar energy, the rough terrain alongside limited land areas and traditional architecture restrain the implementation of large-scale PV projects. Biomass, hydro and geothermal are characterised by increased costs combined with unavailability of the source, which constitute less attractive technologies for scaling up.

Along with the continuously changing tax environment, the Greek economic recession increased the risk and discouraged investors in the past years. As a result of the prolonged economic crisis, in 2013, the government reduced FIT retroactively for solar and wind energy (Hellenic Republic, 2014a). These actions created uncertainty in an already volatile setting, resulting in projects' postponement or cancellation. Overall, the lack of RES integration combined with the existing operational conditions has challenged NIIs systems operation, as described in the next section.

1.3.3.1 *Security of supply*

Power shortages on islands leading to unserved demand occur when supply cannot meet end-users demand. The three most common causes are natural causes, human error, and overload (Tara Energy, 2020). Such events may be tackled in the AES by generation and transmission infrastructure investments in the long-term as well as operational constraints in the short-term. On the contrary, RES curtailments, either scheduled or unscheduled, concern system-wide oversupply incidents and local transmission constraints and occur when renewable electricity to be dispatched is higher than the system's demand (Specht, 2019).

A few factors influencing the security of supply that may result in system power shortages or curtailments are the high oil import dependency and the remoteness of several NIIs regions. Such criticalities request measures to improve energy efficiency, increase submarine transmission extensions, and invest in utility energy storage and EV charging infrastructure. The Greek NIIs currently phase volatile demand fluctuations throughout the year wherein some instances, such as on Rhodes or Kos islands, exceed 1000%. This phenomenon results in generation overcapacity, necessary to cover summer peak, low load factors and consequently low efficiencies of the electrical usage. The average load factor of the Greek NIIs for 2020 is presented in Figure 1.6, calculated according to Eq. 1.1. It is observed that most of the systems present low load factors due to the high peaks recorded during summer. On the contrary, the island of Ikaria demonstrates the highest load factor, which is positively influenced by the operation of the WPHS.

$$\boldsymbol{f_{Load}} = \frac{\boldsymbol{Load_t}}{\boldsymbol{Annual\ Peak\ load_t * t}}$$

Eq. 1.1

Where 't' is the timeframe considered, herein is 8760 hours.

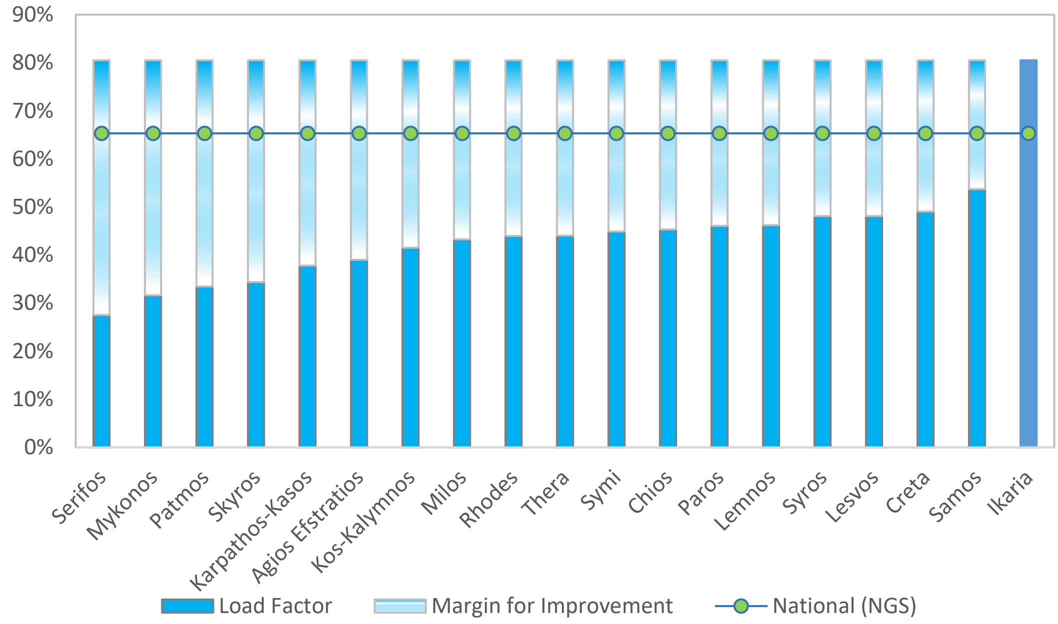

Figure 1.6: Load factors for the NIIs & NGS (2020)

To guarantee the AES smooth power supply, the ISO is imposed to proceed to often scheduled outages. Beyond active and reactive power, the islands have to ensure sufficient voltage and frequency control, which stimulates the available resources to compensate for any imbalance (IRENA, 2018). These ancillary services are offered so far, mainly via diesel or gas turbines that can be quickly ramped up or down their generation.

Despite the preventive maintenance over the winter and the leasing of additional mobile diesel generators over the summer, unscheduled power outages have been unavoidable. Figure 1.7 illustrates the 'System Average Interruption Duration Index (SAIDI)' factor (Eq. 1.2) for all the NIIs compared to the national figures. The results demonstrate evidently that several islands exceed the national average and the median value according to IEEE standards (IEEE Power Engineering Society, 2012), which is translated into increased hours of unserved energy per customer. Beyond the several short, frequent power cuts recorded on islands, significant incidents have resulted in blackouts, such as the Thera blackout, which left the island without power for more than 48 hours during a high season (Arkouli, 2013).

$$\mathbf{SAIDI} = \frac{\sum \mathbf{T_R} * \mathbf{C_R}}{\mathbf{C_T}}$$

Eq. 1.2

Where:

'T_R' is the annual outage time for each independent transmission region (R);

'C_R' is the number of customers in each R;

'C_T' is the total number of customers in all regions.

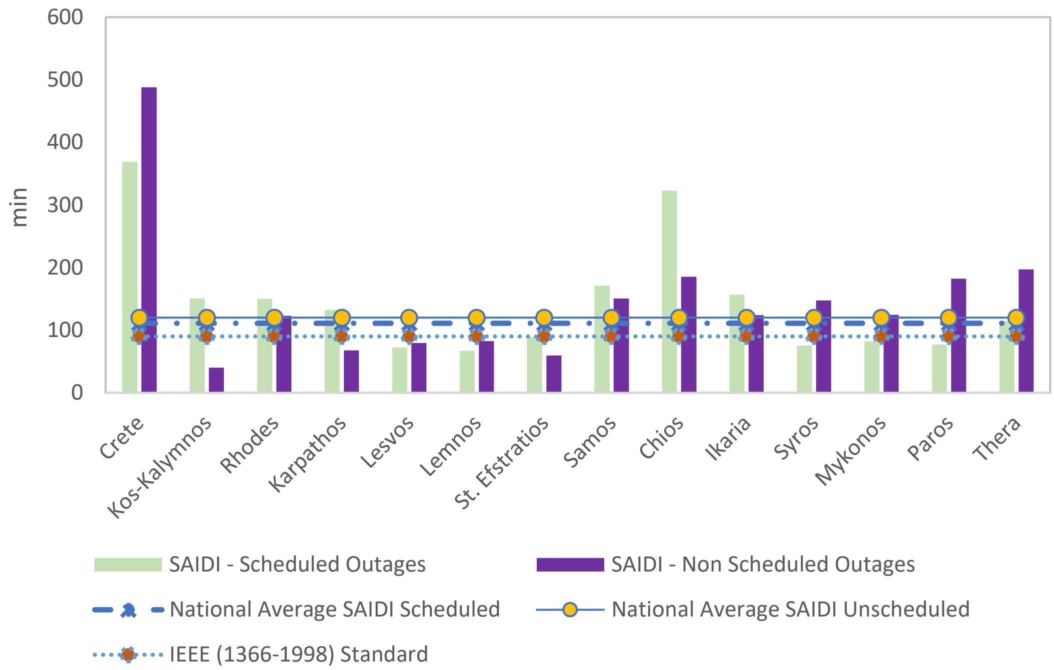

Figure 1.7: SAIDI scheduled and unscheduled values for the NIIs

To improve the quality of supplied energy and control future incidents remotely, the Greek ISO has installed new Control and Data Acquisition - Data Management System (SCADA-DMS) of the required remote-control equipment in the MV and HV substations and the new control centre for distribution networks. The systems will also operate proactively to avoid corrective measures, while congestion phenomena and loss of load episodes will be constrained (HEDNO, 2019c).

In the event of geopolitical or economic crises, Greece's extensive reliance on third-party countries importing on average 1,300 ktoe of oil per year only for electricity generation[10] could potentially pose threats to the resilience of the

[10] considering the status before the Cycladic islands interconnection was completed

electricity system in the islands region. This is, however, only one aspect of the consequences linked to reliance on oil-fuel sources. Directives 2010/75/EU and 2015/2193/EU humper power generation from oil-fired steam and gas turbines to 1,500 and 500 h/year respectively, from 2020 concerning small isolated systems, such as Crete. Whereas Crete has been derogated from its full compliance until 31/12/2021 in view of its interconnection with the mainland, this measure will eventually apply across the entire NIIs region in Greece irrespectively of the size of the system. In this respect, as of 2025, the newest fleet of commissioned oil-fired generators will be introduced to the islands' systems between 2010 and 2018 and diesel generators <50 MW will be imposed to reduce operation. From 2030 that number decreases to 500 h/year horizontally (European Union, 2010, 2015). Considering that electricity consumption on the Greek islands (per capita) is higher than inland consumption, with increasing growth trends, such measures could result in demand and supply imbalances and power insufficiency.

1.3.3.2 *Economic affordability*

Oil fuel prices and related taxes followed an exceptionally high path for most of the previous decade. Following the enactment of the NIIs code in 2014, an exact formula was set in place to calculate the marginal system costs based on the merit dispatch order of the generators participating in the island systems. The average (AVG) variable generation cost for the region over the last seven years was 209 €/MWh (HEDNO, 2017a), according to Figure 1.8. The total mean cost, including fixed costs, was estimated to be 451 €/MWh (HEDNO, 2020b). In contrast, the wholesale electricity market price in the NGS has been significantly lower through the historical period, with an average value close to 53.7 €/MWh with a declining trend (IPTO, 2021a).

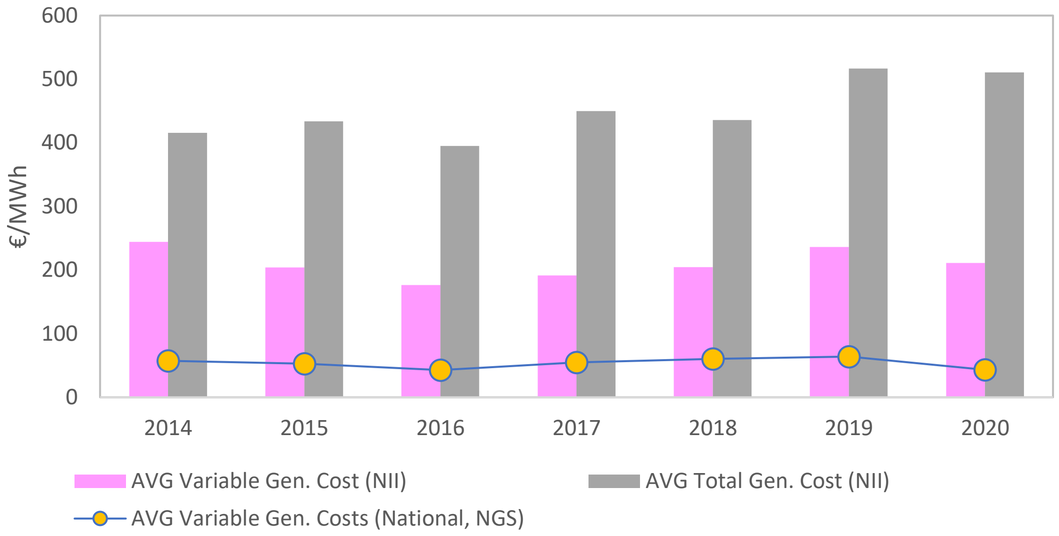

Figure 1.8: Average generation costs on the NIIs and NGS (2014-2020)

These additional costs are isomerised between the Greek consumers in the NGS and the NIIs, through the PSO policy to avoid discrimination between the inhabitants of the mainland and the islands (Tsagkari and Jusmet, 2020). PSO is a unified price policy established initially by Law 2773/1999 and amended with the current Law 4001/2011 (Hellenic Republic - Ministry of the Environment and Energy, 1999, 2011). RAE published in 2014 the decision, which introduced the calculation method for estimating precisely the PSO from the NIIs (Eq. 1.3) (RAE, 2014). Socio-economic assumptions and parameters are updated on a triennial basis and are reflected on the published approvals for attributing the PSO to the PPC.

$$PSO = \sum_{R,m} \{[(Variable\ Costs_R + \ Fixed\ Costs_R) - SMP)] * GNII_R + [(\frac{\sum_R Variable\ Costs}{R}) - SMP] * GRES_R - UoC_R\}$$

Eq. 1.3

Where:

'R' is the transmission region configured by each island AES;

'm' is the month;

'SMP' is the system marginal price at the national level;

'GNII' is the thermal power generation in every AES;

‘GRES’ is the power generation from RES in each AES;

‘UoC’ is the use of system charges that electricity consumers pay for access to the electrical grid per sector, which was calculated as described here:

$$UoC_R = \sum_{m}^{12} UoC_{domestic} + UoC_{commercial,public} + UoC_{touristic} + UoC_{others}$$

Eq. 1.4

$$UoC_{R,s,m} = RCFc_s * kVA_s * {}^{Days\ used}/_{365} + (\text{ Number of Buildings}_{R,s} * \text{Average Consumption}_{R,s} * \ RCVc_{R,s})$$

Eq. 1.5

Eq. 1.6

Where:
‘s’ is the sector (domestic, commercial, public, touristic, others);
‘m’ is the month;
‘RCFc’ is the Regulated Consumers Fixed Charges;
‘RCVc’ is the Regulated Consumers Variable Charges.

The total PSO was calculated to be approximately 482.6€ million for 2016 (Hellenic Republic - Ministry of the Environment and Energy, 2017a). The additional cost between the non-interconnected and interconnected parts is included in the consumers' electricity bills of all residents in Greece. The tariff varies from 6.9 €/MWh to 85 €/MWh depending on the residential sector's volume and daily power consumption. For Commercial Low Voltage (LV) users, the cost is 18.24 €/MWh, and for MV 17.9 €/MWh, while for MV industrial and agricultural customers, the amount is 6.9 €/MWh, according to the latest data published by the Regulatory Authority for Energy (RAE, 2021a). In contrast, the subsidisation for RES is currently at 17 €/MWh and is expected to decrease as the LCOE of commercialised technologies such as solar and wind is reduced, while such projects will not be eligible for subsidies as of 2024 (Liagou, 2021; RAE, 2021a).

Part of PSO is attributed to carbon emissions from power stations located on the islands, as PPC operating the oil-fired stations is imposed to pay fees to the

European Emissions Trading System (EU ETS) in case of excess of the allowed emissions levels through the Directives 2003/87/EU and 2009/29/EU (European Union, 2003, 2009a). Carbon emissions allowances prices have initially configured at a price of 6 €/tnCO_2 in the NIIs region in 2014, which remained until the middle of 2017 (Hellenic Republic - Ministry of the Environment and Energy, 2014b). However, the revised and ambitious EU targets in parallel and the establishment of the Market Stability Reserve (MSR), have lifted emissions allowances to 28 €/tnCO2 in 2020, with increasing trends for the next decades as projected by the European Commission (2016b, 2017c). According to the latest available data, the Greek PPC had to pay the excessive amount of 363€ million in 2018 for the additional emissions permits from thermal power plants on the NIIs.

1.3.3.3 *Environmental sustainability*

Public electricity and heat production are responsible for one-third of all CO_2 emissions and are the largest and second-largest sources after transport of SO_2 and NO_x emissions, respectively (European Environment Agency, 2013). In the Greek islands' region, diesel and HFO power generators are the predominant sources of power for Greek islands causing severe air pollution in the area with CO_2 equivalent (CO_2eq) emissions (including CO_2, SO_x and NO_x) exceeding 22 million tonnes over the last five years. This amount equals 12% of the total carbon emissions from the power sector in Greece (Ritchie and Roser, 2021).

Considering a net efficiency factor of 30% for oil thermal power plants, the average carbon intensity for the NIIs is estimated to be 0.88 tnCO_2/MWh in 2016. On the other hand, the carbon intensity of the Greek interconnected electrical system was estimated to be 0.71 tnCO_2/MWh (IEA, 2014). Projections show a further decrease, as lignite power stations will gradually retire and replace within the next five years by approximately 4 GW of RES. The portfolio will include 125 MW of large hydropower stations and nearly 1.7 GW of NG power plants, out of which 370 MW have already been licensed (IPTO, 2014b; Hellenic Republic - Ministry of the Environment and Energy, 2019a). In light of the major shift towards clean electricity generation in the mainland, solutions such as submarine interconnections combined with energy storage and RES emerge the vast potential for decarbonising the islands' electricity systems.

1.4 Research objectives

The contextual introduction described the vulnerability of islands energy systems while providing insights on the role of key clean energy solutions adopted by the European islands showing evidence that the electricity sector's transition is feasible.

In Greece, the NIIs region experiences high generation costs, increased carbon emissions and a fragile, unstable power network with frequent power disruptions prohibiting RES penetration. These three parameters shape the ETI, presented in Section 1.3.3 adapted to fit the particularities of the Greek islands electricity system. The ETI provides a criteria framework that allows applying optimisation and simulation methods to provide clean, affordable and reliable electricity supply on the Greek islands and defines the main Research Question**:** ***Which is the optimal solution in the short and long-term for enhancing the effective implementation of secure, affordable and sustainable electricity on the Greek islands?***

In order to answer the research question, an integrated methodological approach has been developed (as described in detail in Chapters 3 and 4), and several scenarios have been analysed, assessing the role of renewable energy, interconnections, energy storage, and EVs at different levels and contexts. Such an analysis is framed around the key research objectives and the adopted methods specified in Table 1.2 and illustrated in Figure 1.9.

Table 1.2: Research objectives and methods applied to address them

Nr	Research Objective	Adapted ETI parameter	Methods and models	Methodology Section	Results Section
I	To assess the impact of future demand scenarios incorporating energy efficiency policies on the electricity generation mix.	-Electricity Affordability -Security of Supply -Environmental Sustainability	-Demand data collection & extensive analysis through a hybrid model -Annual demand scenarios development in ISLA model (adapted to Greek Islands and named ISLA_EGI)	3	3.6 (also in 5.2.1.2, 5.2.3, 5.3.2, 5.3.4, 5.4.1.2)
II	To examine how interconnections and battery storage systems could contribute to the future electricity security and supply.	-Security of Supply	-Assess the impact of deployment scenarios through reliability indicators -PLEXOS model developed for the Greek Islands	4.5 4.6	5.2
III	To identify the least-cost electricity mix under two main scenario storylines: Interconnections vs. Autonomous operation.	-Electricity Affordability	-Long Term cost optimisation expansion planning in PLEXOS model -Increased spatio-temporal modelling resolution at short term simulation	4.4 4.5 4.6	5.3
IV	To measure the impact of future interconnections vs. autonomous operation on reducing CO_2eq emissions at the regional and national level.	-Environmental Sustainability	-Assess the level of CO_2eq emissions under various scenarios -Sensitivity analysis in PLEXOS model	4.4 4.5 4.6	5.4
V	To assess EVs penetration scenarios against the ultimate target to increase the share of RES, enhance resilience without increasing costs.	-Electricity Affordability -Security of Supply -Environmental Sustainability	-Incorporates EV deployment and charging scenarios for the Greek Islands while developing a modelling framework in PLEXOS model	4.7	5.2.6 5.3.3.1 5.4.2

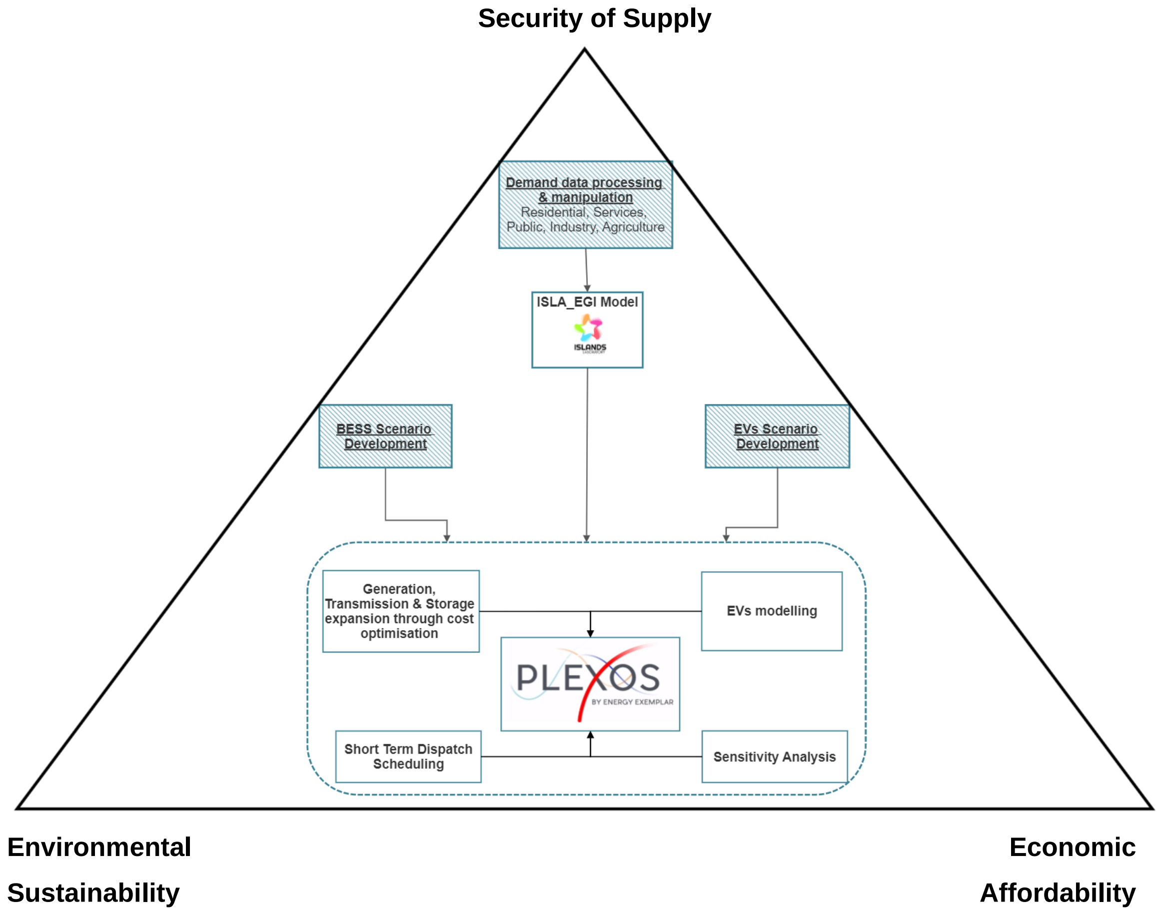

Figure 1.9: Summary of adopted methods and models

The Research objectives highlight the novelty pursued under this PhD while exploring a wide range of technical solutions to support the transition of their electricity systems through secure, affordable, and sustainable means. For the first time, demand analysis is conducted for the region through the ISLA model (Spataru, 2013)[11], incorporating data following a detailed methodological approach based on household surveys. Also, energy efficiency measures concerning the local building stock from the National Energy and Climate Plan (NECP) and other public reports were included. Results from the demand modelling are introduced in the model developed in PLEXOS (Energy Exemplar, 2019), which is extensively used by energy regulators, academic institutions and utilities. PLEXOS allows combining long-term investment forecasts with short-term generation dispatch, which is essential to explore the impact of interconnections, energy storage, renewables, and other techno-economic variables on the islands' electricity from

[11] https://www.islandslaboratory.com/copy-of-research

different spectrums. Finally, a model has been developed for EVs deployment and penetration through charging scenarios assessing the implications of transport electrification on the Greek islands.

1.5 Thesis structure

The remainder of the thesis is divided into five chapters:

Chapter 2 reviews studies and methodical approaches for simulating and optimising scenarios for secure, economically affordable, and sustainable electricity. An inclusive overview of optimisation electricity models performing short-term dispatch and long-term generation, storage and transmission expansion planning is included. Furthermore, literature on methods applied for simulating high-RES integration concerning the Greek NIIs complemented by international literature is explored, including future interconnections and stand-alone operation using energy storage. Demand modelling reflected in bottom-up and top-down approaches is also discussed. Finally, literature about the EVs' integration into power systems under various charging scenarios is presented. This chapter highlights the contribution to the literature and justifies the selection of the PLEXOS energy systems model in relation to the scope of the thesis and the literature gaps.

Chapter 3 presents the methodological approach to define the Greek islands' future annual demand profiles up to 2040 using the ISLA model, adapted to ISLA EGI concerning the electricity sector of the Greek Islands (EGI) corresponding to Research Objective I. The two surveys used as data sources are presented, and the bottom-up data processing approach followed to build the 2016 residential demand profiles for each end-use is described. Similarly, the non-residential demand profiles split into the commercial, tourism, and other sectors are configured. A top-down approach to projecting future demand is presented. The methodology, including the assumptions integrated, is validated against real data for 2016. The results represented via the Low and High-Efficiency scenarios are inserted in the PLEXOS model, assessing the impact of different demand trajectories on the investment decision modelling.

Chapter 4 describes the methodological approach adopted to optimise the electricity system of the Greek islands under various scenarios, corresponding to the methodology of Research Objectives II to V. Autonomous and Interconnected conditions are demonstrated as the two main scenario streams while by assessing the impact of battery energy storage, four principal scenarios are configured. Sensitivity analysis on various parameters, e.g., demand, fuel prices, carbon prices, infrastructure availability etc., is formed in a total of 35 scenarios. PLEXOS is presented, including its mathematical formulation, used to model generation and transmission expansion and simulate electricity dispatch. Furthermore, all the assumptions considered in the modelling exercise are presented and validated, including conventional and renewable generation, transmission and energy storage. The EVs modelling approach in PLEXOS is discussed alongside two EV demand growth scenarios and seven charging strategies to investigate the optimal pattern for increasing RES penetration in the islands region without jeopardising the system's reliability. Also, a dedicated scenario concerning Tourism and two V2G scenarios are applied to investigate their impact on EV demand on islands.

Chapter 5 includes the main results of this analysis categorised according to the three key areas aligned with the ETI. The main scenarios and the sensitivity analysis are presented for the projection horizon 2020-2040, aiming to identify the optimum solutions for the future electricity system of the Greek islands. Also, the EVs' impact on the system across the ETI dimensions is presented. The results prove that the interconnection is a one-way solution for most islands, reducing costs and emissions through renewable energy penetration. In parallel, it preserves and improves systems reliability as it provides the necessary interconnectivity with the mainland. Eventually, as RES with little flexibility grow and simultaneously local synchronous generators are decommissioned, even the interconnection option will require storage support in the form of BESS to assure the continuous and smooth power supply. The perks of a high-efficiency demand scenario as generated in Chapter 3 via the ISLA_EGI model are highlighted among the results. However, certain smaller islands perform better in the Autonomous context supported by BESS. Concerning EVs, V2G smart-charging and occasionally nigh-time scheduled options seem to have considerable economic and environmental benefits for the Greek islands' power system.

Chapter 6 provides conclusions and discussions on the Greek island power system's transition to becoming reliable, affordable and sustainable. The Greek electricity system's performance under the ETI at the national level is compared against the four principal scenarios while also applying sensitivity analysis. Each island's electrical system provides a similar assessment at the regional level. The optimum scenarios based on the key research findings, usually those proposing interconnections coupled with BESS, are contextualised, and recommendations are provided on the basis of accelerating clean and innovative energy systems on islands. Finally, this research's contribution and novelty are highlighted in parallel with the limitations encountered, followed by the concluding remarks.

2. Literature Review

2.1 Summary

In line with the thesis research objectives, the literature review has been structured to identify novelty and gaps concerning methods and modelling approaches evaluating the role of interconnections, energy storage, demand and electromobility in facilitating high-RES penetration in secure, affordable and sustainable island electrical systems.

In this respect, the first section provides an inclusive overview of the available state-of-the-art modelling tools used to analyse electricity systems operating under a high share of RES and models accommodating generation, ESS, and transmission expansion between different regions in line with the scope of this research project. A portion of this section is based on common work conducted by Omotola, Zafeiratou and Spataru (2018), titled ‘A comprehensive methodological review on electricity interconnections with high renewable energy penetration in energy system models.

The second part includes a comprehensive overview of research scrutinising methods for integrating renewable energy on the Greek islands. Two approaches are mainly covered, either the submarine transmission extensions to the mainland or neighbouring islands or via the deployment of various energy storage forms focusing mainly on pumped hydro storage (PHS) and BESS. Examples of case studies of islands at a global scale have complimented the literature review.

Demand modelling is covered mainly by bottom-up, top-down and hybrid approaches. Most of the bottom-up methods published relied on household surveys as resources, while limited research has been conducted for non-residential sectors. Top-down approaches have also emphasised the residential sector relying on socio-economic indicators. Hybrid models are found to help blend micro with macroeconomic approaches.

Finally, EV modelling was covered by exploring different charging strategies and EV penetration levels as well as their impact on the grid. This chapter identifies the literature gaps while building on existing studies to propose an inclusive and robust methodology for simulating and optimising the Greek islands’ electricity systems. Part of this section is published in (Zafeiratou and Spataru, 2022).

2.2 Modelling approaches

Modelling scenarios and their environmental, economic and technical implications for the Greek islands' electricity systems require a short-term unit commitment analysis incorporating a detailed representation of the examined power system. As RES play a catalytic role in designing future electricity systems, a robust and comprehensive dataset for renewable energy generation with high spatial and temporal resolution is also required to replicate the electricity system's operation and accurately identify systems costs. In parallel, transmission and ESS expansion planning are essential to building the necessary infrastructure to accommodate clean energy on islands as well as to secure the necessary flexibility. In particular, long-term modelling can significantly improve the results by avoiding overestimating electricity from renewable energy (Pina, Silva and Ferrão, 2013). Also, energy storage support requirements emerge while ensuring the security of supply.

2.2.1 Optimisation electricity models

The electricity models reviewed consider the operation of the electricity sector and the investments required to ensure a smooth and reliable operation. The models most rely on bottom-up approaches and can be categorised according to their short and long-term modelling features in Dispatch, Investment and Integrated models, as presented in Table 2.1. They have been applied in various analyses and case studies and integrated as part of their methodology, interconnections, RES generation, and storage at different levels and dimensions. They are highly relevant to addressing challenges in the islands' electricity system operation.

Dispatch models identified in the literature deal with the short-term economic dispatch and the detection of the cost-optimum output based on the examined electricity generation facilities. Their main objective is to meet the system load requirements subject to several operational and transmission constraints. The

Investment models produce the cost-optimal long-term investment decisions in transmission expansion planning, constrained by several economic, technical and environmental criteria. The projection timeframe is required to be long enough to cover milestone years and the pre-and post-effect in terms of emissions releases of the new units built on the electricity system. These models capture the uncertainty of transmission and generation expansion planning in interconnected networks. The last and most extensive category is the **Integrated models**, which capture the long-term capacity expansion planning of infrastructures and the short-term unit commitment of power plants in energy systems.

The dispatch and expansion planning optimisation is mainly based on linear or mixed linear integer approaches. Linear programming (LP) constitutes a pivotal element in improving the economic effect of mathematical modelling (Eiselt and Sandblom, 2007). Generally, LP is a highly efficient problem where all constraints are linear and continuous. The solution to meet the linear constraints is called a feasible solution, while combining all feasible solutions is called a feasible region (Ma, Yang and Zhang, 2012). Several electricity dispatch and integrated models use linear optimization as it is simpler, incorporating the lowest number of constraints and saving computational time.

However, the requirement to capture the integer dimensions of variables requires Mixed Integer Programming (MIP) employment. From its name, the only part of the variable is limited to an integer, which is recommended for solving unit commitment problems as it allows for a more precise and realistic dispatch scheduling. Due to the increasing improvements in commercial solvers and the growing computational force of modern computers, MIP has gained ground in the research community. Several models have been developed in recent years based on this technique. LP and MIP are usually written in GAMS, MATLAB or Python programming languages while using solvers. MIP incorporates integer variables to generate integer results in transmission and generation expansion planning, considering whole units and lines. It also includes binary variables and a minimum operation constraint to capture the on and off decisions of generators' commitment and dispatch subject to a higher electricity and heat cost in the MIP model (compared to the LP). Another important element of MIP is that electric network constraints can be considered in the analysis (Erik Delarue and D’haeseleer, 2008). Rounded relaxation methodology integrates the unit commitment decisions in a multi-pass optimization while providing integer solutions. It also allows faster solutions because it uses a finite number of linear programming passes rather than integer programming (Economic Consulting Associates, 2020).

Other relevant methods identified in the literature concern 'Heuristic Optimisation Approaches', which differ from traditional optimization modelling as they usually optimise the model to the approximate solution (Fuchs and Völler, 2011; RWTH Aachen University, 2018). Heuristic optimization producers, introduced as experience-based optimization methods, are mechanisms to optimise complex problems where mathematical methods cannot provide a solution in finite time. Usually, they aim to optimize a nonconvex and non-linear optimization problem with a series of intense equality and inequality constraints such as the combined heat and power economic dispatch (Nazari-heris, Mohammadi-ivatloo and Gharehpetian, 2018). Furthermore, stochastic models may be used in complementarity with the above to provide methods for minimizing or maximizing an objective function when randomness is present (Glynn, 2004); herein, stochasticity has mainly been considered concerning RES treatment and outages.

Table 2.1: Optimisation electricity system models

Model	Representation of RES	Optimisation Approach	Programming tool	Temporal representation	Maximum Projection/ Simulation Horizon	Spatial representation	Representation of power flow in interconnection lines	Energy Storage	Reference
Dispatch									
EFI's Multi-area Power market Simulator (EMPS)	Stochastic	Dynamic programming, LP	GAMS	One week with a duration curve to model variations in demand	10 years	Fixed (The Nordic System and Northern European system)	NTC (The model has the option to apply detailed power flow analysis)	PHS	(EnergyPLAN, 2013), (SINTEF, 2014)
EnaPLAN	Deterministic	LP	N/A (it can integrate Power Factory model)	15-60 min	Flexible	Multiregional	AC OPF	PHS, other storage options	(Energynautics, 2016)
EnerPol	Deterministic	N/A	GIS	Hour	One year	Multiregional (Europe, USA, Canada, and parts of Africa and Asia)	AC OPF	PHS	(Eser *et al.*, 2016)
EUROpean Dynamic Simulator (EuroDys)	Stochastic	MIP	MATLAB	Hour	Flexible	Regional (Europe)	NTC	PHS, Batteries	(Spataru and Barrett, 2012)

EUPower Dispatch	Deterministic	MIP	GAMS	Hour	One year	Fixed (32 countries in Europe)	NTC	PHS	(Smart Electricity Systems Research Group, 2012)
WILMAR	Stochastic	MIP	GAMS	Hour	One year	Multiregional	NTC	All	(Weber *et al.*, 2009), (Meibom *et al.*, 2006)
METIS	Stochastic	LP	Python solved by FICO Xpress optimization solver	Hour	One year	Fixed (32 counties in Europe)	NTC	PHS, Batteries	(Sakellaris *et al.*, 2018), (European Commission, 2021b), (Bardet *et al.*, 2016)
Investment									
European Model for Power System with (high shares of) Renewable Energy (EMPIRE)	Stochastic	LP	Xpress-Mosel Solver	Annual, 5years etc	40-50 years	Fixed National (Europe)	NTC	All technologies	(Skar, Doorman, Pérez-Valdés, *et al.*, 2016)
GENESYS	Stochastic	Heuristic Optimisation, Covariance Matrix Adaptation Evolution Strategy	Stand-alone	Hour	2050	Country level (EUMENA)	NTC	All technologies	(Bussar *et al.*, 2016; RWTH Aachen University, 2018)

MESEDES	Stochastic	MIP	GAMS	Hour	10 years	Multiregional	Not Available	N/A	(Unsihuay-vila *et al.*, 2011)
Norwegian University of Science and Technology model	Deterministic	Heuristic optimization method-Ant colony system	MATLAB	One representative hour of the year	Annual	Multiregional (adapted for the Nordic power system Great Britain)	DC optimal power flow		(Fuchs and Völler, 2011)
Stochastic two-stage optimisation model	Stochastic	MIP	Gurobi	Hour	10 years	Multiregional (adapted for the United Kingdom)	NTC	PHS	(Van Der Weijde and Hobbs, 2012)
TEPES	Stochastic	Benders' Decomposition	GAMS	Years, Periods, Sub-periods and load levels, user defined	30 years	Multiregional	DC optimal power flow/ Option for NTC representation	PHS	(Universidad Pontificia Comillas, 2015)
Tsinghua University model	Deterministic	MIP	MATLAB	Hour	Flexible	Multiregional	DC optimal power flow	All technologies	(Zhang, Hu and Song, 2013)
Integrated									
ATLANTIS	Deterministic	MIP	Stand-alone	Monthly (2 peak and 2 off peak periods)	2050 (1 year time step)	Fixed (29 countries in Europe)	DC OPF	PHS	(Stigler *et al.*, 2015)
COMPETES	Deterministic	LP, MIP	AIMMS/GUROBI	Hour	User Defined	Fixed, (All European Countries)	Net Transfer Capacities, DC OPF	PHS, CAES	(Hobbs, Rijkers and Wals, 2004;

									Ozdemir *et al.*, 2013)
DIETER	Deterministic	LP	GAMS, Solver CPLEX and more	Hour	Annual	Fixed Germany	-	Batteries, Hydrogen, PHS, CAES	(DIW Berlin, 2017)
DIMENSION	Deterministic	LP	GAMS	Hour	2050 (flexible time step)	Fixed (28 countries in Europe)	DC OPF using power transfer distribution factors	All technologie s	(Richter, 2011)
Dynamic System Investment Model (DSIM)	Deterministic	LP	Stand-alone	Hour, Day, Annual	2050	Fixed (Europe and North Africa)	N/A	All technologie s	(Strbac *et al.*, 2012)
E2M2s	Stochastic	LP	GAMS	2 hours (12 days in a year), Annual	2050	Fixed (30 countries in Europe)	DC optimal power flow using power transfer distribution factors	PHS	(Swider and Weber, 2007; Spiecker, Vogel and Weber, 2013)
ENTIGRIS	Deterministic	LP	GAMS, Solver: IBM ILOG CPLEX optimizer	Hour, 5 years	2050	Flexible	NTC	Batteries, PHS, Thermal Storage	(Fraunhofer ISE, 2016; Senkpiel *et al.*, 2016)
ELectricity MODel (ELMOD)	Stochastic	MIP	GAMS	Hourly (24 hours in a year), annual or multiple years, user defined	2050	Fixed (European UCTE grid)	DC OPF	PHS	(Leuthold, Weigt and Hirschhausen, 2012)

Electricity Market Complex Adaptive System (EMCAS)	Deterministic	Agent based LP	N/A	Hour, Day	Flexible	Multiregional (has been adapted for Asia, Europe, Africa and United States)	DC optimal power flow	N/A	(Koritarov, 2004; Macal *et al.*, 2014)
Long–term Investment Model for the Electricity Sector (LIMES)	Deterministic	LP	GAMS/ CPLEX	5/10 years 4 times slices each 6 hours long (for 12 days in a year)	2050	Fixed (29 countries in Europe and 8 countries in Middle East North Africa)	NTC	All technologie s	(Nahmmacher , Schmid and Knopf, 2014)
Lappeenranta University of Technology energy model (LUT)	Deterministic	LP	N/A	Hour	2030 (Fixed year)	Multiregional (has been adapted for Asia, Australia, Europe, North America, South America and Sub-Sahara Africa)	NTC	All technologie s	(Bogdanov, Breyer and Asia, 2016)
Medium Term SIMulator (MTSIM)	Deterministic	LP	MATLAB and Excel	Hour, 10 years	2050	Fixed (27 countries in Europe and 4 North African countries)	DC OPF	PHS	(Zani, 2011)
URBS	Deterministic	LP	Python	Hour (for user-defined weeks in a year), Annual	2050	Multiregional (has been adapted for Asia, Europe and Middle East North Africa)	NTC	All Technologi es	(Institute for Renewable and Sustainable Energy

									Systems, 2021)
PLEXOS	Stochastic and deterministic	Either MIP, dynamic or rounded relaxation programming	Stand-alone software based on GAMS solved by AMMO, Various Solvers	One hour up to one minute (for the whole year), days, weeks, months, years, user defined	User Defined	Multiregional (has been adapted for Asia, Australia, Europe, North America, South America and Sub-Sahara Africa)	AC OPF DC OPF Linearised approximation, NTC, SCOPF, FBMC	All Technologies	(Energy Exemplar, 2019)

2.2.2 Spatial and temporal representation

In specific electricity models, time-steps are fixed, while in others, the input data gives the time-step (Ringkjøb, Haugan and Solbrekke, 2018). For capturing the techno-economic dynamics of variable RES, a high granularity time step (at least hourly) and a long period of weather data are required. In case wind energy integration exceeds certain levels (60-70%), or energy storage and grid-balancing services are included, sub-hourly dispatch time-steps are advised for more robust unit commitment simulation, especially for precise cost estimation (Deane, Drayton and Gallachóir, 2014). For power system analyses, the time-steps might lower to milliseconds (Ringkjøb, Haugan and Solbrekke, 2018). The best results may be obtained when a variable time-step is employed, for example, when differentiating between weekdays, weekends or holidays. The increased temporal representation can also assist in precisely capturing the impact of RES in reducing carbon emissions. Most of the electricity models identified in the literature encompass only CO_2 emissions, while only PLEXOS and MESEDES are flexible enough to cover all types of GHG pollutants (Unsihuay-vila et al., 2011; Energy Exemplar, 2019).

The projection horizon for dispatch models is usually a year and is mainly run with an hourly time-step, although specific models carry out their hourly optimization weekly due to computational limitations (Smart Electricity Systems Research Group, 2012; EnergyPLAN, 2013). The long-term planning horizon in investment decisions and integrated models considering new units built is primarily up to 2050, although recent studies have extended the horizon beyond (Potsdam Institute for Climate Change, 2017; Spalding-Fecher *et al.*, 2017). Optimization of investments in generation, transmission and storage infrastructures usually takes single or multi-year time steps. Such models usually divide the annual energy demand into seasonal (quarterly, monthly, weekly) and time-of-day time-slices. Time-slices allow looking into how energy demand and supply vary compared to the annual calculations[12].

In models employing long-term planning horizons, challenges are linked to the uncertainty of economy and policy dimensions, usually tackled by various scenarios

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[12] https://leap.sei.org/help/Supporting_Screens/Time_Slices.htm

through sensitivity analysis. Long-term horizons also manage to address the usually shorter investment cycles of RES. Integrated models, despite requiring longer computation times, have the advantage of simultaneously optimizing the network's operation with hourly time steps while also optimizing investments, which has been the main objective.

To reduce computation time and still account for intermittent supply and seasonal demand, the E2M2s model proposes a 2-hour time step for 12 days a year (Swider and Weber, 2007; Spiecker, Vogel and Weber, 2013). ATLANTIS model, which has over 2400 nodes, has a monthly time step, with each month having two peak and off-peak periods (Stigler *et al.*, 2015), while ELMOD, with over 2000 nodes, has a 1-hour time step for a total of 24 hours in a year (Leuthold, Weigt and Hirschhausen, 2012). EMPIRE model has a 1-hour time step for 48 hours in 4 regular seasons and 5 hours in 3 extreme load seasons (Skar, Doorman, Guidatic, *et al.*, 2016). LIMES has a 6-hour time step for 4 times slices in 12 days of the year (Skar, Doorman, Pérez-Valdés, *et al.*, 2016). URBS, a multi-nodal model that divides countries into regions, has a 1-hour time step for user-defined representative weeks in the year (Institute for Renewable and Sustainable Energy Systems, 2021). EnaPLAN, PLEXOS and TEPES offer various high temporal resolution short-term time-steps ranging from a few minutes to one hour, while TEPES provides similar flexibilities but with (Universidad Pontificia Comillas, 2015; Energynautics, 2016; Energy Exemplar, 2019).

The hourly output of intermittent renewable energy plants like solar and particularly wind have been modelled using either a deterministic or stochastic approach. By using a deterministic approach, models consider the intermittent nature of the RES in a definite manner over a period, based on the historical generation and metrological data, power curves and capacity factors of renewable power plants. This method considers the RES intermittency; however, it does not encounter electricity generation uncertainty due to weather forecast changes which impact the dispatch and planning of infrastructures, sometimes leading to overestimates in the potential electricity generation from RES.

The increasing requirement to capture the uncertainty of intermittent sources and other risks leads several electricity models to incorporate stochastic modelling approaches facilitating the incorporation analysis of various scenarios. This stochastic approach considers the uncertainty of load profiles, wind speed, solar irradiance and water inflow in determining the hourly output of wind, solar and hydropower plants, respectively (Skar, Doorman, Pérez-Valdés, et al., 2016). In the context of integrating intermittent RES into interconnected electricity networks, the stochastic methodology enables analysis of the impact of these uncertainties on the system's costs, investments in conventional power plants, interconnection lines, storage and reserves in the networks.

Several modelling methods determine the hourly output of wind plants by using published historical wind speed data with power curves of W/Ts manufacturers (Sensfuß and Genoese, 2002; Richter, 2011; Zickfeld *et al.*, 2012; Nahmmacher, Schmid and Knopf, 2014; Simlab, 2017; Child *et al.*, 2019; Institute for Renewable and Sustainable Energy Systems, 2021). The wind power curve shows the relationship between turbine height, wind speed and electricity generation of a certain W/T. However, given that wind speed continuously varies at different spatial resolutions and turbine heights, the estimated hourly profiles usually do not capture in detail wind power generation resulting in electricity generation disparities. In some cases, models treat renewable energy generation as an exogenous input considering only historical capacity factors. ATLANTIS and MTSIM use average monthly and seasonal generation profiles for wind plants (Zani, 2011; Stigler *et al.*, 2015).

The hourly output of solar PV plants in a number of studies is calculated based on Global Horizontal Irradiance (GHI) that falls on the PV cells, with the optimal inclination and tracking of the PV taken into consideration (Richter, 2011; Zani, 2011; Nahmmacher, Schmid and Knopf, 2014; Simlab, 2017; Child *et al.*, 2019). EUPower Dispatch uses the PVGIS methodology, which in addition to GHI, also takes into account sky obstructions by hills or mountains in determining the hourly output of PV plants (Brancucci Martínez-Anido *et al.*, 2013). In other models, the modelling of run-of-river and reservoir hydro output is based on capacity factors for different seasons.

The spatial resolution of electricity models identified in the literature used to analyse the planning and operation of interconnected electricity networks with the integration of intermittent RES varies from low resolution to medium resolution and high resolution. The majority of the integrated models and some dispatch models, such as EuroDys, EUPower Dispatch and METIS (Smart Electricity Systems Research Group, 2012; Spataru and Barrett, 2012; European Commission, 2021b), have low spatial resolution and represent regions such as countries or islands or group of regions as nodes. Generation plants are aggregated by fuel type, and the internal transmission network between countries is not included in the model. The interconnection transmission lines between countries are also aggregated by their net transfer capacities for those models.

In an effort to represent the varying nature of renewable energy sources in different locations within a country and sometimes model power flows between countries, investment models and a few dispatch and integrated models divide regions into sub-regions (Weber *et al.*, 2009; Richter, 2011; EnergyPLAN, 2013; SINTEF, 2014; Fraunhofer ISE, 2016; Skar, Doorman, Pérez-Valdés, *et al.*, 2016; RWTH Aachen University, 2018; Child *et al.*, 2019; Institute for Renewable and Sustainable Energy Systems, 2021). Dividing the regions into sub-regions can be based on demand locations, sites of renewable energy sources and the different transmission operators. Highly spatial models such as EnaPLAN, TEPES, ATLANTIS and more (Zani, 2011; Leuthold, Weigt and Hirschhausen, 2012; EnergyPLAN, 2013; Stigler *et al.*, 2015; Universidad Pontificia Comillas, 2015; Energynautics, 2016; Simlab, 2017; Energy Exemplar, 2019) can simulate all the generating power plants and high voltage transmission lines in the region. Given these models' comprehensive modelling of high voltage transmission networks, a detailed analysis of power flow and congestion management can be carried out. Usually, models created for wider commercial or academic use, such as PLEXOS, URBS, WILMAR, EMCAS and others, include flexible geographical configuration and have already been adapted for different regions worldwide.

To conclude, the literature review suggests that optimisation models providing high spatio-temporal resolution with increased flexibility to incorporate stochasticity in conjunction with long and short-term projection horizons can capture the peculiarities of electricity systems, including small isolated systems' operation such as islands. These methods enhance modelling accuracy concerning geographical and power generation diversification and are subject to vulnerabilities of future policies and techno-economic parameters.

2.2.3 Transmission extensions

Electricity interconnections between regions such as islands or countries play a key role in designing the future electricity system. They facilitate the integration of high amounts of RES generation scattered between regions. In parallel, they contribute to the smooth power supply and cost reduction, which are the main objectives of this thesis. Additionally, transmission networks enable large-scale electricity trading while integrating new markets. In particular, the importance of transmission extensions increases when the examined region represents islands or island complexes, considering their peculiarity in energy isolation and dependence on neighbouring regions. Therefore, a detailed representation of the transmission system in parallel with the generation, consumption and storage capacities is important in order to capture the fluctuations of power production and allow for better load distribution and limited grid congestions (Spiecker and Weber, 2014; Scholz *et al.*, 2017).

Transmission grids are usually modelled through the Alternative Current Optimal Power Flow (AC-OPF) method (Carpentier, 1962). The DC optimal power flow method (DC-OPF) (Alsac *et al.*, 1990), in which the AC-OPF problem is linearised by assuming simplifying assumptions, is considered a prominent option; however, with less accuracy. The main differences between these two methods are summarized in the approximations of the DC-OPF regarding the exclusion of reactive power balance equations. Hence losses are not incorporated, assuming all voltage magnitudes are equal per unit. Finally, the dependence is overlooked in the transformer reactance, also not covered by the generation units (Overbye, Cheng and Sun, 2004; Sayfutdinov *et al.*, 2020). The solution to a DC-OPF problem could lead to results in the same order of magnitude as the AC-OPF in two bus systems or similar. However, the DC-OPF leads to differentiated discrepancies according to the simulated system (Chamanbaz, Dabbene and Lagoa, 2017).

Although several models identified in the literature carry out DC optimal power calculation, aggregated interconnection lines are usually represented as transport models with the line's reactance and resistance characteristics not accounted for in the model (Table 2.1). This simplification is performed through the net transfer capacities (NTC) approach, which models power flows controllably, similar to a transport model. A transport model calculates power flows as the margin between the total transfer capacity and the transmission reliability margin (ENTSO-E, 2017). One of the reasons NTC is employed is the difficulty of obtaining all the technical and economic data for the high voltage transmission lines and generation plants in each country. Even when this data is available, the computation time required to run such a detailed model is usually too long. Other approximations could be the unrestricted copper plate transmission assumption, ignoring grid costs on lower voltage levels (Scholz *et al.*, 2017).

Studies have been extensively published to investigate the economic impact of extending interconnections between regions and increasing electricity trade. Cosmo, Bertsch and Deane (2016) examined the effects of interconnectors' investments on welfare using PLEXOS. They concluded that overall new interconnectors in Europe result in welfare gains. Schaber, Steinke and Hamacher (2012) developed the URBS-EU model for 83 regions in Europe and suggested that there would be economic benefits for intermittent RES owners' plants due to the increase in incomes from the grid extensions. However, owners of conventional plants used for baseload to the fluctuating RES supply would only benefit if they are located close to an intermittent RES plant with a substantial capacity. Spiecker, Vogel and Weber (2013) used E2M2s in their study and concluded that extensions in the North European grid would increase the region's total welfare gains. Huber, Dorfner and Hamacher (2012) adapted the URBS model for 30 countries in Europe and eight in the Middle East and North Africa (MENA). They concluded that the total system cost of an integrated electricity network between Europe and MENA was always lower than separate Europe and MENA systems with no electricity exchanges. Similarly, Zickfeld *et al.* (2012) investigated Europe importing 20% of its electricity from RES in MENA using PowerAce, and claims a potential saving of 33€ billion annually. Despite comprehensive macro-economic assessments of international electricity trade being outside this research's scope, learnings from the previous studies show that long-term investments in transmission extensions may positively impact total system costs with economic benefits for producers, operators and consumers, notwithstanding the intensive capital investments which they necessitate.

2.2.4 Energy storage

Extensions to interconnections have faced substantial delays due to complex processes and many stakeholders involved in the planning and installation process. Some proposed interconnections also face cancellations because of the public’s resistance to grid extensions that can adversely impact their health, properties, and environment. Given these challenges, most of the models presented in Table 2.1 encompass the option to simulate electricity storage systems, while specific dispatch models such as DIETER have been developed mainly to capture the EES role (DIW Berlin, 2017). Today's most widely available storage technology is PHS; therefore, for certain models, the available options are limited to that technology (Leuthold, Weigt and Hirschhausen, 2012; SINTEF, 2014). For example, the EMPS, which considers PHS exclusively, has developed a sophisticated approach for modelling pumped hydro by calculating water values and targeting reservoirs per week (Graabak *et al.*, 2017). Due to the limitations for further expansion of pumped hydro systems, the majority extend their simulation options to CAES, thermal energy storage, BESS, and hydrogen technologies, at least at the European level. Each storage option is introduced in the model through specific objects with unique characteristics representing the technology's specificities. Alternatively, they are simulated by adapting the existing features of the model or mimicking the energy storage functions BESS is usually represented as a generator that can absorb and store power given its capacity. This is the case for PLEXOS and METIS models (Kanellopoulos, 2018; Energy Exemplar, 2019), where batteries are objects connected to the rest of the system considering the bus they are assigned to with all the techno-economic features that accompany such systems. In EnerPol, batteries are modelled as an AC multi-period optimal power flows (MOPF) simulation with N time steps (Joubert, Chokani and Abhari, 2018).

Several case studies have been applied to examine how storage could substitute the need for interconnections' extensions to integrate large amounts of intermittent RES. Verzijlbergh et al. (2014) used EUPowerDispatch and showed that EVs could perform both as an alternative and complement cross-border transmission under a high RES scenario. Strbac et al. (2012) used DSIM in evaluating the economic benefits of grid-scale electricity storage in the UK while taking interconnections with neighbouring countries into consideration. Graabak et al. (2017) used EMPS to model the Norwegian power sector with increased hydropower operation in relation to the EU electricity system. Cleary *et al.* (2016) used PLEXOS to present the economic benefits of CAES in different wind energy integration scenarios in the 2020 Ireland electricity system while taking interconnections with Britain into consideration. PLEXOS is also used for North-Western Europe by Deane (2015) to optimise pumped storage when integrating electricity generated from RES by 2050, demonstrating low capacity factors across Europe. Results from the Europe PowerAce model in Pfluger and Wietschel (2012) indicate that large storage infrastructures will be economical only in scenarios of a high share of intermittent RE in the electricity mix. Similarly, Frazier *et al.* (2020), using PLEXOS, showed a strong correlation between wind, solar and BESS, as RES integration leads to higher batteries deployment levels. Batteries impact the net load distribution, which defines the total efficiency of storage as a peaking capacity resource. Joubert, Chokani and Abhari (2018) employed EnerPol to prove that the overall cost of electricity, including renewables curtailment, drops by introducing BESS in the European transmission grid by 2030. It is also proved that the optimal utilisation of batteries is highly dependent on the integration level and their geographic location.

METIS was used in a study conducted on behalf of JRC by Kanellopoulos (2018) to analyse future scenarios for Europe in the post-coal era. The study showed that BESS have considerable potential for deployment in the EU electricity system ranging between 13 and 19 GW subject to the economics of the technology and the phase-out of old lignite stations. On the contrary, while using the EMPIRE model, Skar, Egging and Tomasgard, (2016) suggest that storage is an expensive substitute to interconnections when there is high integration of RES in the European electricity system. This inconsistency can be attributed to the BESS cost assumptions as well as the way RES and load are treated, as stochastic investment optimization considers the uncertainty of intermittent RES and thus results in lower investment costs for interconnections. This analysis stressed the importance of employing storage simulation within the optimisation model under a high-RES share environment similar to the future Greek islands . Most case studies emphasise ESS economic benefits; however, costs in relation to the siting and sizing and the operational conditions of the ESS play a critical role in defining the system configuration.

Overall, the modelling review highlighted strengths and weaknesses among electricity optimisation models. Certain ones, due to their flexible modelling features and high spatial and temporal resolution, such as PLEXOS, emerged as highly suitable to simulate and optimise future islands interconnections and storage systems under high-RES shares. Despite the extended literature covered in the next section, including the Greek islands case studies, the use of PLEXOS, a commercial tool, in this context constitutes a ‘first of its kind’ approach, as further explained in section 2.6.

2.3 Modelling islands' electricity systems

Peer review literature and relevant techno-economic studies diversify based on the following qualities: geographical scope, spatial and temporal resolution, simulation period, energy technologies, assumptions, and methodologies. This section discusses and categorises research conducted on the Greek islands region concerning: I) Interconnections between the islands and the mainland (Section 2.3.1) or II) Autonomous operation supported by energy storage technologies (Section 2.3.2). Learnings from other case studies across the world are presented in Section 2.3.3

2.3.1 Modelling interconnections on the Greek islands

Investments in the Greek islands' infrastructure, including submarine interconnections, were not a priority in the national agenda for many decades due to the absence of a robust decarbonisation policy framework combined with increased upfront costs. Accordingly, the scientific community has explored alternative solutions concerning submarine transmission extensions between the Greek islands and the mainland, as presented in Table 2.2. Such projects assessed individual power transmission links between regions or single islands and the mainland, while rarely have encompassed an overarching plan for the Greek islands region's interconnection.

The largest body of the literature has analysed long-term assessments via scenarios. The majority of these state-of-the-art analyses assume DC technology for modelling the interconnections. Although the methods employed vary, these studies have been grouped under the ‘Investment Modelling Approaches’ category. They all investigate the techno-economic impact of future interconnections versus the autonomous operation through transmission and generation expansion.

The Northern Aegean Sea islands interconnection was examined by Papadopoulos *et al.* (2007), showing that it is feasible to reach 100% of RES penetration if they connect to the national grid system. In the same study, Crete's interconnection was assessed using a probabilistic approach, showing that the economic benefits of its interconnection are validated in parallel with wind energy development. They also demonstrated the IPTOs initial plan for interconnecting Crete with 2* 350 MW cables which could only meet baseload demand. Crete’s interconnection was also examined by Loukarakis *et al.* (2011). The authors explore various investment options through Monte-Carlo probabilistic assessment, showing that a 2* 300-350 MW DC transmission expansion option combined with the local grid's improvement in the western part of the island will lead to the optimal investment maximising the socio-economic benefit. Options for higher interconnection capacities exceeding 700 MW seem to present less attractive economic indices; however, the authors do not emphasise the island's simultaneous RES development, which could offset any additional upfront interconnection costs.

Future interconnection perspectives for the island of Crete are also explored by Menegatos (2015) through a techno-economic feasibility study. He showed that Crete's interconnection with an enhanced capacity of 2*500 MW proves to be even more economically efficient by 2€ billion, translated into a Levelised Cost of Energy (LCOE) reduction of 35% while it allows 20% higher RES penetration compared to the 700 MW case. The author proves that any interconnection scenario is more cost-efficient than continuing the existing energy autonomy. Along the same lines, Lesvos’ interconnection economic interest through an integrated theoretical model is highlighted by Kapsali, Kaldellis and Anagnostopoulos (2016). In particular, the authors argue that future interconnections full economic potential is realised only in parallel with rapid RES development reflected in the cost of the interconnection project, which could be reduced by 40%.

Karamanou, Papathanassiou and Papadopoulos (2008) present various interconnection alternatives, using both DC and AC technologies in contrast with autonomous operation. The analysis shows that the Greek islands' interconnection option is always the most profitable compared to the autonomous, reducing the net present worth of the associated costs up to 27%.

In Papadopoulos *et al.* (2005), three different scenarios for the Cycladic islands' electrification are presented as specified in National Technical

University of Athens (2008), concluding that the optimum solution is the construction of a new HV grid among the islands and the mainland. The results validate that the Cycladic islands' interconnection is feasible only if significant local renewable energy is deployed at the local level. While the majority of the studies approach the analysis from the central operator's point of view, another perspective from a RES investor is presented by Hatziargyriou *et al.* (2007). The authors conduct an investment analysis for wind energy development in the Cyclades area following their interconnection, considering the thermal limits and other environmental and site-specific restrictions. The main tools used are the GIS and the OPTIRES planning tool for the spatial analysis, while for the economic analysis, the OPTIRES profitability analysis module was employed. The study highlights that the submarine cables' immersion would add significant value to the locally developed wind energy.

Georgiou, Mavrotas and Diakoulaki (2011) and Georgiou (2016) developed an expansion planning methodology using MIP. The islands and the respective interconnection DC capacity were clustered in groups, while an annual time step was adopted, with limited granularity in the spatio-temporal resolution. The modelling results proved that interconnections are cost-effective for the Greek power system, allowing RES penetration to reach 56% at a national level by 2024, almost 20% more compared to the current levels. The interconnection project favouring most of the Greek mainland in terms of exports is mainly the one involving the Cyclades and Northern Aegean islands, while on Crete and Dodecanese, the local RES generation is consumed locally.

In contrast with the previous studies, Kasselouri *et al.* (2011), through a 2030 projection exploring mainly the socio-economic impact of three different scenarios, concludes that the most efficient scenario in terms of the socio-economic dimensions is the installation of WPHS for the Aegean Sea Region. Transmission expansion should be limited only to the Cycladic islands. The investment appetite could explain this conclusion for RES under the interconnection scenario, which is limited to publicly available data. Similarly, Xydis (2013), using LP, compares an autonomous grid with high penetration of hydropower, onshore and offshore wind, and other renewables with medium-term energy storage to transform wind energy into a baseload and diesel generators to a peak-load resource. The author suggests that such a system can be more economically efficient and reach higher RES penetration levels than a so-called ‘super grid’ between the Greek mainland and the islands. On the other hand, such an interconnected system could benefit from exports and imports from areas with different meteorological characteristics.

The Greek islands' interconnection was also simulated on a short-term basis through ‘Dispatch Modelling Approaches’ to identify the operational schedule and marginal prices' impact at the local and national levels via optimal power flows between the regions. A generic Mid-term Energy Planning Model has been incorporated together with a unit commitment model in MIP that has been proposed by Koltsaklis *et al.* (2016). The model uses an hourly scheduling period to provide optimal solutions regarding the yearly energy balance and the viability of Crete’s interconnection. It confirms via six scenarios that marginal prices are reduced on the island when combined with RES integration, which defines the economic feasibility of Crete’s interconnection with the mainland. A detailed configuration of the future interconnections was published for the first time by the IPTO and HEDNO (Karystianos *et al.*, 2021) until 2050. The authors proved that Northeast Aegean and Dodecanese Islands could be interconnected exclusively with at least 150 kV interconnectors through two main scenarios. Also, they showed that Crete–Dodecanese interconnection is possible under certain topologies. According to the static security analysis, the reliable electricity supply requires maintaining some local reserves on Rhodes, Chios and Samos islands in cold reserve status. From an economic point of view, the total CAPEX of the interconnection projects is equal to approximately 2.3€ billion and the LCOE to approximately 211 €/MWh.

Lignos and Tsikalakis (2015) presented an alternative interconnection study between Thera and Crete islands by optimizing future generation mix, power flows, losses and costs by considering four different interconnection options under a unit commitment optimization problem. The simulation has been performed with the PowerWorld® Software. The dispatch profiles show that Crete's wind power curtailment can be reduced by 74%, leading to a gradual reduction of expensive power generation on Thera Island. Antoniou *et al.* (2013) applied the same concept to evaluate Crete's interconnection with Cyprus as part of the Euro-Asia interconnector. While applying economic operation scheduling, power flows between the two islands and the units' production, including intermediate, peak-load units and RES generation, are calculated. The study highlights that Crete will benefit economically and environmentally as part of the thermal generation will be displaced to Cyprus. On the other hand, a small margin for synergies is recorded as Cyprus', and Crete's load profiles are synchronised leading to no positive effect in curtailments reduction and RES penetration.

Grid power system analysis and dynamic security assessment, incorporating detailed modelling of the transmission extensions, power flows, short-circuit analyses, stability etc., has been covered by studies in the literature. Papadopoulos and Papageorgiou (2004) present the technologies available to interconnect the Greek islands with AC cables without detailed simulation or comparative analysis. In contrast, Nanou, Papathanassiou and Papadopoulos (2014b) exhaustively analyse the advantages and drawbacks of HV AC and DC. Nanou, Tzortzopoulos and Papathanassiou (2016) utilise the DC voltage droop control method to attain distributed DC voltage control of the network. The optimization problem is formulated, assessing its effectiveness by using the Monte-Carlo simulation. A steady-state analysis is extensively covered, considering DC voltage, active power variations and steady-state variations of multi-terminal DC grid system losses. Loukarakis (2012) also applied steady-state analysis in DC interconnections for the island of Crete. The stability of Crete's interconnection under operational conditions is evaluated by Karystianos, Kabouris and Koronides (2014). It is concluded that specific thermal units should continue operating even following the interconnection due to their importance in the system's static and dynamic security. Nevertheless, the HV DC links will provide most of the required reserves, as the existing thermal units are of slower response.

Table 2.2: Literature on submarine transmission extensions for the Greek islands

Methodology /Tool	**Spatial Resolution**	**Temporal Resolution**	**Timeframe**	**Reference**
Investment Modelling				
Probabilistic (Logistic Model)	Crete	Annual	2010-2035	(Papadopoulos *et al.*, 2007)
Techno-economic Analysis	Crete	Annual	2015-2040	(Menegatos, 2015)
	Greek islands region	Annual	25 years	(Karamanou, Papathanassiou and Papadopoulos, 2008)
	Lesvos	5 years	2020-2045	(Kapsali, Kaldellis and Anagnostopoulos, 2016)
Monte Carlo	Crete	Annual	-	(Loukarakis *et al.*, 2011)
Forecasting Modelling (ARIMA)	Greek islands region	Annual	2010-2030	(Kasselouri *et al.*, 2011)
MIP		Annual	2009-2020	(Georgiou, Mavrotas and Diakoulaki, 2011), (Georgiou, 2016)
LP	North Aegean Islands	-	-	(Xydis, 2013)
Dispatch Modelling				

MIP	Crete	Hour, Annual	2016	(Koltsaklis *et al.*, 2016)
Unit commitment optimization (sequential quadratic programming), **Transmission Expansion (PowerWorld simulator),** **Forecasting errors (probabilistic technic)**	Crete, Thera	Duration curve	2010	(Lignos and Tsikalakis, 2015)
	Crete, Cyprus	Duration curve	2010	(Antoniou *et al.*, 2013)
Static Security Analysis, **Unit commitment optimization,** **Economic Assessment,** **OPF**	Greek islands region	Hour	2025-2050	(Karystianos *et al.*, 2021)
Dynamic Security Assessment				
Non-sequential Monte-Carlo method	Crete	-	-	(Loukarakis, 2012)
Load Flow, Dynamic model using PSS/E simulator		Mili-seconds	2012	(Karystianos, Kabouris and Koronides, 2014)
Descriptive	Cycladic islands	Seconds	2005-2030	(Papadopoulos and Papageorgiou, 2004)

	Greek islands region	Seconds	-	(Nanou, Papathanassiou and Papadopoulos, 2014)
Optimisation using genetic algorithms (GAs) in Matlab, Monte Carlo, OPF	North Aegean Sea islands	Seconds	-	(Nanou, Tzortzopoulos and Papathanassiou, 2016)

The literature review shows that most of the studies have been covered by custom made methodological approaches while no commercial optimisation model such as PLEXOS has been tested in this context. Under most interconnection scenarios, transmission infrastructure extensions reduce generation costs in island systems. One of the most critical conclusions concerns the direct dependency of interconnections feasibility with the parallel deployment of RES on islands. Despite the extensive assessment of the economic impact of RES deployment on island systems, the lack of inclusive approaches concerning the impact on the NGS undermines the quality of the analysis conducted regarding the environmental impact. In terms of security of supply, there is a lack of comprehensive analysis considering capacity reserve mechanisms and ancillary services. At the same time, the majority of the studies show that certain thermal capacity has to be maintained to ensure a smooth power supply, especially considering medium and large-sized islands.

2.3.2 Modelling energy storage on the Greek islands

Due to the increased costs and technical challenges associated often with submarine interconnections, significant research concerning the dimensioning and sitting of energy storage systems that could reduce oil-fuel dependence on the Greek islands has been conducted. The technologies employed are principally dependent on their commercialised readiness and economic potential. The geographical scope is usually one or more islands distant from the mainland shore. The temporal resolution varies from a few minutes to years, with the most common time-step being hourly with a timeframe of one year.

The literature primarily conducted before 2016 was split into two categories, as indicated in Table 2.3. The first group includes studies where the size and other ESS features are a product of optimisation analysis or parametrical investigation. The second category comprises studies taking as a modelling input the size and the type of the hybrid system while exploring its operational techno-economic impact on the island systems. A large body analysed wind and hydro pump systems' potential for various insular systems in Greece. These studies considered the island's load as critical parameters, the existing wind energy potential, electricity costs, and the power system configuration where the WPHS will be deployed. A specific operational schedule in the form of an algorithm/flow-chart is usually employed to indicate when electricity will be dispatched from the hydro-pump system or, respectively, the periods when there will be a need to withdraw power for charging.

Caralis, Rados and Zervos (2010) showed that the required cost to develop wind coupled with pumped storage on the Greek islands is competitive compared to the oil fuel costs. A parameterisation for different sizes of the WPHS system proved that wind and hydro could eventually cover 64% of the region's power demand. Similarly, Anagnostopoulos and Papantonis (2012) optimise the sizing and design of a pumping station on Crete while increasing the amount of wind energy generated to be transformed into hydraulic energy. The authors proved that a 500 MW wind hydropower plant could offset a thermal power plant of 170 MW capacity. Certain studies, such as Katsaprakakis *et al.* (2012), have been less ambitious in terms of the size of the ESS by employing one WPHS project on Karpathos island, which shows that the configuration allows maximum wind share penetration up to 23% and a capacity factor of 52%.

Katsaprakakis and Christakis (2009) proved that RES penetration to medium and large-sized systems such as Crete, Rhodes and Lesvos under exceptional weather conditions could scale up to 90%, which would force thermal electricity generation limitations. In smaller systems (Kasos – Karpathos, Astypalaia), the maximum penetration is 80% of the annual electricity demand. Kaldellis (2002) confirms this approach, showing that larger islands exhibit an energy efficiency advantage compared to smaller ones for similar wind speeds, while small systems reach higher RES penetration values. Both analyses highlighted that despite the lower costs per unit of capacity in large-sized systems, their size and complex system configurations place many techno-economic threats. Implemented projects showcase that the gradual replacement of thermal generators by WPHS systems is realistic. The recently completed hybrid project in Ikaria was evaluated by Papaefthymiou *et al.* (2010), proving that a 5.2 MW of a pumped-hydro system could increase RES penetration by 50%.

Dynamic performance and stability of island power systems incorporating wind and hydro were investigated by Brown, Peças Lopes and Matos (2008); Katsaprakakis and Christakis (2009); Karapidakis *et al.* (2014); Sakellaridis *et al.* (2014). The research proves that security criteria provide the economic incentive for installing such systems. The results show that the islands' system frequency stability is enhanced when PHS are deployed. They could be combined with additional system measures, control enhancement, and other preventive actions if required. The positive effect of PHS is demonstrated through the enhanced frequency response profile and the reduced load shedding events. The actual operation of such systems within the local market has been optimised by Ntomaris, Vagropoulos and Bakirtzis (2015) using MIP. Day-ahead scheduling under different scenarios shows more than a 10% reduction of Crete's annual total costs for an ambitious scenario introducing a PHS of 120 MW.

Beyond wind coupled with hydro pump systems, comparative research has been conducted for other ESS regarding their applicability to AES. Small island systems with a peak electricity demand of less than 1 MW have been extensively coved by the literature. The integration of a hybrid system comprising W/Ts (300 kW), solar PV (200 kW), BESS (32 batteries of 96 V) and a biogas system (60 kW) has been explored by Kaldellis *et al.* (2012) on the tiny island of Agathonisi. The authors proved using the HOMER model[13] that such a diverse energy portfolio mix could meet the island's energy and water needs. Similarly, a BEES installed on Donousa island has been examined by Papastamoulos *et al.* (2014) while developing a simulation model in MATLAB under three different operating policies. The system consists of 330 kW W/Ts, 700 kWh Lead-Acid batteries and a 300 kVA inverter. The analysis showed that a 70% integration of RES could be achieved.

An alternative for securing a clean energy supply for the island of Megisti, the easterly Greek and EU edge, is investigated in Kavadias *et al.* (2017), proposing a PV – Na-S BESS configuration. The study applies a parametrical investigation and highlights that the PV component is not the most critical cost for lower autonomy values. Finally, the analysis suggests 24 hours of autonomy with a larger than 1.47 MW PV system as a cost-optimal solution. Three small islands in the Cycladic region: Sifnos, Serifos and Astypalaia, prove to have the suitable size and electricity load profiles to host wind-battery systems according to Pligoropoulos *et al.* (2013) through PowerFactoryTM (DigSILENT) model[14]. The study was limited to increasing wind potential by up to 30% in the three islands.

The economics of battery hybrid systems on islands is crucial for their feasibility during their life cycle. For that reason, a sizing methodology was developed by Kaldellis *et al.* (2009) and tested on three islands: Rhodes and two interconnected islands Thasos and Zakynthos. A PV battery system will prevail against a diesel-electric generator as the energy requirements of the latter are at least one order higher than those of the PV and battery system. The benefits of synergies between BESS, RES and interconnections are investigated for the first time by Kougias *et al.* (2019). Through a cost optimisation approach using a 'Harmony Search Algorithm', the paper explores the opportunity for installing such systems on Rhodes, Lesvos, Chios,

[13] https://www.homerenergy.com/

[14] https://www.digsilent.de/en/powerfactory.html

Karpathos and Patmos islands. The results prove that in order to reach at least 50% of RES penetration, ESS with autonomy at the order of magnitude of 12 to 15 hours should be installed to replace a significant quantity (70-80%) of their oil-fired generation. They also show that larger islands require less autonomy due to higher thermal generation stock flexibilities.

Beyond commercialized mature technologies, FCH solutions seem to be a promising alternative for islands' applications, with many studies looking into dimensioning and simulating such systems. In particular, Kyriakidis, Braun and Chaudhary (2012) explore the operation of a hybrid battery-solar-wind system complemented with an electrolyser, using hydrogen as a fuel for the island of Agios Efstratios in the Northern Aegean Sea. The authors investigated a vast number of scenarios that proved that the maximum penetration of RES under an economically feasible scenario would be 94.6% and not 100% due to the relatively low-RES potential combined with high demand loads over the summer months triggering the dispatch of the diesel engines. The seasonality was also emerged by Thomas, Deblecker and Ioakimidis (2016), proposing to install a PV, wind and BESS for Agios Efstratios. The authors claimed that the maximum penetration following an optimization with HOMER is 74% considering only economically feasible solutions. Ntziachristos *et al.* (2005) proposed a hybrid system consisting of a wind turbine and an FCH system for Karpathos, showing that the FC optimal sizing should be at 34% of the W/T. A Wind-PV-batteries-FCH system and a WPHS are employed by Katsaprakakis (2016). The system's dimensioning and operation are identified based on two key criteria: to maximise RES integration and optimise the economic indicators. The study highlights the superiority of lead-acid batteries applicable to islands of different sizes due to their scalability and modularity. At the same time, WPHS can be introduced to an AES with an annual peak power demand of a minimum of 2–3 MW.

Kaldellis and Zafirakis (2007) investigated a set of options for the Greek islands, considering two representative islands Lesvos (medium-sized) and Donousa (very small). The study shows that FCH systems require high autonomy to become efficient, but they are highly suitable for applications on islands. Na-S could also be installed when lower autonomy is required, while Regenesys has a competitive advantage for higher autonomy. CAES may be considered only in low autonomy, e.g., 2 hours, when CAES peaking demand services appear to be almost 20% and 50% cheaper in terms of LCOE compared with PHS and BESS, respectively (Caralis *et al.*, 2019). For Donousa island, Na-S batteries seem to outweigh the rest of the technologies, while for larger islands, both PHS and Na-S batteries are the cost-optimal option reducing the annual operating costs by 7.5% while simultaneously increasing wind penetration on Samos, according to Katsigiannis and Karapidakis (2017).

Overall, the results proved that the local renewable energy potential and the size of the storage system, including the energy pricing, play an essential role in achieving energy autonomy on islands while reducing costs compared to the existing conditions. Nevertheless, the environmental and land footprint impacts were not emphasized as critical criteria for such systems.

Table 2.3: Literature on energy storage systems analysis for the Greek islands

Methodology/ Tool	**Storage Technologies**	**Spatial Resolution**	**Temporal Resolution**	**Timeframe**	**Reference**
Sitting & Sizing ESS					
Parameterised Diagrams	WPHS	Greek islands' region	Annual	-	(Caralis, Rados and Zervos, 2010)
Optimisation based on in-house computational modelling		Crete	Hour/10 minute	One year (2015)	(Anagnostopoulos and Papantonis, 2012)
Engineering & Techno-		Crete, Rhodes and Lesvos, Kasos-	Hour	One year	(Katsaprakakis and Christakis, 2009)

economic analysis		Karpathos, Astypalaia			
		Kythnos, Karpathos, Ikaria	Hour	One year (2000)	(Kaldellis, 2002)
		Kasos-Karpathos	Hour	One year (2008)	(Katsaprakakis *et al.*, 2012)
Time-series-based simulation model		Ikaria	Hour	One year (2012)	(Papaefthymiou *et al.*, 2010)
HOMER	PV, Wind, Biogas, battery	Agathonisi	Hour/Month	Multiple years (1996 - 2028)	(Kaldellis *et al.*, 2012)
HOMER, Logistic Modelling in Matlab7	Wind and battery	Donousa	Hour	One year 20 years (2012)	(Papastamoulos *et al.*, 2014)
Engineering & Techno-economic analysis	Wind, PV, battery	Megisti	Hour	20 years	(Kavadias *et al.*, 2017)
HOMER		Agios Efstratios	Hour	One year (2010)	(Thomas, Deblecker and Ioakimidis, 2016)
Computational Algorithm PHOTOV-III	PV, battery	Thasos, Zakynthos, Rhodes	Hour	One year	(Kaldellis *et al.*, 2009)
PowerFactoryTM (DigSILENT)	Wind, PV, battery	Sifnos, Serifos, Asyipalaia	-	Two years 2004 2010	(Pligoropoulos *et al.*, 2013)

Energy Management, Control Algorithm Matlab/Simulink	Wind, PV, battery, H_2	Agios Efstratios	Hour	One year	(Kyriakidis, Braun and Chaudhary, 2012)
Engineering Analysis	Wind, H2	Karpathos	Hour	One year	(Ntziachristos *et al.*, 2005)
Operation Algorithm	Wind, PV, PHS, batteries, H2	Crete, Rhodes, Samos, Karpathos-Kasos, Astypalaia, Kastelorizo, Agios Efstratios	Hour	One year (various reference years)	(Katsaprakakis, 2016)
Engineering & Techno-economic analysis	Wind, PV, PHS, CAES, regenesys, Na-S, Lead Acid batteries	Lesvos, Donousa	Hour	Multiple years	(Kaldellis and Zafirakis, 2007)
OPF, Matlab	Wind, Na-S batteries	Samos	Hour	One year (2015)	(Katsigiannis and Karapidakis, 2017)
Engineering & Techno-economic analysis	Wind, PV, CAES, PHS, Na-S batteries	Crete	Hour	One year	(Caralis *et al.*, 2019)
Dynamic Performance					
Dynamic Security Assessment	WPHS	Crete, Rhodes and Lesvos,	Seconds	One year	(Katsaprakakis and

		Kasos-Karpathos, Astypalaia			Christakis, 2009)
Siemens PSS/E^{TM}	WPHS CSP	Crete	Seconds	-	(Sakellaridis *et al.*, 2014)
Power World Simulator	PV & WPHS	Crete	Seconds	-	(Karapidakis *et al.*, 2014)
Dispatch Modelling Approaches					
Mixed Integer Programming (MIP)	WPHS	Crete	Hour	One year (2013)	(Ntomaris, Vagropoulos and Bakirtzis, 2015)
Investment Modelling Approaches					
Harmony Search Optimisation Algorithm	PV, wind, batteries	Rhodes, Lesvos, Chios, Karpathos and Patmos	Annual	20 years (2016-2036)	(Kougias *et al.*, 2019)

The review highlights those technologies such as PHS, FCH and CAES do not appear to be constrained by the level of autonomy while exhibiting lower electricity costs for a higher annual contribution. The studies also conclude that the financial attractiveness of PHS is subject to their meteorological characteristics to accommodate a high-RES share. On the other hand, although BESS present lower costs per unit in low autonomy cases, they are impacted when autonomy increases considerably. Furthermore, their suitability to regulate the island’s demand profile requirements relevant to the available RES plays a catalytic role. These technologies are generally assessed at the autonomous state without considering the benefits of coupling storage with island interconnections.

2.3.3 Modelling interconnections and energy storage on other islands

The literature covers case studies considering island interconnections in the international context. The introduction of NG as a transition fuel in insular power systems has been a subject of research, from Crete to Tenerife. Ramos-Real *et al.* (2018)focus on the impact of introducing NG as fuel for Tenerife and show that its interconnection is economically profitable and environmentally sensible if NG covers a significant share of the electricity mix. Otherwise, the autonomous operation of La-Gomera coupled with BESS and RES generation is judged optimum. Two other Canary islands, Lanzarote-Fuerteventura, and Balearic Archipelago have been used as case studies by Lobato, Sigrist and Rouco (2017) through MIP simulation with an hourly unit commitment on a weekly time frame. The model analyses possible interconnection routes and emphasises critical reserve restraints. It concludes that the submarine cable contributes significantly to the upwards reserve in both islands, enabling the use of diesel generators more efficiently. However, each interconnector's profitability is highly dependent on the island systems' electricity generation mix and other characteristics.

The interconnection of Pico and Faial islands in the Azores Archipelago in Portugal has been analysed by Alves, Segurado and Costa (2019). The proposed scenario shows that the two islands could lift local RES penetration to 65.6% while employing BESS and a wide range of renewable energy sources. RES could go as high as 49.3% in the Autonomous Scenario, including BESS. Nevertheless, unlike most Greek case studies, the autonomous operation continuation is judged more profitable herein due to the submarine infrastructure's increased cost. Miranda de Loureiro (2017) investigates the interconnection of all Azores islands with a stochastic MIP model for transmission network expansion planning. The study proves that their interconnection will not coincide, impacted by the peculiarities of each island. Overall, the results show that an investment in underwater transmission, if technically feasible, will increase RES penetration by 3% in 2025, with further prospects for rapid development.

The positive impact of the Scottish islands' interconnection was examined by Matthew and Spataru (2021) with the use of the PLEXOS model. The model considers spatial diversification and forecasting errors by simulating day-ahead and intra-day markets. It was concluded that the Scottish islands' renewable capacity could support the stabilisation of RES in the UK concerning generation, prices and forecasting errors. The authors highlight that negative pricing often observed in the electricity market decreased due to geography and electricity supply diversity when combining different technologies with high potential, such as wind and marine.

The already implemented interconnection of Malta with Sicily is investigated in Ries, Gaudard and Romerio (2016). The study employed a MATLAB model that emulates the electricity generation dispatch under an autonomous and interconnected state. The results conclude that power generation costs are not reduced in Malta. Such infrastructure projects' success relies on the generation mix, fuel prices, and the liberalisation of energy utilities to drive down costs. The same interconnection but emphasising the Italian end is covered by Ippolito, Favuzza and Cassaro (2018). The study was carried out by the NEPLAN®[15] load flow tool, showing that when wind power generation increases, zonal prices reduce in Sicily. Compared to the previous case, this study showcases that Malta increases its reliability through its interconnection with the Italian system. However, the energy trading balance is not favouring the reduction of marginal prices due to the lack of a RES developmet plan. A significant conclusion regarding the importance of aligning RES deployment with submarine transmission extensions also for the Greek islands' region.

Concerning energy storage, a comprehensive review of ESS is presented by Groppi *et al.* (2021), exploring all the different energy storage options to support the local grid of islands across the world. The paper confirms that BESS seems suitable for small to medium-sized islands, while they could complement larger systems. A conclusion that confirms findings from the Greek literature as described before. On the other hand, PHS are especially

[15] https://www.neplan.ch/description/load-flow/

advantageous for larger systems with available natural reservoirs. In Spain, the case study of El Hierro was examined by Bueno and Carta (2005a, 2005b). The authors first developed a model to optimize various strategies for WPHS on islands showing that if 60 hours of energy autonomy is achieved through 10 W/Ts and 2 PHS, annual renewable energy penetration at a capacity level of at least 68.40% can be achieved on the island. The economics of PV-powered BESS in Madeira island in Portugal is assessed in Pereira and Cavaleiro (2020) concerning year-long simulations with a ten-year projection horizon, with the profitability of BESS beginning at 256 €/kWh, including the inverter. The authors concluded that despite the advantages of BESS for safeguarding electricity independence in AES, considerable drops in storage prices are still required to achieve profitability.

Singh et al. (2017) used PowerFactory6 (DigSILENT) for load flow analysis combined with the HOMER, a model used extensively for the Greek islands for long-term simulation modelling to emulate a solar-wind-battery system on the small island of Kavaratti in India. The cost-optimal system allows 4 hours of autonomy, reaching 26% of RES penetration, showing less ambitious RES share and lower autonomy levels compared to the Greek case studies. The model also indicates the battery's optimal location, considering the local power network configuration as an important dimension often neglected in the design of such systems. A different analysis by Ma, Yang and Lu (2014) also using HOMER shows that 100% RES penetration is achievable and economically feasible for a remote island with a much smoother seasonal demand profile if a PV-wind-battery system is employed. Nevertheless, to achieve the complete phase-out of diesel engines, the system must be oversized, dumping energy while overlooking the economic profitability. Similarly, the optimal sizing of BESS to support energy communities on islands is presented by Massaro, Pace and Sanseverino (2021). The case study of Pantelleria island in Italy is examined through a procedural nonlinear algorithm. The optimization suggests investing in community-owned BESS rather than customer-owned ones as every community member takes advantage of storage capacity and income originating from shared energy.

This international review highlights similarities in common challenges such as operational and investment costs or variability of supply and demand addressed by isolated islands worldwide, which despite their peculiarities, usually require overarching solutions. Each island or region is unique, stressing the need for customised solutions such as submarine transmission extensions and ESS aligned with an ambitious deployment RES plan.

2.4 Demand modelling

In the Greek islands' context, high uncertainty and seasonality are observed. Tourism demand shapes the annual demand profiles, recording spikes over the summer months, while residential demand requires a baseload profile across the year. Similar to supply-side management, long-term demand forecasting allows for effective transmission and generation planning on the Greek islands while securing a reliable power supply, typically considering annual or multi-annual time steps. In the short term, it balances demand and supply to ensure a stable power system operation, usually simulated at high temporal resolution (days, hours, minutes). Furthermore, an intermediary stage from months to a few years is vital for planning maintenance schedules, hydrothermal coordination, and developing cost-efficient fuel purchasing strategies on islands (Amjady and Keynia, 2008). Despite the volatility recorded in the region in the literature reviewed, demand forecasting analysis has not been conducted exclusively for the Greek islands' region.

Most of the electricity dispatch optimisation and simulation models as well as power system analysis tools discussed before, usually treat demand load as an exogenous input at an aggregated level without considering the individual demand sectors such as the residential, industry and transport. Models such as COMPETES, DIMENSION, EMPS and PLEXOS presented here include demand elasticity functions subject to price and shadow price signals. At the same time, most offer demand response services, usually simulated as a negative demand load. Hence, the need for robust demand forecasting modelling, considering mainly buildings as well as industry, has been so far reflected in two fundamentally different approaches frequently encountered in the literature and employed in the analysis included in Chapter 3. These are the Bottom-up (or microeconomic modelling) and Top-Down methods (or macroeconomic modelling) or approaches combining both methods.

2.4.1 Bottom-up

Bottom-up modelling targets the end-user level information that follows the relevant analysis collated to a higher level, usually concerning a sector or country (Zweifel, Praktiknjo and Erdmann, 2017). Bottom-up models emphasize detail while allowing users to compare the impact and choose between different technologies and usage intensity. This allows identifying the direct effect of technologies, policies or behavioural patterns on increasing efficiency. The drawbacks are their complexity due to the reliance on micro-data requirements and their interlinkages. Besides, bottom-up models do not consider the connections between the energy system and the macro-economic sectors, thus neglecting their impacts (Prina *et al.*, 2020).

Review papers have been published categorising bottom-up energy demand forecasting models, methodologies, and case studies at different levels. A review of bottom-up building stock models for energy consumption in the residential sector is presented by Kavgic et al. (2010), highlighting that the lack of publicly available data and the complex algorithms employed embed high error risks. (Prina *et al.*, 2021) discussed bottom-up energy system models applied to insular systems. A thorough review has been carried out highlighting the differences between tailor-made models for islands such as HOMER with additional, customised constraints and national-flexible models, e.g. EnergyPLAN and TIMES, applied to islands' case studies. The review does not emphasise demand models but showcases those with demand response features. Also, Prina et al. (2020) split the modelling approaches into static (short-term) and long-term. Static models employ a short temporal horizon and emphasise the target year. Long-term models include a longer projection horizon and time-step, overseeing the energy system's development until the target year. A division within the long-term category is the perfect-foresight approach or myopic approach. One more categorisation of bottom-up models is the statistical and the engineering or building physics-based techniques (Swan and Ugursal, 2009). The first category shapes certain end-use contributions in the final energy demand, subject to human behavioural control while relying on data obtained from surveys, databases, and public documentation. Whereas engineering techniques explicitly calculate end-use energy consumption based on detailed descriptions of a representative set of houses and later extrapolate it to wider regions or clusters of households with similar characteristics (Suganthi and Samuel, 2012).

One of the first tailor-made bottom-up approaches for building residential profiles was presented by Capasso *et al.* (1994). A load-shape synthesis approach was applied considering the individual appliance demand per household to produce the end-use area load profile eventually. Furthermore, the authors introduced their model, 'behavioural' and 'engineering' probability functions to reproduce the psychological factors affecting residential demand using a Monte-Carlo extraction process. Following on, a series of demand models at the residential level have been published over the last two decades. Gyamfi and Krumdieck (2012) describe a bottom-up diversified demand model used to estimate residential customers' load profiles. This paper estimates demand response effectiveness without measured data while showing the impact of individual household appliances on reducing the utility network's peak load.

Similarly, Chrysopoulos *et al.* (2014) introduce a small-scale consumer model that delivers parameterised statistics of electrical consumption profiles considering real-life consumption measurements. The authors demonstrate that the model's accuracy improves significantly as the available data increases. McNeil et al. (2013) developed a novel approach that calculates potential energy and GHG impacts of efficiency policies for lighting, heating, ventilation, air conditioning, appliances, and industrial equipment. It demonstrates that a cost-based scenario is highly desirable to establish the economic potential of energy policies that replace the existing appliances stock.

Sakah *et al.* (2019) applied multiple linear regression analysis using residential electricity consumption survey data of 60 households. The dependent variables are appliance ownership and electricity consumption, while the independent variables include socioeconomic and building characteristics. Results suggest that lighting, air conditioning, refrigeration, television, and fan contribute to 85% of residential peak load, while only the AC systems' management could reduce residential peak load by 11%.

Streicher *et al.* (2019) published an analysis for Switzerland via a bottom-up model regarding space heating demand, proving the reliability of building data from energy certificates. Some key results highlighted the effect of rural typology, building type, and age in determining the space heating demand. According to the authors, the model's scalability could be applicable to other regions of various sizes, such as islands. A bottom-up prediction model is produced by Aki, Wakui and Yokoyama (2016). The algorithm computes the required hot water quantities and end-uses timing considering historical data and displays them as forecast data. In order to increase the accuracy of such methods, Hakimi (2016) employed stochastic domestic load modelling while using the collected data from a residential complex, succeeding to estimate precisely the behaviour of controllable loads in particularly washing machines as an example.

Gouveia, Fortes and Seixas (2012) used the TIMES model to assess technology options and final energy needs for end-uses considering a sensitivity analysis for residential buildings in Portugal. The study indicates that technology may cumbersome behavioural habits or lifestyle changes for space heating and lighting uses. Concerning other uses related to thermal comfort, they could prove particularly uncertain regarding energy consumer behavioural practices. This conclusion confirms the lack of sufficient data on how energy consumers behave in their homes, how they use technologies and how they react to energy efficiency policies. Li, Keppo and Strachan (2018) use the TIMES model to include heterogeneous households' preferences in the modelling process. While exploring various factors, the available technologies and the number of bedrooms are the key parameters when modelling the penetration of heating technologies in the UK energy system. This analysis underlines the importance of including a temporal household preference element when cost impact is limited. In a similar context, Niamir *et al.* (2020) empirically investigate the bottom-up drivers and barriers behind households' energy use choices as a dynamic process unfolding in stages. They show that behavioural factors, next to structural and monetary factors such as income and education, play an essential role in energy decisions. Sardianou (2007) concluded through an empirical analysis that higher-income Greek households, along with self-owned properties or residents belonging to a broader family core, are more likely to increase energy savings. On the other hand, the number of rooms or the dwelling size do not have such an immediate effect.

While most studies target the residential sector, there has been relevant research to forecast electricity demand and the impact of various policy measures on non-residential sectors. Mahendra *et al.* (2019) used the bottom-up LEAP model to forecast electricity demand in Bangka island in Indonesia across all sectors, e.g. residential, commercial, public, industry etc., showcasing one of the few studies targeting demand on islands. The authors showed that demand would grow by 1.83% per year while the dominant sector is residential. The study also investigates the generation and transmission expansion plan to fulfil the demand increase. Jakob *et al.* (2012) use FORECAST model to project the tertiary electricity demand for several scenarios up to 2035 with an outlook to 2050. The scenario analysis shows that if the current diffusion speed concerning energy-efficiency measures trends continues via a BAU scenario, electricity demand in the tertiary sector will likely increase further with a saturating tendency. On the other hand, the analysis shows a noteworthy dynamic for energy efficiency beyond today's BAU.

2.4.2 Top-down

While bottom-up models could link the various energy uses to macro-economic parameters (Kavgic et al., 2010), top-down models link the demand forecasting of the energy sector with these historical variables, usually aggregated to the national or regional level. In contrast, they are used for supply analysis based on long-term energy demand projections by accounting for historic responses (Swan and Ugursal, 2009). Their application field evaluates the impacts of energy and climate policies on socio-economic sectors such as social growth, public welfare and employment while they could be categorised as econometric and technological top-down models (Prina et al., 2020). Some literature methods concerning top-down approaches include regression and exponential analysis, neural networks, fuzzy logic, and agent-based and input-output models (Suganthi and Samuel, 2012; Prina et al., 2020). One fundamental diversification of top-down models concerns the econometric and technological models. Econometric models are based primarily on price (for energy and appliances) and income. At the same time, they use real data and apply methods such as time series analysis to study end-user behaviour. Technological models ascribe the energy consumption to the entire housing stock's broad characteristics, such as appliance ownership trends. Besides, some models use both methodologies (Swan and Ugursal, 2009). Even though economists and public administrations typically adopt top-down techniques, they employ a simplified representation of the energy system's elements and intricacy. Consequently, they are not always suitable for investigating or defining sector-specific policies. These methods depend on historical data, which usually fail to capture future technological developments and geopolitical or economic incidents impacting demand.

Kostakis (2020) presents region-fixed effects using Ordinary Least Squares (OLS) and Quantile Regression methods concerning Greek households considering data from the nationwide 2017 Household Budget Survey covering 6,176 households. The study reveals that household energy consumption is correlated to disposable income, educational level, age, and employed household members. The results show that households with higher social status usually require more intense electricity use. Also, male households appear to be more conservative in electricity use because they use appliances more effectively or possess fewer. Finally, the results show regional heterogeneity related to weather conditions, household energy habits, and household size related to electricity consumption. Structural stability, price and income sensitivity of both long and short-run residential demand for electricity in Greece were examined by Hondroyiannis (2004) while using a linear double-logarithmic form including income, price and weighted average temperature as independent variables. The results indicated a strong correlation between the variables and the electricity demand.

An econometric analysis using household survey data by Pachauri (2004) concerning Indian families reveals that household expenditure per capita positively impacts the total energy requirements. An empirical relationship between household decision variables and characteristics unveils country-specific impact. Furthermore, variables associated with household dwelling characteristics, family composition and demographics seem also to have a considerable effect. The influence of family and household characteristics is also investigated by Mills and Schleich (2012). The study disclosed that households with younger ages have a stronger tendency to place primary importance on energy savings for environmental reasons. On the contrary, households with a high share of older residents emphasize financial savings and present lower technology adoption rates.

Fumo and Rafe Biswas (2015) performed simple multiple linear and quadratic regression analyses on hourly and daily residential data. The study proved that as the data time interval increases, the accuracy of the models improves. For the residential sector, the model shows that HVAC systems cover a large share of the buildings' total energy consumption, while their performance can be modelled as a second-order polynomial equation. Therefore, a quadratic regression model can provide more accurate results for shorter time intervals such as an hour. Regression analysis is also applied by Hasib, Islam and Islam (2013) concerning Kutubdia island in Bangladesh. Here, the off-grid area is indicated as a dependent variable, while the on-grid area is taken as an independent variable. The monthly regression analysis results were compared with the Inverse Matrix Calculation technique applied in MATLAB software, validating each other.

An original study by Tyralis *et al.* (2017) introduced an interdisciplinary approach emphasizing short and long-term planning due to the uncertainty in projecting socio-economic variables and modelling the interactions between them and the electricity demand. The results show that the oil price may change the annual electricity demand distribution non-linearly. Furthermore, variables such as the gross domestic product (GDP) and heating oil prices affect the distribution and the quantity of electricity demand on extended time scales.

2.4.3 Hybrid

Top-down macro-economic and bottom-up models have been combined, forming ‘hybrid models’ which could benefit from the advantages of coupling micro with macroeconomic approaches. This is usually achieved either by soft-linking the models and manually transferring data and parameters from one model to the other or by automatically connecting the two methods (hard-linking) (Prina *et al.*, 2020).

An econometric study of the Portuguese residential electricity consumption has been published by Wiesmann *et al.* (2011), suggesting that the electricity demand in Portugal will be notably affected by socioeconomic and technological advancements in the building stock. The authors investigate the association between the dwelling and household characteristics on per capita residential power consumption considering two levels linked to two databases. The first level utilises data aggregated by the municipality for 2001 (top-down). The second level includes micro-scale data from the Portuguese consumer budget survey from 2005 and 2006 (bottom-up). This study shows that household and dwelling attributes considerably affect residential electricity consumption while the income per capita is low in the final household electricity consumption. Adeoye and Spataru (2019) proposed a hybrid demand model for West African countries. The hourly electricity demand is modelled using a bottom-up approach for the urban and rural households in the residential sector. In contrast, in the non-residential sector's demand, the end-uses have been aggregated and modelled through multiple regression analyses considering extensive socio-economic, technical, and weather parameters. The authors point out that the 2030 annual electricity demand is expected to be fivefold higher than in 2016 in the West African region, with the non-residential sectors anticipated to experience the foremost increase.

Rehfeldt, Fleiter, and Toro (2018) use the adapted FORECAST-Industry model to estimate the energy balances for heating and cooling demand for the industry sector in Europe. The methods combined bottom-up data at the process level with top-down energy balances to eventually disaggregate Eurostat's energy balance for the industrial sector. End-uses in the industrial process include a meticulous for estimating the temperature levels of process heat demand. Di Leo *et al.* (2020) presented a top-down methodology used as input in bottom-up TIMES models. A regression analysis has forecasted energy demand trends. The suggested approach defines the links between population and GDP and the energy demand in the residential, transport and commercial sectors. Overall, the study highlights a solid relation between residential and transport energy demand as well as population and GDP, while it is limited only to the latter in the commercial sector.

The literature review on demand modelling showcases various approaches subject to the data availability and the analysis requirements. Notably, for bottom-up models, it is necessary to access a wide range of data, mainly from households regarding the residential sector, coupled with the weather, socio-economic and behavioural characteristics affecting the demand forecasting. On the other hand, top-down approaches rely on historical variables, usually applied through regression analysis, significantly impacted by uncertainties regarding policies and socioeconomic indicators such as fuel prices. Such uncertainties could be mitigated by increasing the data time interval. Hybrid approaches combine various methodology segments or treat sectors with different qualitative and quantitative data features. Building on the existing literature, a relevant approach is described in Chapter 3, considering the Greek islands case study.

2.5 Electric vehicles modelling

Electric vehicles (EVs) operation on islands power systems could present multiple benefits while paving the way for decarbonization. The requirement for small driving ranges and their limited size allows for faster-regulated charging infrastructure deployment. On the other hand, the current fossil fuel-based electricity mix in parallel with the fragile local power grid requires heavy investments in generation and transmission capacity. Case studies have been reviewed in this section by introducing EV fleets in new markets while testing charging scenarios. As several examples of island paradigms are described, similarities and interesting findings in charging scenarios can be drawn from other examples at the country or city level.

The benefits of using an electric car in a system with a low carbon electricity mix were highlighted by Tomšić et al. (2020). The advantages extend to economic and performance effectiveness and user-related incentives. On that note, leading markets could increase global incentives for the uptake of EV technology with the potential to reduce emissions in systems with low carbon electricity generation, according to Helveston et al. (2015). Overall, the literature suggests that financial incentives and charging infrastructure could significantly increase EV deployment. Other benefits, such as toll exemptions and the right to use bus-designated lanes, do not seem to impact EVs adoption directly (Mersky *et al.,* 2016). Interesting findings by Sierzchula *et al.* (2014) and Langbroek, Franklin and Susilo (2016) suggest that broader variables such as income, education level, and environmentalism are not sufficient predictors of EVs adoption levels. These factors could potentially act as barriers given the socio-demographic profiles of the local population on islands, despite the progressive solid impact of tourism.

Individuals who opt-in for EVs either see electromobility as superior compared to ICE or experience behavioural change. However, their receptiveness to subsidies diminishes in more advanced stages of change, according to Langbroek, Franklin and Susilo (2016). The authors suggested raising awareness about electromobility could decrease the need for additional economic incentives. In this respect, people who believe EVs to be successful in reducing the negative attributes of the current transport system and whose travel patterns can align with the use of electromobility also have a higher probability of choosing an EV (Mersky *et al.*, 2016). Simultaneously, consumers question the uncertainty of the EV battery's environmental impact and the fuel source's sustainability (Egbue and Long, 2012).

Technical challenges and economic opportunities for EVs' system integration triggered the research community's interest decades ago. Kempton and Letendre (1997) proved that if electric grids can accommodate EV charging, there will be a need to purchase less base-load generation while matching smoother the intraday electricity system requirements. A more recent study focused on Ireland's single electricity market by Foley *et al.* (2013) using the PLEXOS model suggests that if more than 213 thousand EVs are introduced by 2020, adopting off-peak charging patterns, they will contribute 1.5% to the target of reaching 10% RES share in transport while reducing emissions reduction by 210 ktCO_2. Wang et al. (2011) considered Plug-in Hybrid Electric Vehicle (PHEV) this time and proved that optimal dispatch of the vehicles' charging load using smart techniques could considerably reduce the operating costs while favouring demand response implementation. In the Greek electricity system, a steady-state analysis applied by Voumvoulakis *et al.* (2017) revealed the maximum number of EVs that can be integrated considering the profiles of EV drivers, type of vehicle, travelling distance, road conditions etc. The differences between EVs integration in rural and urban distributed networks in Greece showed criticalities in the latter. However, if the appropriate charging strategies are applied, they could minimise the problems and enable more electric vehicles to be deployed.

Various approaches in the literature address the impact of different charging scenarios. A number of studies assess scenarios only with one simple charging pattern (Hodge, 2010; Nunes, Farias and Brito, 2015). Hodge (2010) indicates that adopting V2G approaches will have a limited impact on the increase of wind energy sources in California's power system as the area has already reached its maximum penetration; however, it will contribute to decommissioning conventional stations kept in reserve. Nunes, Farias and Brito (2015) proved that if solar PVs provide a significant fraction of Portugal's electricity system by 2050, EVs could offer an opportunity to use that excess electricity by charging during morning hours, a case that could have high applicability in the Greek islands. However, such a case will require most EVs to charge during the day, changing the culture and probably conflicting with the drivers' daily routines. Foley *et al.* (2013) proposed two main charging patterns. The peak charging assumes drivers will charge their cars directly after arriving home, while the off-peak charging assumes drivers will charge their EVs later to take advantage of cheaper electricity or use smart metering to control the charge of EVs and fill in the night valley.

Other studies enhance their simulations while assessing innovative charging strategies, aiming to coordinate RES penetration directly. Van der Kam and van Sark (2015) developed a model through EV charging algorithms tested in a microgrid to increase solar energy's self-consumption through smart charging while employing cutting-edge grid technology. The simulation results demonstrate that EVs can support demand and supply balancing while self-consumption increases. Similarly, Ghofrani, Arabali and Ghayekhloo (2014) used techniques such as the autoregressive moving average (ARMA) time series model for PV generation forecasting, coupled with Fuzzy C-means (FCM) for clustering EVs into fleets with similar daily driving characteristics. Smart scheduling, as proposed, demonstrates the efficiency of the developed algorithm to enhance the utilization and predictability of PV power concerning EV charging while reducing the penalty cost significantly.

The most common and resourceful modelling approach is to employ a wide range of charging scenarios, with combinations and alternations of opportunistic, delayed, night-time, smart, and V2G charging options. Mullan *et al.* (2011) investigated the impact of electromobility, assuming a 10% share of EVs in the total fleet of Western Australia, a geographically isolated area that resembles a geographical island. The study proposes three scenarios: evening charging, night-time charging, and a smart scenario that charges cars based on demand management. The study showed multiple benefits if off-peak charging is applied in the short term. At the same time, it increases the utilisation of the existing transmission capacity combined with higher efficiency in the base-load generation. Also, long-term benefits are foreseen related to prohibiting unnecessary investments. Using a mixed logit model Sun, Yamamoto and Morikawa (2015) predicted how certain factors impact EV user choices concerning the regular charging of an EV after the last trip of the day. Four scenarios were considered: charging directly upon arrival at home or work (if applicable), charging during the night, and random charging. The authors showed that the likelihood of regular charging after the last trip of a working day increases for commercial users while decreasing for private users, allowing coordination among the charging loads. The study also mentioned that users' family and personal characteristics, such as income and age, impact their charging routines. Li *et al.* (2017) used the Monte Carlo simulation to analyse EV charging patterns, their economic impact, and the social cost under four different scenarios: the disordered, the valley charging, the smart charging and the V2G scenario. The results prove that the smart option is the most efficient scenario, which reduces the user cost, and in parallel, it moderates load changes and V2G. The bidirectional charging achieves optimal economic and social costs in the long run.

The peculiarities of deploying electric vehicles in isolated power systems are assessed by simulating different EV penetration levels in Kadurek, Loakimidis and Ferräo (2009). The authors show that if charging and discharging rates exceed a certain moderate level, they could impact daily demand patterns while putting the security of supply at risk. As such, smart charging hand in hand with RES growth could contribute to ensuring the required storage and backup power in such systems. Similarly, according to Pina *et al.* (2014), the high share of RES in Flores island in the Azores did not trigger considerable additional use for charging, as, during peak hours, the extra generation was produced by local oil-fired generators. However, by adopting a flexible charging behaviour, the share of renewables contributing to the system is doubled. Emissions reduction by 47% is showcased in Da Silva, Lopes and Matos (2011) once EVs are introduced on São Miguel's island when combined with high RES share and energy efficiency measures. The V2G option is not judged as economically profitable for the island electrical system. The benefits of EVs improving the system's reliability in Azores islands is also explored by Silva and Ferrão (2009) through a broad range of scenarios combining renewables with EVs and energy efficiency measures. A case study for Tenerife Island shows that fast charging and discharging, backed by smart control systems, could flatten the demand curve. As in most papers, it addresses a smooth, gradual EV integration into the system to allow for parallel RES penetration (Colmenar-Santos *et al.*, 2017).

The benefits of renewables development supported by EVs for Galapagos islands is investigated in Clairand *et al.* (2019). The authors highlight that despite significant regulatory and economic constraints related to up-front investments, EVs could improve the local energy system from an economic point of view while reducing emissions by approximately 16% and operational costs by 1%. Vehicles providing power to the grid in isolated power systems were also covered by Joa, Soares and Almeida (2011), demonstrating that EVs could contribute to voltage control when connected to the system in case of sudden changes in dispatched load.

Raveendran, Alvarez-bel and Nair (2020), in a case study concerning the Balearic Island of Menorca, assess the participation of different types of EVs in providing flattening ancillary services to support solar PV integration. The paper highlights the vast potential of V2G in offering such services. Furthermore, coordinated charging under an aggregator boosts the potential of EVs in providing power regulation band and storage services during peak sunshine hours. Grid services are also investigated by Pillai and Bak-jensen (2011) for bidirectional V2G charging. The study shows that thermal generators' power regulation requirements significantly decrease while adopting a V2G system participating in load frequency control. Such a system could support the electricity network operation by reducing transmission congestion and grid reinforcement costs. Similar constraints of adopting V2G systems on islands are encountered in large interconnected markets such as central Europe.

Taljegard *et al.* (2019) justified that V2G benefits are not evident in RES system integration when the EV fleet share that participates exceeds 24%.

Overall, the literature indicates that EVs can significantly reduce the amount of excess renewable energy produced on electricity systems such as islands while reducing operating costs and supporting the grid. In this respect, charging scheduling and V2G, when backed up by smart infrastructure and a high-RES system penetration, prove to have the highest efficiency in balancing demand and supply. Such strategies correlate demand valleys with EV charging and peaks with discharging while contributing to emissions reduction, one of the main goals for the Greek islands' electricity system under transition.

2.6 Thesis contribution to the literature

The literature points to the following main gaps:

I. Despite their suitability, highly flexible optimization models, particularly 'Integrated models' as reviewed in Section 2.2 have rarely been used to simulate interconnections among islands or between the islands and the mainland. This highlights a lack of variety in modelling methods on island systems concerning transmission extensions, energy storage applications and dispatch scheduling.

II. The studies exploring future energy scenarios for the Greek islands usually focus on one (single) island or a region. They are not inclusive enough to assess the techno-economic and environmental impact of future interconnections or autonomous operations at the national level. This constitutes one of the key shortcomings, resulting in an incapacity to provide policy, regulation, and market recommendations.

III. The literature on the techno-economic viability of future interconnections and BESS on the Greek islands is limited. In this regard, there is a lack of up-to-date data and approaches linked with the fast-paced technology evolution.

IV. Limited research has been conducted concerning hybrid modelling, including submarine interconnections and energy storage technologies.

V. Furthermore, most studies lack detail in representing the transmission grid, while they usually fail to incorporate social planning and broader techno-economic restrictions into their modelling exercise.

VI. Most case studies emphasise solar, wind, and PHS technologies, while limited analyses incorporate other RES technologies as part of the optimization process.

VII. Although extensive research has been conducted in the international academic community regarding demand modelling and forecasting, the Greek islands have not been covered so far. This is due to the lack of available data for such a small region in conjunction with relatively low interest in applying efficiency measures despite the high potential due to the old building stock.

VIII. Even though the Greek government has prioritised the deployment of EVs in parallel with charging infrastructure on the Greek islands, their electricity system operation has not been stressed under a scenario with increased fragmented demand due to EV charging loads.

Therefore, the scope of this thesis addresses modelling for the Greek islands' region in a more holistic way than previous studies through a novel methodological approach with inclusive scenarios assessing the impact on the whole Greek electricity system. The expected novel contributions lie in:

I. The optimisation of the Greek electricity system, including the NGS and the NIIs, explores competitiveness between renewable energy deployment in the interconnected and the currently non-interconnected region. While assessing multiple scenarios through sensitivity analysis, the impact on the security of supply, the effect on the electricity prices, generation costs and CO_2eq emissions are evaluated.

II. An integrated methodological approach combines short-term dynamics with long-term (and medium-term) planning.

III. A wide variety of available RES technologies were included, considering hourly forecasting coupled with solar thermal, PHS and BESS at utility-scale coupled with interconnections for the first time. All existing and upcoming interconnections have been treated in detail for the first time.

IV. Updated input data concerning the national climate targets which drive RES deployment have been included and aligned with the National Energy and Climate Plan (NECP) and other relevant reports.

V. As an additional novel element, this PhD processes data from two household surveys (Hellenic Statistical Authority, 2012a, 2016b) and energy performance certificates (Hellenic Republic - Ministry of the Environment and Energy, 2016a, 2017b, 2018a). Weather and historical and socio-economic data through a hybrid (bottom-up and top-down) approach define end-use consumption, emphasising the residential and services sectors. 20-year demand forecasting was treated in ISLA_EGI top-down simulation model, which produces long-term demand scenarios at different time scales.

VI. This PhD develops a novel modelling approach in PLEXOS, to test the entire electricity system's operation under increased fragmented demand through charging scenarios. Gaps in the Greek Government's strategy on EVs deployment on the Greek islands are addressed. The impact on RES generation and the economic and environmental implications are also evaluated.

Following an implicit comparative analysis, PLEXOS was selected among other integrated electricity system models as it precisely answers the research question and objectives indicated in Section 1.4. Specifically, it allows for short-term dispatch modelling and long-term generation and transmission capacity expansion. PLEXOS builds up hourly demand forecasts when annual projections are incorporated. It also covers emissions, ESS technologies and performs EVs modelling. PLEXOS applies economic optimisation without overlooking policies and other social, environmental or techno-economic restrictions introduced in the model through equations, shadow prices and constraints. The model offers a wide range of data-driven flexibilities creating a dynamic solving modelling framework while introducing unlimited input parameters and scenarios.

This study uses PLEXOS to simulate and optimise the Greek islands' electricity system and the NGS under a holistic approach. Novelties in how PLEXOS was treated beyond the geographical scope and the granularity of system data lie in incorporating new constraint equations. Also, BESS sizing and the methods applied to simulate EVs while bringing together existing and new functions have high replicability in other contexts. PLEXOS is soft-linked with the ISLA_EGI demand model while including demand projections produced in the latter. The original ISLA model was developed by Spataru (2013). It is flexible enough to host inputs and assumptions per island system and demand sector and apply long-term forecasting. ISLA incorporates such inputs as a product of extensive exogenous data modelling described in the next chapter.

3. Modelling the Greek islands annual electricity demand

3.1 Summary

The methodology of estimating the future annual demand profiles is presented in this chapter by the means of two scenarios for 19 islands' electrical systems addressing the Research Objective I:

To assess the impact of future demand scenarios incorporating energy efficiency policies on the electricity generation mix.

For long-term forecasting ISLA model has been adapted to the Electricity Sector of the Greek Islands (ISLA_EGI). This model is utilised to anticipate future annual demand profiles incorporating assumptions and inputs related to electricity consumption in public, residential, services, industry, and agriculture sectors.

An extensive bottom-up approach and demand-driven analysis are applied to estimate the residential demand profiles per end-use in 2016, incorporating data from two household surveys in 2012 and 2016. Through the means of regression analysis, while utilising the indicators of economic growth and regional demographics in a top-down manner, the regional demand growth is configured. Moreover, it has been anticipated that the two Socioeconomic Driven Scenarios vary based on distinct presumptions regarding the growth of population, GDP and household size. Similarly, two Energy Efficiency Scenarios have been considered in the model, reflecting different technological progress assumptions and the consumers' behavioural patterns.

The services sector incorporating the commercial and tourism sub-sectors has been projected via one socio-economic scenario linked to tourism demand. The demand analysis is performed, including statistics related to electricity consumption issued from Energy Performance Certificates (EPC) and the building stock on each island. Two energy efficiency scenarios have been applied considering two different trajectories: the Ambitious and the Average. Other sectors are treated with simplicity without diversifying their trajectories, considering one scenario for each sector at an aggregated end-use level.

Overall, two Principal Scenarios, the Low-Efficiency (Low_Eff) and High-Efficiency (High_Eff) were configured, combining assumptions across all sectors. The results demonstrate that the key sector driving demand on the Greek islands is the services sector affected by the optimistic projections for tourism growth over the following decades. The long-term generated data per electrical system, e.g. transmission region (R) from 2020 to 2040, have been incorporated in the Greek ıslands' electricity system model developed in PLEXOS and described in Chapter 4.

The methodology is validated by comparing the research results with the actual data of Crete island per end-use in 2016. Moreover, the outcomes of the ISLA_EGI model concerning Crete are contrasted with that from the PRIMES modelling framework. Conclusively, the actual aggregated demand data of the entire islands' region is contrasted against the results obtained through the modelling.

3.2 Description and methodological approach

Annual demand projections for the Greek islands were produced using the ISLA top-down simulation model developed by Spataru (2013). The model was developed to analyse the future energy supply by incorporating long-term demand scenarios based on historical trends, policies, technology costs and performance at different time scales. It includes all energy source streams, demand sectors, energy technologies and their characteristics, as well as demographic indicators. ISLA is built on Visual Basic Application (VBA) in Microsoft Excel and Python. It has been applied to analyse more than 300 case studies projected in the territories of islands worldwide[16].

Considering the purpose of achieving the research objectives and the scope of this analysis, the ISLA model was adapted to the Greek ıslands' power system to calculate electricity demand profiles. This study will refer to ISLA_EGI, where

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[16] www.islandslaboratory.com

EGI stands for Electricity Greek Islands. The objective is to calculate the final utilisation of the electricity, which accounts for the secondary energy products and services delivered by energy markets to final and intermediate consumers over a single year within a given projection horizon and comprises all transformed products into electricity, such as coal, natural gas, oil and renewable energy. Transport is treated outside the ISLA_EGI model as described in Section 4.7. Electricity demand scenarios in ISLA_EGI are used only to analyse the demand side, while the supply side is modelled via the PLEXOS energy system model as described in Chapter 4. The two models are soft-linked by integrating the ISLA_EGI demand scenario results to PLEXOS, which treats demand exogenously (Figure 3.1).

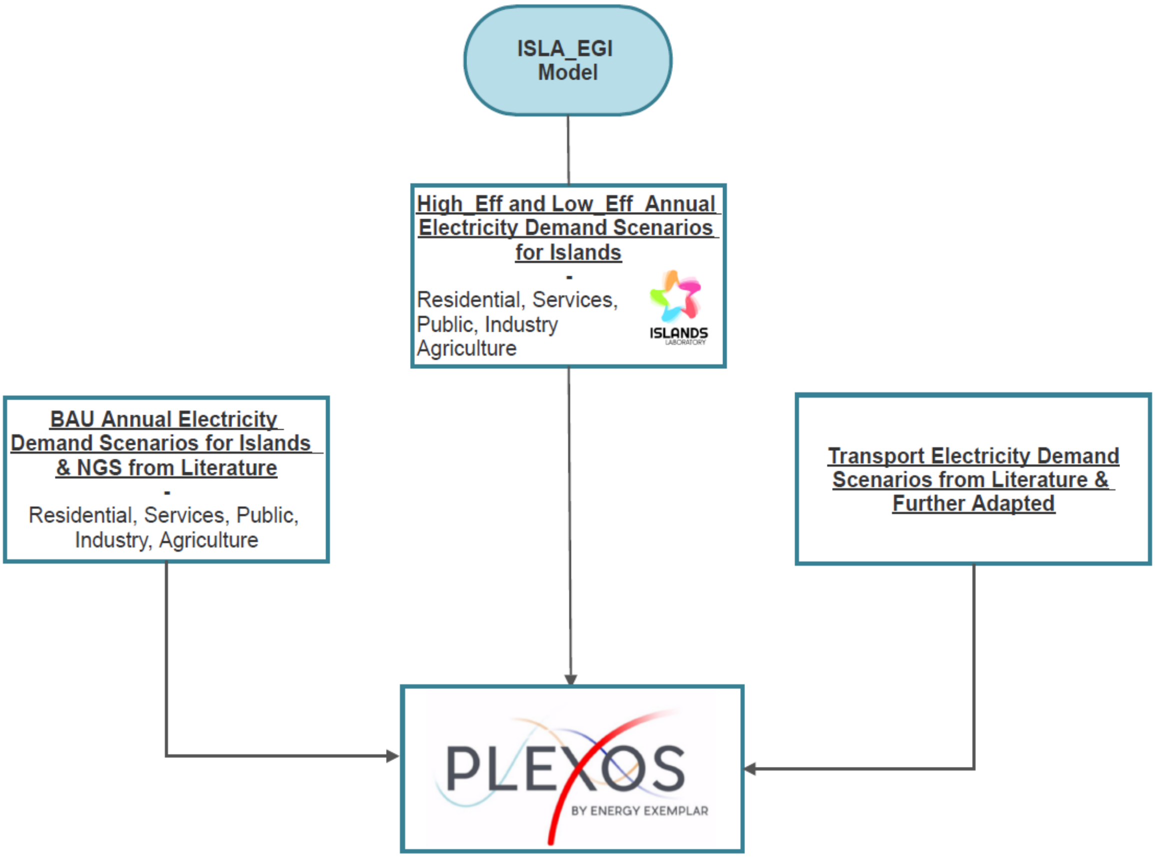

Figure 3.1: ISLA_EGI soft-linking with PLEXOS energy system model

The temporal resolution for energy demand projections was set to one year, which is the minimum time step to align with the simulation time steps envisioned in this study. The planning horizon was regulated to 2020-2040, with 2016 as the base year. 2016 was selected since it offered the latest available data across the demand and supply sides. The Geographical resolution covers the 19 AES here called transmission Regions (R).

Electricity takes a considerable share, accounting for 34%, 39%, and 47% of the final energy in Crete, South Aegean, and North Aegean, respectively. The electricity demand on the Greek islands incorporated in the modelling exercise is split into six categories: Residential, Commercial (services), Tourism (services), Public, Industry, and Agriculture, as illustrated in Figure 3.2. The Services sector is the leading power consumer in the non-interconnected region exceeding 44% of the total electricity generation, while historical data represent a tendency of growth over the years due to the increased demand for tourism. Tourism plays a different role across each islands' region, with Northern Aegean Sea islands being less affectionate to tourism. In contrast, South Aegean is the leading region, particularly the Dodecanese area. An average share of electricity between the commercial and tourism activities is recorded. The residential category is the second most electricity-intensive sector, especially in the Northern Aegean Sea region, with low tourism levels. The remaining sectors play a small role in the regional power consumption, usually comprising less than 10% of the total electrical demand.

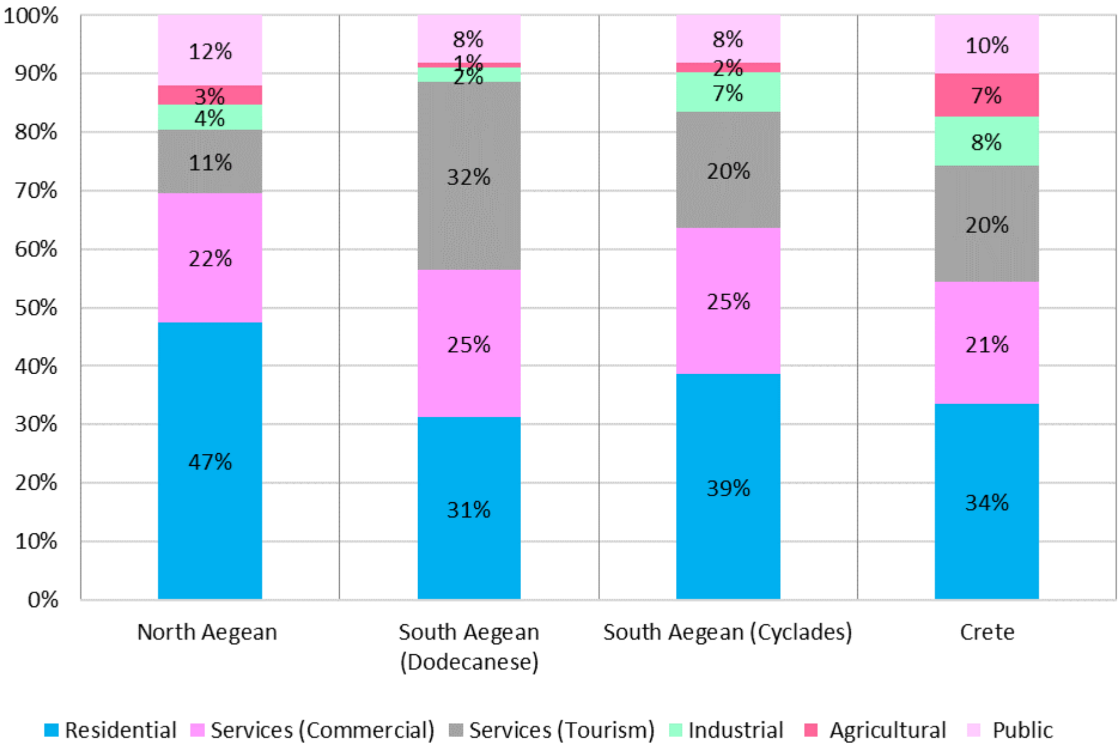

Figure 3.2: Electricity demand shares per sector and IR (2016)

The electrical uses considering the residential and services sectors are broken down to end-uses in the model, as illustrated in Figure 3.3. Due to insufficient data and the small impact of other sectors, i.e., public, agricultural and industry, were treated simplistically in the model without further fragmentation to end-uses. ISLA_EGI model executes the inputs from the final electricity consumption[17] or the useful electricity demand[18] for the reference year (2016) and calculates one of the two variables for the whole projection horizon as presented in Eq. 3.1 to Eq. 3.4.

Statistics on demographics incorporated in the model have been used to calculate the domestic demand growth factors outside ISLA_EGI. Furthermore, the

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[17] Final electricity is the electricity the island consumer buys or receives

[18] Useful electricity is the input in an end-use application

scenario configuration is exogenous and can accommodate the modelling requirements. In this respect, scenarios in the model target the electricity demand growth at the end-user's level, the efficiency and uses of appliances, renovation rates, and technology-specific trends as explained in Sections 3.3.5 and 3.4.3.

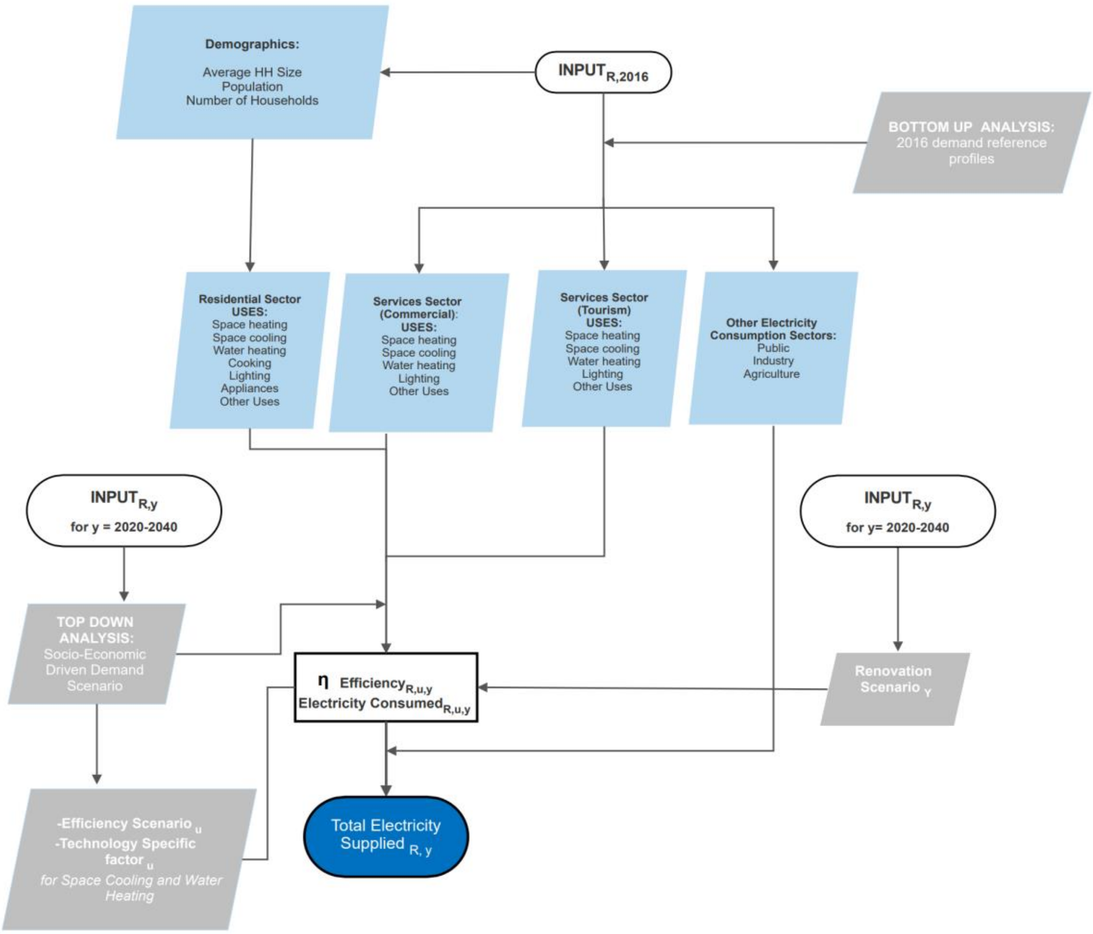


Figure 3.3: Flow chart of data processing and ISLA_EGI model adapted for the Greek islands

$$Total\ Electricity\ Supplied_{R,y} = \sum_{Y} \left(\sum_{u} \frac{DY_{u,R,y}}{\eta_{u,R,y}} + SO_{R,y}\right)$$

Eq. 3.1

Where the electricity demand per sector (DY) is calculated as:

$$DY_{u,R,y} = DY_{u,R,y-1} * \left(dg_{Y,u,y} + dtr_{Y,u,y} - AS_{Y,y}\right) * t + DY_{R,y-1}$$

Eq. 3.2

Where:

'Y' is the type of energy consumption sectors (R for Residential, C for Commercial, and T for Tourism etc.);

'u' is the end-use under each sector;

'R' transmission region which stands for each AES (or the NGS);

'y' is the year;

't' is the time step (here is considered one year);

'dg' is the coefficient related to the demand growth of electricity use per year and scenario considering socio-economic indicators;

'dtr' is the coefficient related to technology-specific demand trends for space cooling and water heating uses per year and scenario;

'AS' are the annual savings from renovations at the building envelope per year, sector and scenario;

'SO' is the electrical energy supplied to the rest of the sectors, i.e., public, agriculture and industry sectors, which are excluded from the bottom-up analysis;

'η' is the efficiency factor calculated as the proportion (%) between the useful electricity demand and final electricity consumption (Eq. 3.3).

$$\eta = \frac{Useful\ Electricity\ Demand}{Final\ Electricity\ Consumption}$$

Eq. 3.3

The efficiency factor per use and year is calculated according to Eq. 3.4.

$$\eta_{u,y} = \eta_{u,y-1} * es_{u,y} * t + \eta_{u,y-1}$$

Eq. 3.4

Where 'es' is the coefficient for the efficiency scenario per energy use and year.

3.3 Residential sector

3.3.1 Reference demand profiles

The residential demand profiles for 2016 are defined by data analysis utilising a bottom-up approach in the framework of the ISLA_EGI model, per region. This has been performed by analysing and categorising their habits and occupancy rates of weather-dependent uses such as heating, water heating, cooling systems but also lighting. as well as non-weather dependent uses, including mainly household (hh) appliances and cooking. The data used were extracted from the two most updated surveys during the analysis, conducted by the Hellenic Statistical Authority (2013, 2016a, 2016b) (Table 3.1). Given the 2016 profiles as a starting point, future residential electricity demand predictions rely on a top-down approach, as explained in 3.3.5.1. The overall analysis can be characterised as a hybrid.

The first and more inclusive source of data is the ‘Survey on the Energy Consumption in Households’ (SECH) which took place in 2012 in the context of the decade census, coupled with data from a more recent survey, the ‘National Survey of Household Financial Budget’ (SHFB) that took place in 2016. The 2012 survey provided the fundamental basis for applying a bottom-up analysis; hence the residential demand profiles were built for that year and extrapolated to 2016. As explained below, the data analysis was performed in MS Excel using the VBA programming language.

Table 3.1: Data Sources for building up residential demand profiles

Surveys	Year	Reference
Survey on the Energy Consumption in Households (SECH)	2012	(Hellenic Statistical Authority, 2013, 2016a)
National Survey of Household Financial Budget (SHFB)	2016	(Hellenic Statistical Authority, 2016b)

The surveys collected data at the 'Nomenclature of Territorial Units for Statistics Classification (NUTS)' 2 level defined by Eurostat[19] , called islands regions (IR). In the SECH survey, the type of final energy use and the available sources of energy used by the households is considered, including the relevant demographics of surveyed households and economic characteristics as illustrated in Figure 3.4. The analysis incorporates the assessment of the current status of energy efficiency and the level of implementation of measures and policies, including carbon-intensive resources for covering residential energy requirements. Along the same lines, the SHFB survey is populated, lacking in detail regarding data collected per end-use.

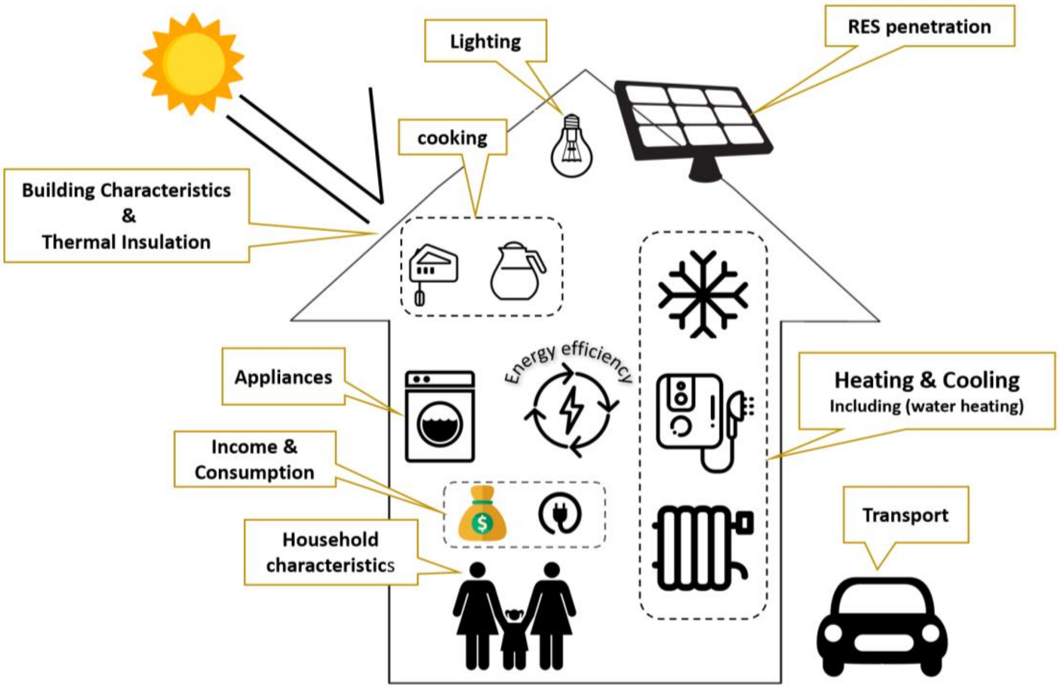


Figure 3.4: Household energy consumption data collected via the SECH survey

The sampling size of the two surveys is indicated in Table 3.2. The average sampling regional fraction is within the same order of magnitude as the national ones (0.09% for the SECH and 0.06% for the SHFB surveys). According to

[19] https://ec.europa.eu/eurostat/web/nuts/background

EUROSTAT, the minimum acceptable sampling size is 0.1% at the regional level (Eurostat, 2013). As per the estimation of the World Bank, the sample of 2,000 to 5,000 households ought to be adequate to investigate programmes affecting an amplified percentage of the population (Grosh and Glewwe, 2000). Similar household surveys display sampling sizes ranging from 0.02% (Spain) to 0.48% (Slovenia). Other studies identified in the literature record sample sizes of 13,000 (0.05%) concerning the National Housing Survey in the UK (Ministry of Housing Communities & Local Government, 2020) and between 1,000 and 4,500 households in EU, Australia, China (Greening, Greene and Difiglio, 2000; Sun *et al.*, 2014; Binks *et al.*, 2016) while the numbers are reduced to a few decades or hundreds in relevant studies in Africa (Desalu *et al.*, 2012; Gebreegziabher *et al.*, 2012). The factors that may deviate among the various surveys concern the methodological approach, limited resources, and unwillingness to participate. Given the small size of the IR and their remoteness, the two surveys' sampling sizes have been considered acceptable.

Table 3.2: Breakdown of hh interviewed per IR

IR (NUTS-2)	**Surveyed Households (2012)**	**Surveyed Households (2016)**	**Households**	**Sampling size (%)**
North Aegean	83	139	79,464	0.1-0.17%
South Aegean	48	186	116,635	0.04-0.16%
Crete	174	90	241,638	0.07%-0.04%

3.3.2 Demand profiles of weather-dependent electrical uses

3.3.2.1 *Space heating*

According to the SECH and SHFB surveys, 97% of households are artificially heated[20] (Hellenic Statistical Authority, 2013, 2016a). The remaining 3% belongs to the household income category of less than 800€/month. Approximately 60% of the survey participants live in detached or semidetached houses, while 64% declared independent heating systems. Of those dependent on central heating, 86% are equipped with autonomous heating control systems that adjust temperatures according to their requirements as well as comfort while minimizing heat waste. 56% of the households are equipped with a thermostat, while 39% is considered to set the thermostat above 21°C, which is the comfort level for the main living areas during the winter months, according to Eurostat (2013).

Most responders declare that they turn on heating for 3 to 6 months per year (Figure 3.5). To be able to validate the survey data and include trajectories for the future energy of the Greek Islands, daily data incorporating heating degree days were retrieved from the AGRI4CAST database considering a timeframe of the years 1985-2018, developed by the Joint Research Centre (JRC) of the European Commission (JRC, 2018). Furthermore, the 'Heating Degree Days (HDD)' index was applied (Eurostat, 2019a), which indicates the intensity of the cold at a particular time considering the outdoor and the average temperature of the room (precisely, their requirement of heat). The HDD calculation (Eq. 3.5) relies on the lowest daily mean air temperature, not leading to indoor heating. By using a general climatological approach, the reference temperature is set to a constant value of 15°C. This reference temperature value depends on several factors associated with the building and the surrounding environment.

$$If\ Tim \leq 15°\mathrm{C}, \qquad \mathrm{Then}\ [\mathrm{HDD} = \sum_{i} (18°\mathrm{C} - \mathrm{Tim})],\ \mathrm{Else}\ [\mathrm{HDD} = 0]$$

Eq. 3.5

Where 'Tim' is the mean air temperature of the day i.

[20] means all sources of heat from other than natural sources

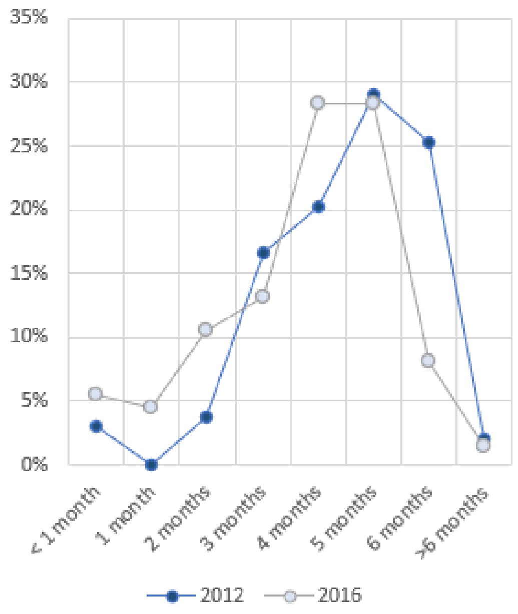


Figure 3.5: Distribution of months of use of heating systems on the NIIs

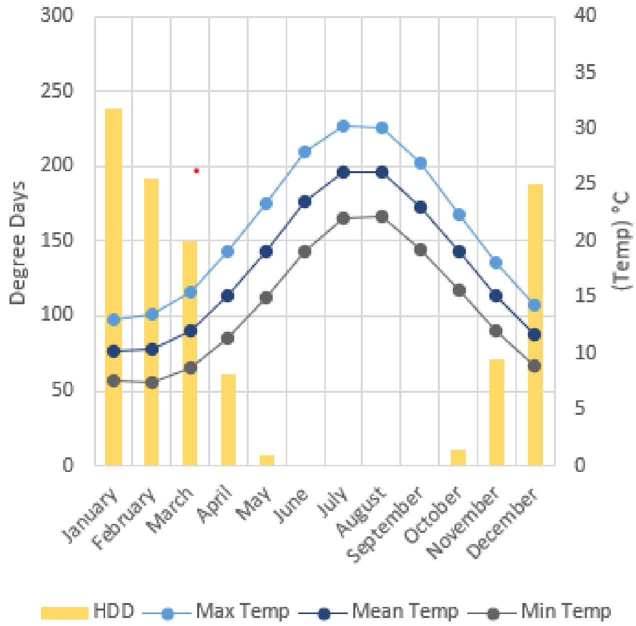


Figure 3.6: Max, mean & min temperatures and HDD on the NIIs

The monthly heating usage from the two surveys confirms the meteorological statistics that indicate the need for heating on the Greek Islands, mainly between December and March and in some cases in November and April, however, reduced to approximately 30% compared to the needs of the core winter season (Figure 3.5, Figure 3.6). The primary heating source is oil, occupying 54% of the share. As natural gas is not yet introduced on the islands due to the lack of economies of scale, electricity is the second principal source with 23%. However, the electricity on the Greek islands is mainly produced by oil with marginally lower efficiencies than new residential oil burners offsetting any potential benefits from a clean generation electricity mix. Overall, the average electricity consumption for heating purposes does not exceed 4% of the total electricity use, which designates a relatively low impact on the electricity sector. In the islands region, heating through electricity currently is supplied by ‘Heating, Ventilation, and Air Conditioning Systems (HVAC)’ and portable heaters. Until 2016, a shift towards electrification is perceived since the utilisation has increased up to 30%. Additionally, a small renewable energy fraction of 1.2% is reported.

Approximately one-third of the HVAC fleet age between 6 and 10 years, implying a replacement within the decade 2020-2030. Systems aged over 11 years (6%) will be replaced within the next five years, given an HVAC system's lifespan is between 15 and 20 years. Similarly, the age of portable heating systems identifies that 65% of the stock is between 6 and 20 years old and will need replacement between 2020 and 2030 at the latest. Furthermore, among these heating systems, 4% require replacement immediately, and approximately 27% will replace their units following 2030. Besides the product age, the replacement time is also associated with the household income and the appliances' productivity.

Between 2012 and 2016, there was a slight reduction in HVAC usage and a smoother distribution over the months (Hellenic Statistical Authority, 2013, 2016a), while the hourly heating duration is aligned among the years (Figure 3.7). Even though there is a turn towards electrification expected to become more prevalent, heating degree days are dropping over time as temperatures increase in the region by 0.8% (JRC, 2018). Assuming that the drift continues, no technology-specific factor was added for heating demand in the ISLA_EGI model. A similar heating requirement pattern is recorded for HVAC and portable heaters between 2012 and 2016 (Figure 3.8). Minor deviations could be related to specific climatic conditions or fuel/electricity prices that affect users' behaviour. Overall, most users tend to use heating systems between 3 and 5 hours per day, usually in the evening, while they rarely exceed 11 hours.

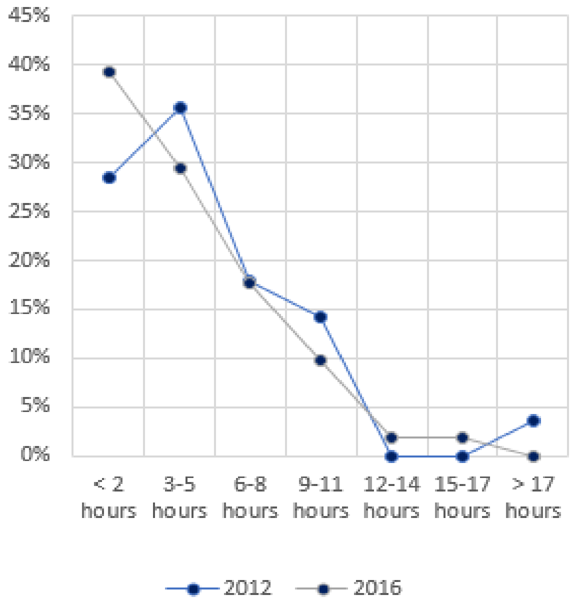


Figure 3.7: Distribution of hourly usage of HVAC on the NIIs

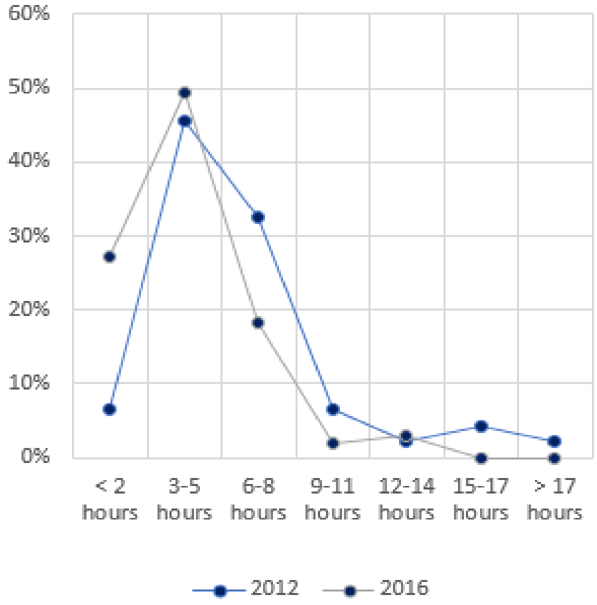


Figure 3.8: Distribution of hourly usage of portable heaters on the NIIs

The performance of HVAC systems in the heating mode incorporating the functions of heating, ventilation and air conditioning is described through the Coefficient of Performance (CoP), which is the ratio of the heating capacity to the unit's effective power input, expressed in Watt/Watt as indicated in Eq. 3.6 (PennState College of Earth and Mineral Sciences, 2015).

$$COP = \frac{P_H}{P_e}$$

Eq. 3.6

Where 'P_H' is the heating capacity (Watt) and 'P_E' is the effective power input (Watt)

The HVAC systems were split into four groups based on their class or when not available, their age. The class is defined by the EU energy labels ranging from A to G, offering a well-defined and easy indication of the energy performance of the heating and cooling devices, including all household electrical appliances and lighting bulbs (European Commission, 2020b). The inverter air conditioning units represent a distinct category as they fluctuate the compressor's speed, producing an accurate cooling or heating power output, making it up to 40% more energy-efficient (Climatevaal, 2008). The COP of HVAC systems was estimated within the range of 3.6 for inverter systems and 2.9 for unknown class and/or age older than 15 years. The omission of energy class reported could be attributed to either lack of knowledge or labelling for old devices. While associating age with energy efficiency might under or overestimate energy consumption for some devices, it is proved by Meyers *et al.* (2003), Adnot *et al.* (2004) and Mills and Schleich (2010) that it could be used as a reliable indicator for approximating energy efficiency of heating equipment or appliances, mainly because of the progressing labelling standards across the years.

In terms of the maximum units operating in a household, according to the assumption that the household has fewer heating systems than the total number of regular rooms and the heating HVAC systems are less or equal to two, we accept that the maximum units operating in parallel are two. Supposing the heating systems exceed three, but the occupants are less than three, the maximum units operating in parallel are two, and the secondary units (n≥3) are assumed to run for half of the time, as heating needs are prioritised over cooling. In case the HVAC units and the number of residents are more than three, we assume that the maximum number of units running in parallel goes up to 3 as well, while the rest of the heating systems (n ≥4) operate for the average half time. Finally, if the number of HVAC units exceeds the number of regular rooms and the number of household occupants is equal to or more than the regular rooms, the number of units running in parallel increases to the number of regular rooms.

For those months that include heating days, following the JRC methodology (Eurostat, 2019a), if the minimum temperature in a day is lower than 15°C degrees, the day is added to the heating pool days. If the HVAC is equipped with a thermostat, it is assumed that it is operational only if the min outside temperature is lower for that HDD than the set temperature in the thermostat. The coefficient '$Coef_{use}$' also represents days during which the occupants are absent mainly due to holidays or extended day-length visits. The total annual calculation of heating demand from HVACs per household is estimated according to the following equation:

$$Con\ HVAC_{h,hh}\ Total = \sum_{i}^{n} \frac{Annual\ Heating\ Use * Coef_{use} * Unit\ Capacity}{COP}$$

Eq. 3.7

Where:

'n' is the total number of HVAC systems;

*'Annual Heating Use' is the annual HDD * average daily use;*

Coef$_{use}$=0.85 or 0.93[21] *;*

'Unit Capacity' is the unit capacity of the HVAC system in KWh.

Considering that the number and the capacity of portable heaters is not described in the survey, we assumed that the number of portable heaters equals the number of regular rooms. A similar approach to the HVAC systems is applied herein.

The average electricity consumption for portable heaters is calculated as follows:

$$Con\ Ph_{hh}\ Total = \sum_{i}^{p} Annual\ Heating\ Use * Coef_{use}\ *\ Mean\ Unit\ Capacity$$

Eq. 3.8

Where:

'p' is the total number of portable heaters;

*'Annual Heating Use' is the Annual HDD * Average Daily use* Coefage;*

'Mean Unit Capacity' is assumed to be 1,500 Watt (DoE, 2019).

The total amount of electricity used for a year is the sum of the portable heaters and HVAC systems extrapolated for all the households surveyed, as illustrated in Figure 3.9. The results concern the figures from the SECH survey; as in the SHBF, there is no capacity value provided.

[21] For hh = i, if the hh head is economically active, Coef=0.85

For hh = i, if hh head is non-economically active, Coef=0.93

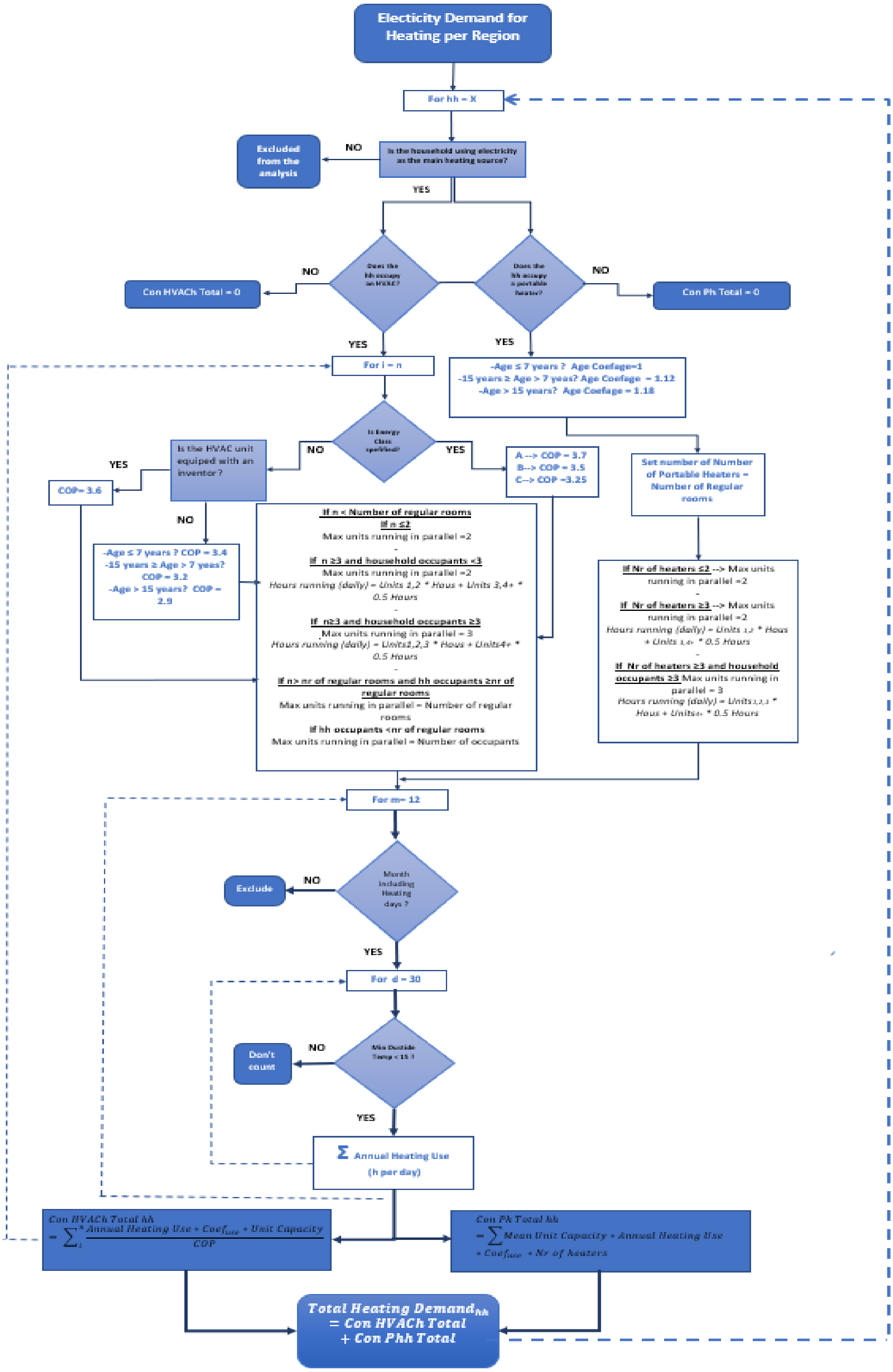


Figure 3.9: Flow chart for calculating heating electricity demand in the residential sector

3.3.2.2 *Space cooling*

Approximately 35% of the participants reported using HVAC systems for cooling and/or thermal purposes in 2012. By 2016, the percentage of utilisers was raised to 45%, demonstrating an increasing trend for cooling. 90% of the systems are equipped with thermostats, usually set to or above 21°C (considered the comfort temperature during summer) (Eurostat, 2013). The rest of the people use natural ventilation and/or air-funs at a share of 20%, responsible for less than 0.1% of the total cooling demand. The association between household income and cooling facilities is evident, while 39% of the responders possess a principal air-conditioning system with an A-class label. Nevertheless, most interviewees are unaware of the energy class of their cooling devices.

Cooling systems are used mainly between 2 and 4 months per year in the non-interconnected islands (Figure 3.10). According to Eurostat's methodology, cooling days rely on the base temperature, the highest daily mean air temperature, not leading to indoor cooling. The base temperature value depends on several factors associated with the building and the surrounding environment. By using a general climatological approach, the base temperature is set to a constant value of 24°C in the Cooling Degree Days (CDD) calculation according to Eq. 3.9 (Eurostat, 2019a).

$$\text{If } \mathrm{T}im \geq 24°\mathrm{C}, \qquad \text{Then } [\mathrm{CDD} = \sum_i \mathrm{Tim} - 21°\mathrm{C}\,], \qquad \text{Else } [\mathrm{CDD} = 0]$$

Eq. 3.9

Where ‘Tim’ is the mean air temperature of the day ‘i'.

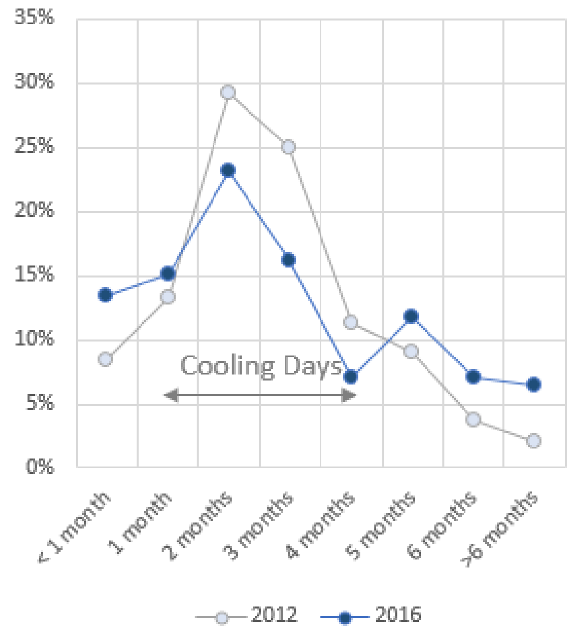


Figure 3.10: Distribution of months of use of cooling systems on the NIIs

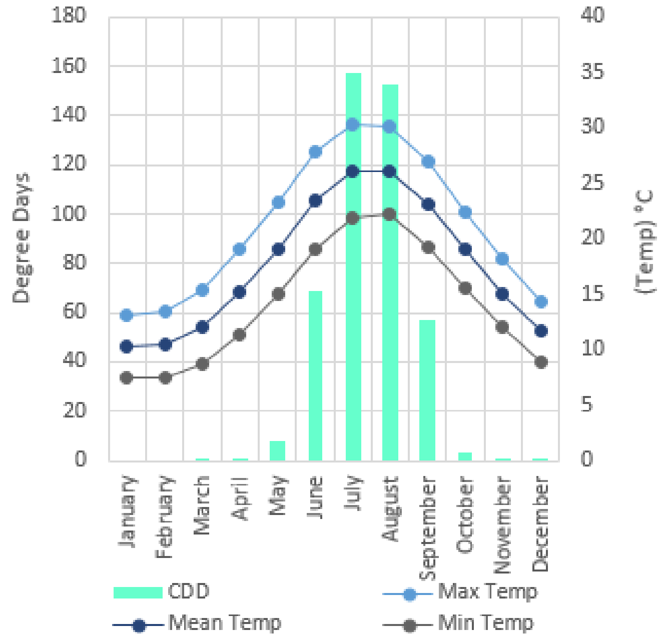


Figure 3.11: Max, Mean & Min temperatures and CDD on the NIIs

Four months were identified in all three IR to include CDD with Tim>24°C, namely June, July, August and September, according to monthly data provided by the Hellenic National Meteorological Service (2018) in Figure 3.11. July and August seem to require cooling for the majority of the days, while during June and September, the requirement for artificial cooling is reduced to 30%. Overall, the survey statistics prove that most households use air-conditioning within the months presenting cooling degree days while there is always a reasonable margin of ±1 month.

In 2016, despite reducing usage intensity within the frame between 2 and 4 months (Figure 3.10), there was an intensification in cooling demand for more than five months. The daily frequency for cooling devices ranges between 3 to 8 hours per day, mainly during the late morning and afternoon hours. Considerable temperature gaps during the day, greater than 6°C, imply that through night hours, temperatures on the islands drop with natural ventilation replacing the HVAC systems, a common practice in semi-urban and rural areas. In 2016, there was a reduction in the daily frequency of use compared to the 2012 level. While comparing 2012 with 2016 data, a trend towards decreasing the average use of

HVAC systems is encountered, despite the increase in units' installation. For estimating the technology-specific HVAC weighting factor for cooling purposes, we considered the growth of the electrification trend, the cooling systems technical attributes, the cooling degree days, the necessary improvements in the building envelope mainly related to thermal insulation according to directives of the KENAK Greek law (Gaglia *et al.*, 2007; Hellenic Republic - Ministry of the Environment and Energy, 2010a; Aravantinos *et al.*, 2017). Despite a clear trend for increasing utilisation of cooling aligned with the increase in temperatures, approximately 50% of the additional cooling demand is assumed to be offset by the improvements in the building envelope and replacing old inefficient devices beyond the impact reflected in the renovation scenarios. Therefore, the following weight factors assuming an Efficient and a Reference Scenario are adopted (Hellenic Republic - Ministry of the Environment and Energy, 2010a, 2017d, 2019b), additional to the regional demand:

Technology Specific Indicator – Space Cooling per Efficiency Scenario (%):

$$SC_{Efficient} = +0.11\%$$

$$SC_{Reference} = +0.17\%$$

The efficiency of HVAC systems in terms of cooling performance is measured as the Energy Efficiency Ratio (EER), which is the total cooling capacity to the effective power input of the unit, expressed in Watt/Watt (Eq. 3.10) (PennState College of Earth and Mineral Sciences, 2015). The systems were clustered into groups according to their energy class and the employment of inventor systems. The EER categories range between 2.6 (low-efficiency) and 3.35 (high-efficiency).

$$EER = \frac{q_c}{P}$$

Eq. 3.10

Where ‘q_c’ ‘is cooling energy per unit (Btu/hr)[22] *as specified in the SECH survey and ‘P’ is the power consumption (Watt)*

Since the utilisation time is provided as an average for the entire HVAC stock, we considered the same approach as in the heating sector; however, the utilisation in the auxiliary rooms is limited to 30% if the household residents exceed three.

The annual cooling requirements were calculated considering the monthly cooling days. If a month had cooling days defined by JRC (2018), the average daily use was assumed to be equal to the average hours of operating the cooling system. If the HVAC is equipped with a thermostat, it is assumed that it is operational only if the max outside temperature is higher for that CDD than the set temperature in the thermostat. The total electricity usage for HVAC cooling, as explicitly described in Eq. 3.11, is a sum of all the operational air conditioners within the household and is equal to:

$$Con\ HVACc_{hh}\ Total = \sum_{i}^{n} \frac{Annual\ Cooling\ Use * Coef_{use} * Unit\ Capacity}{EER}$$

Eq. 3.11

*Where ‘Annual Cooling Use’ is equal to Annual Cooling Days * Average Daily Use as defined above and ‘n’ is the total number of HVAC systems*

Electricity consumption by floor or ceiling fans was assumed to be calculated as follows:

$$Con\ AF_{hh}\ Total = \sum_{i}^{s} Unit\ Capacity * Annual\ Cooling\ Use * Coef_{use}$$

Eq. 3.12

Where ‘s’ is the hh number of Air Fans.

[22] 1 Btu = 2.931 x 10-4 kWh

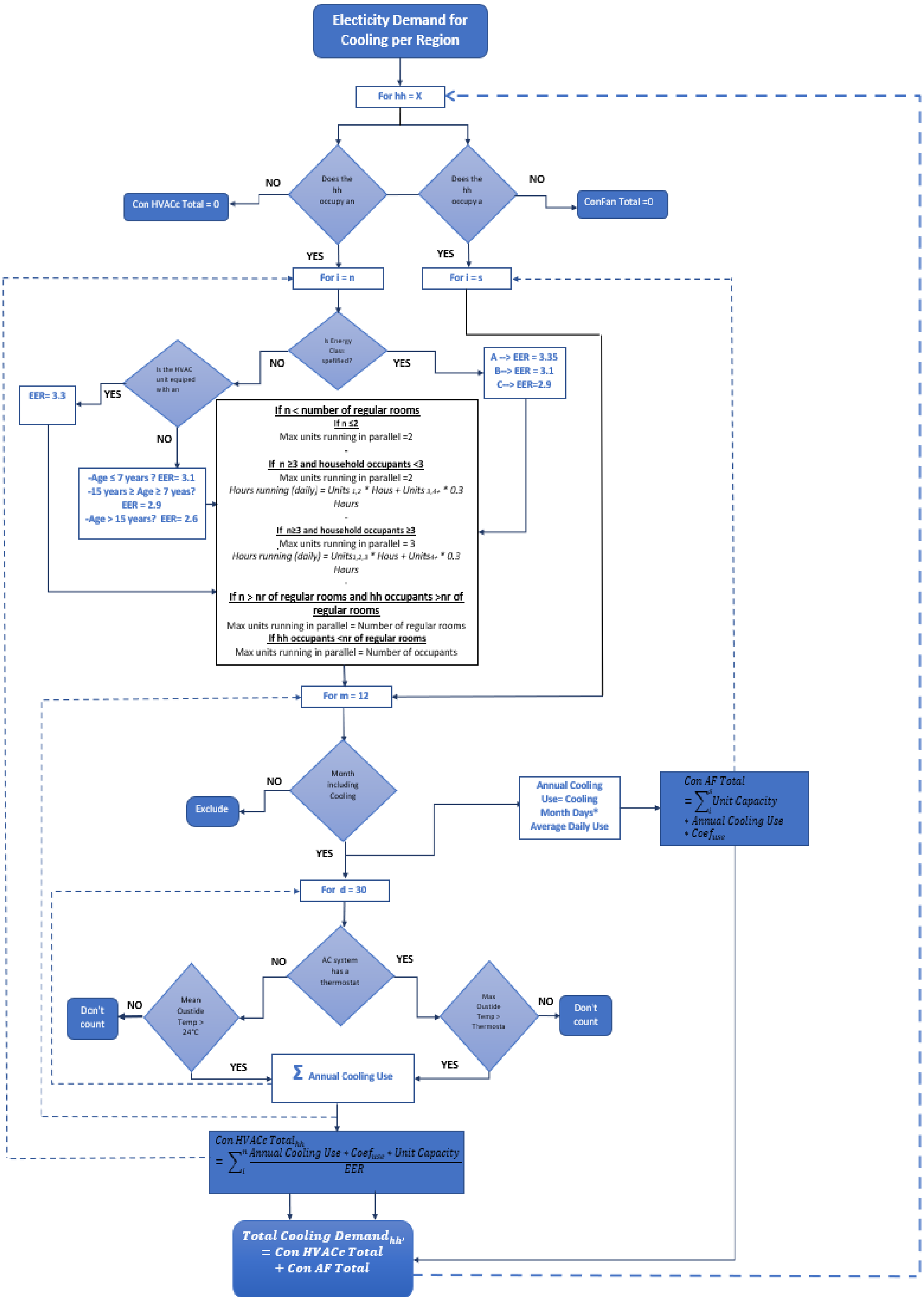


Figure 3.12: Flow chart of calculation of cooling electricity demand in the residential sector

3.3.2.3 *Water heating*

Energy for water heating is accountable for almost 6% of Greece's total energy demand. Participants in the survey located on the NIIs responded that they use Domestic Water Heating Systems (DWHS) to a degree of 97% (Hellenic Statistical Authority, 2013, 2016a). Greece and especially the southern parts enjoy abundant solar irradiation. Consequently, in 2012, 50% of the houses had installed solar water heating systems, which are energy-efficient systems providing hot water mainly during daytimes (Hellenic Statistical Authority, 2013). In this analysis, households occupying solar thermosiphon systems are assumed to cover 50% of their annual demand in 2016 (80% of their daily demand in the Summer and 20% in the Winter). By 2016, the houses with installed solar water heating systems increased to 59% (Hellenic Statistical Authority, 2016a), which shows a shift towards renewable energy systems as a cost-efficient option, as reflected in the modelling assumptions. Progressively 90% of the households by 2040 are assumed to install a solar system which will cover 60% of the daily water heating demand. Under such a case considering full deployment of energy efficiency policies, the Efficiency Scenario goes even beyond the National Energy Action Plan (NECP) directions (Hellenic Republic - Ministry of the Environment and Energy, 2018c, 2019b). Consequently, a technology-specific factor was inserted in the model to reduce the demand for hot water further:

Technology Specific Indicator - Water heating (%):

$$WHS_S = -60\% * AR_S$$

Eq. 3.13

Where:

'WHS' is the indicator related to the additional water heating solar system installed;

'S' is the renovation scenario;

'AR' is the annual renovation rate.

However, solar water heating systems cannot guarantee a continuous hot water supply around the clock. Therefore 35% of the users utilising solar thermosiphon have installed a conventional auxiliary system at their properties.

Most responders use electric thermosiphon systems (Figure 3.13), while half of those utilise them as their primary source for domestic water heating. Two-thirds of the electrical thermosiphons age more than ten years, amplifying inefficiencies while increasing operational and maintenance costs. 28% of the conventional water heating systems (boilers) are linked to the household's primary heating source.

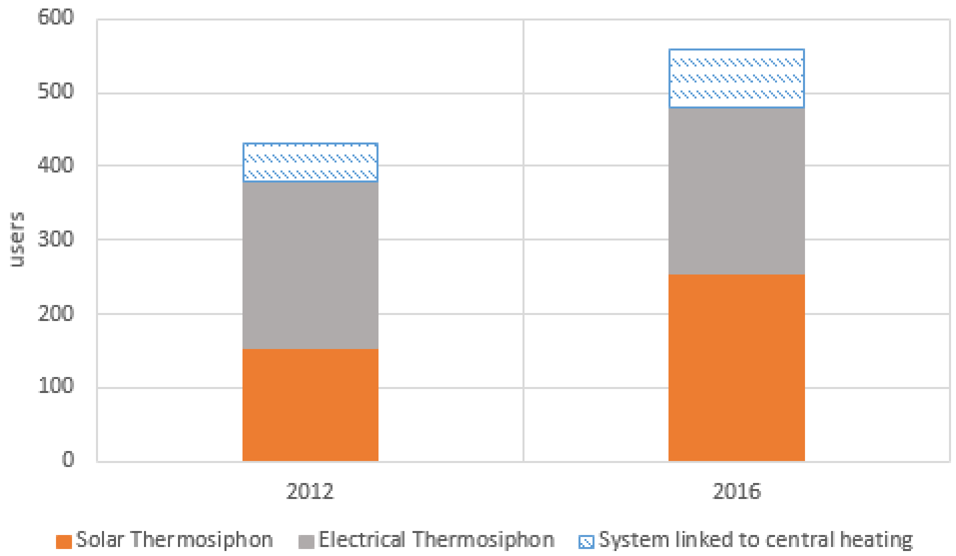


Figure 3.13: Total number of water heating systems installed in hh

The electricity demand for water heating is estimated throughout the year, considering the average daily uses (hours/day). The total demand for hot water ranges between 63 litres per day for households with one resident and 238 litres for households with eight residents, while the average consumption is 97.2 litres/day per household. Seasonal variations presuming the year is split into two seasons, summer and winter, are identified, as illustrated in Figure 3.14. The seasonal disparity of domestic hot water consumption is mainly attributed to the water temperature, creating a larger Delta over the winter months (Gerin, O.; Bleys, B.; De Cuyper, 2014). This assumption does not preclude the impact of outdoor air temperatures on water temperatures until they reach the desired comfort level (Burnazov and Apostolov, 2016).

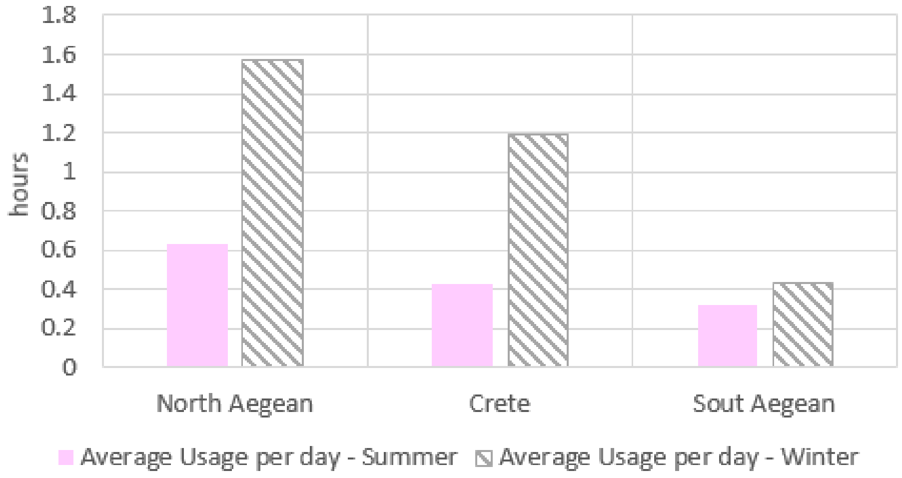


Figure 3.14: Average daily usage of electrical water heating systems per hh

The electricity consumption was calculated per hh and consequently per region, according to the seasonal average daily use of the electrical thermosiphon or boilers as depicted in Figure 3.15. In this context, 0.033 kWh is required to warm 1 litre of water up to 50°C, considering an initial water temperature equal to 15°C with a Delta of 35°C (PPC, 2016). It was assumed that each household had sized their water heating system to heat the volume of one buffer within one hour. The principal solution applied to calculate the electricity consumption for water heating is presented hereunder:

$$ConDWHS_{hh} = (Summer\ Usage + Winter\ Usage) * Buffer\ Capacity\ * 0.033\ kWh * Coef_{age} {}^{*}\ Coef_{use}$$

Eq. 3.14

Where:

'Summer and Winter Usage' is the seasonal sum of the average daily use in hours;

'Buffer Capacity' is the volume of the electrical thermosiphon in litres assuming 1h to heat the total volume;

'$Coef_{age}$' refers to an additional factor to reflect the age of the heating system and, therefore, its performance.

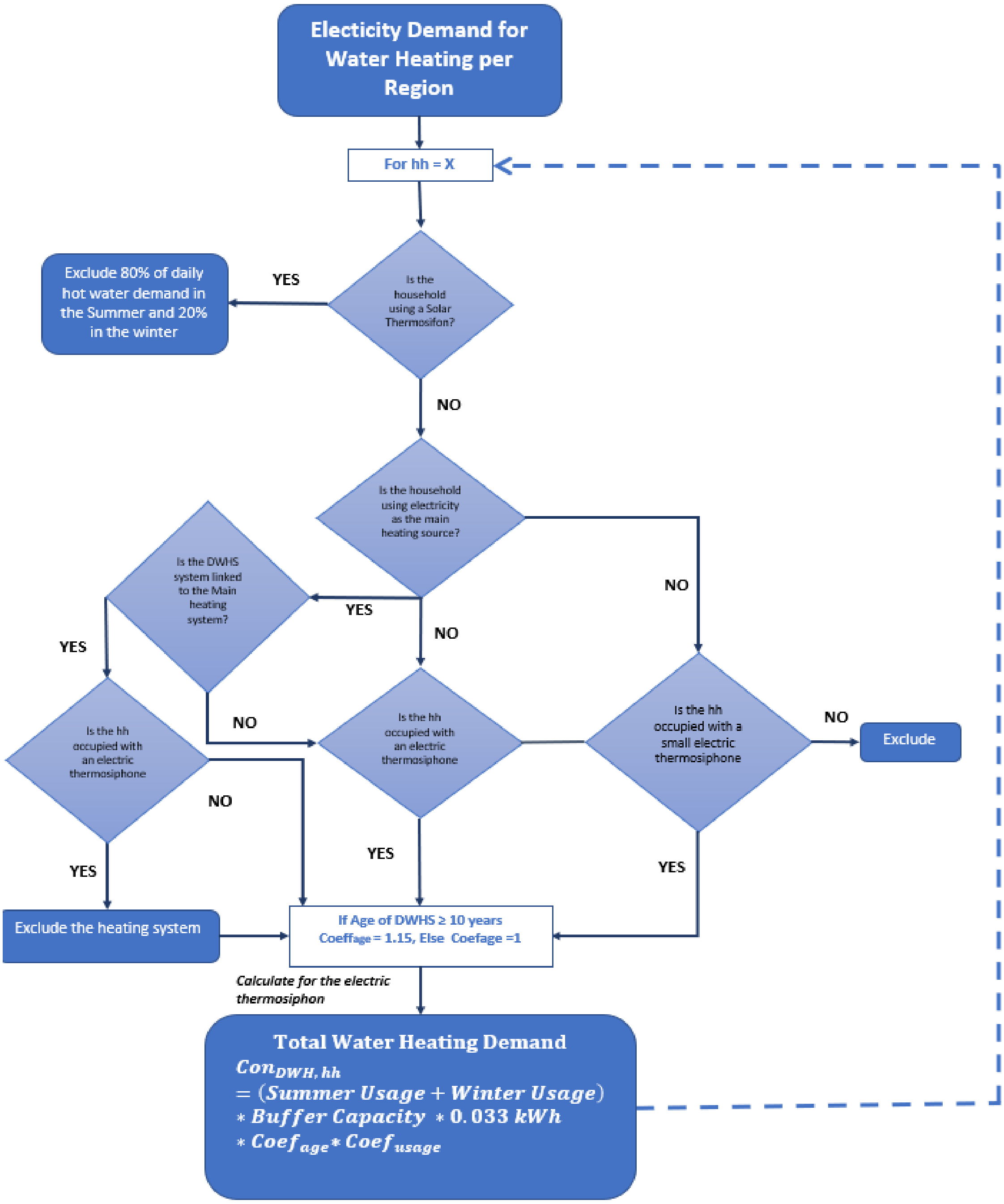


Figure 3.15: Flow chart for calculating water heating electricity demand in the residential sector

3.3.2.4 *Lighting*

The two questionnaires included six different types of lamps: Incandescent lamps, Halogène lamps (low wattage), Halogène lamps (high wattage higher than 70W), Fluorescent lamps, CFL (compact fluorescent lamps) and Light Emitting

Diode (LED). The Greek households use all these lamps with the occupancy rates presented in Figure 3.16. Households on the NIIs might use only one lighting bulb type, but usually, they combine more than one. The predominant type of lamp used is the Incandescent one. Incandescence lamps have the lowest energy efficiency as 90% of the energy is converted to unwanted heat and only 10% is converted to visible lighting; however, it was considered the optimum cost choice (Schwarz, Dimpl and Bandlamudi, 2006).

In 2016 there is a clear tendency to move towards more efficient lamps, such as LED technology growing from 1.5% to 18%. Respectively, the inefficient incandescent lamps are lowering by 20% from 51% to 31%. Small halogen lamps are reduced by 5%, while larger halogen lamps show a small increase of 2%. On the other hand, CFL is increasing by 5% as an efficient option. Fluorescent bulbs are determined to be used for specific uses to keep the same proportion.

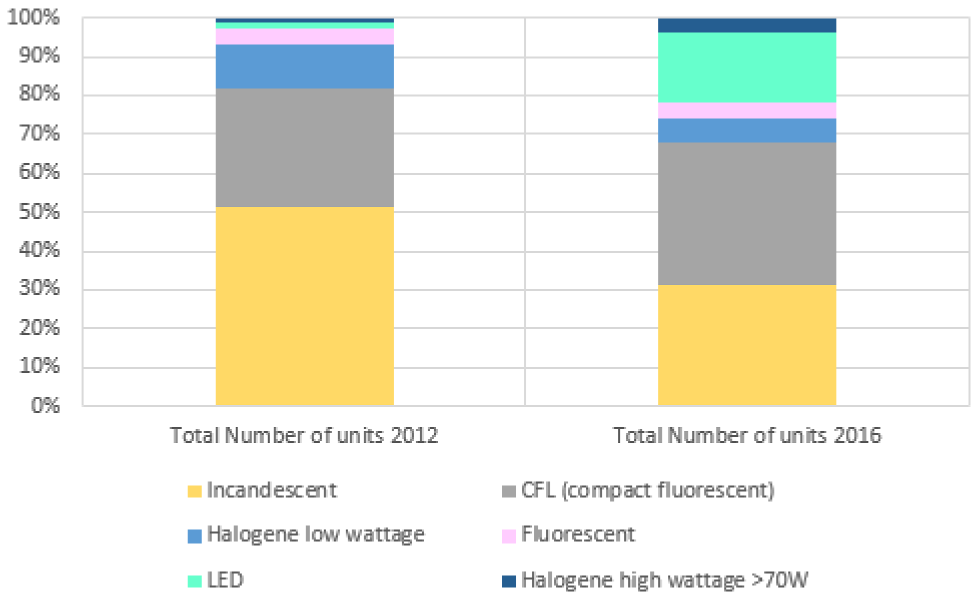


Figure 3.16: Occupancy share of lighting bulbs in hh

The efficiency of a lighting bulb is measured as the efficiency of a device in converting electrical power to visible light in lumens/watt or lux/watt (Schwarz, Dimpl and Bandlamudi, 2006). More information on the efficiency of lighting bulbs covered by this survey is presented in Table 3.3.

Table 3.3: Characteristics of the key types of residential lighting (The Carbon Trust, 2012; Energy Star, 2013)

Category	Lump Type	Efficacy lumens/watt	Lifetime (hours)
A	CFL (compact fluorescent)	45 – 70	6,000 – 15,000
B	Fluorescent	38 – 106	15,000 – 20,000
C	Halogene high wattage >70W	16 – 26	3,000 – 8,000
D	Halogene low wattage	13 – 18	2,000 – 6,000
E	Incandescent	6 – 14	1,000
F	LED	25-100	12,000 - 50,000

Incandescence lamps, including conventional incandescent bulbs and conventional halogen bulbs, have been banned since 2008, according to EU regulation No 244/2009 (European Parliament, 2009). The period of phasing out of these types of lamps was between 2009 and 2012, which implies that incandescent lamps were still utilised during the reference period of this survey (European Commission, 2009). In parallel, the EU regulation 1194/2012 was established concerning eco-design requirements for directional lamps, light-emitting diode lamps and related equipment (European Commission, 2012). The second most frequently used type of lamp is the CFL, an improved version of fluorescent lamps with a longer lifetime and higher efficiency while providing the same quality of light. Fluorescent lighting bulbs have a small share as they are usually used in residential garages and auxiliary spaces for all-purpose lighting. However, they are remarkably efficient and enduring (The Carbon Trust, 2012; Energy Star, 2013). Halogen bulbs with low voltage are the third preferable option. As of September 2018, standard halogen lighting bulbs with non-directional light (mainly the pear-shaped ones) have likewise been phased out. The European Commission proposed replacing halogen bulbs with LED light bulbs, considered the safest, most affordable and energy-efficient alternative (European Commission, 2018b).

The utilisation and the illumination of natural daylight in the area as well as hh occupancy rates are some of the factors upon which the electricity consumption of light appliances relies. Daylight is dependent on the openings in the house, types of lighting bulbs utilised in a household, the occupations of household members, and the room's number and spaces. In this analysis, we utilised the available information on the number of lighting bulbs available in the household, their type, and their wattage (*LaW*). Nevertheless, as the usage pattern was unavailable, many assumptions have been adopted to reflect different household usage rates.

The required lighting is estimated according to:

$$PowL = \frac{D_L}{L_S}$$

Eq. 3.15

Where 'D_L' is the required, artificial light measured in lumens and 'L_S' is the luminous efficacy (lumens/watts) of the different bulb types.

The households were split into economically active households, pinpointed by the hh head under employment, and households where the household head is either in retirement or in the unemployment stage. Another determinant factor is the sunrise and sunset hours. According to the 'Daylight Saving Time System', the year is split into two main seasons: summer and winter.[23] Due to natural sunshine and high amounts of solar irradiation on the Greek islands, daytime lighting is expected to be minimal, as dwellings are typically constructed with wide openings to take advantage of the long hours of sunlight.

[23] Potential changes in the daylight following the EU parliament vote to stop the twice-yearly change of time were not considered in this analysis, due to the ambiguity of the application of that directive.

The sunrise and sunset times are set according to the following data (Time and Date, 2018):

<u>Winter Time Season (November-March):</u> Sunrise→ 7:30, Sunset → 18:00

<u>Summer Time Season (April-October):</u> Sunrise → 7:00, Sunset → 20:00

For those hh that are economically active, the following assumptions were integrated into the analysis to determine the weight factors for daily lighting usage ($Pl_{h,a}$) where 'h' represents the sunset or daylight and 'a' represents the activity status of the dwelling occupants on an annual basis:

- $Pl_{h,a}$ = 0% [when h= sunset, a = household residents sleeping or non-present, 23:00-6:00]
- $Pl_{h,a}$ = 30% [when h=daylight, a= household residents active, 6:00-9:00]
- $Pl_{h,a}$= 15% [when h=daylight, a= economically dependent residents active, 9:00-sunset time]
- $Pl_{h,a}$ = 80% [when h=sunset, a= household residents active, sunset time - 23:00]

For those hh economically inactive, the following assumptions were integrated into the analysis:

- $Pl_{h,a}$ = 0% [when h= sunset, a = household residents sleeping or non-present, 23:00-sunrise time]
- $Pl_{h,a}$ = 30% [when h=daylight, a= household residents active, sunrise - sunset]
- $Pl_{h,a}$ = 80% [when h=sunset, a= household residents active, sunset time - 23:00]

No differentiation between weekdays and Saturdays was assumed, as it was not possible to identify the different activities performed during that day. For Sunday, considering only economically active homes, the $Pl_{daylight,\ residents\ active}$ was considered 40%. As described in the previous sections, the usage coefficients were also applicable for lighting appliances.

The electricity consumption (ConL) for lighting appliances of type L and total number (l) was calculated according to:

$$ConL_{hh}Total = \sum_{i}^{L} Active\ hours\ year * \ Coef_{use} * LaW_{L}$$

Eq. 3.16

Where:

$$Active\ hours\ year = Active\ hours\ year_{active\ hh} + Active\ hours\ year_{\ inactive\ hh}$$

Eq. 3.17

$$Active\ hours\ year_{status\ \ hh} = \sum_{d=1}^{365} (\sum\nolimits_{h=1}^{24} * Pl_{h,a})$$

Eq. 3.18

The analytical steps followed to calculate the total, and average hh demand are illustrated in Figure 3.17.

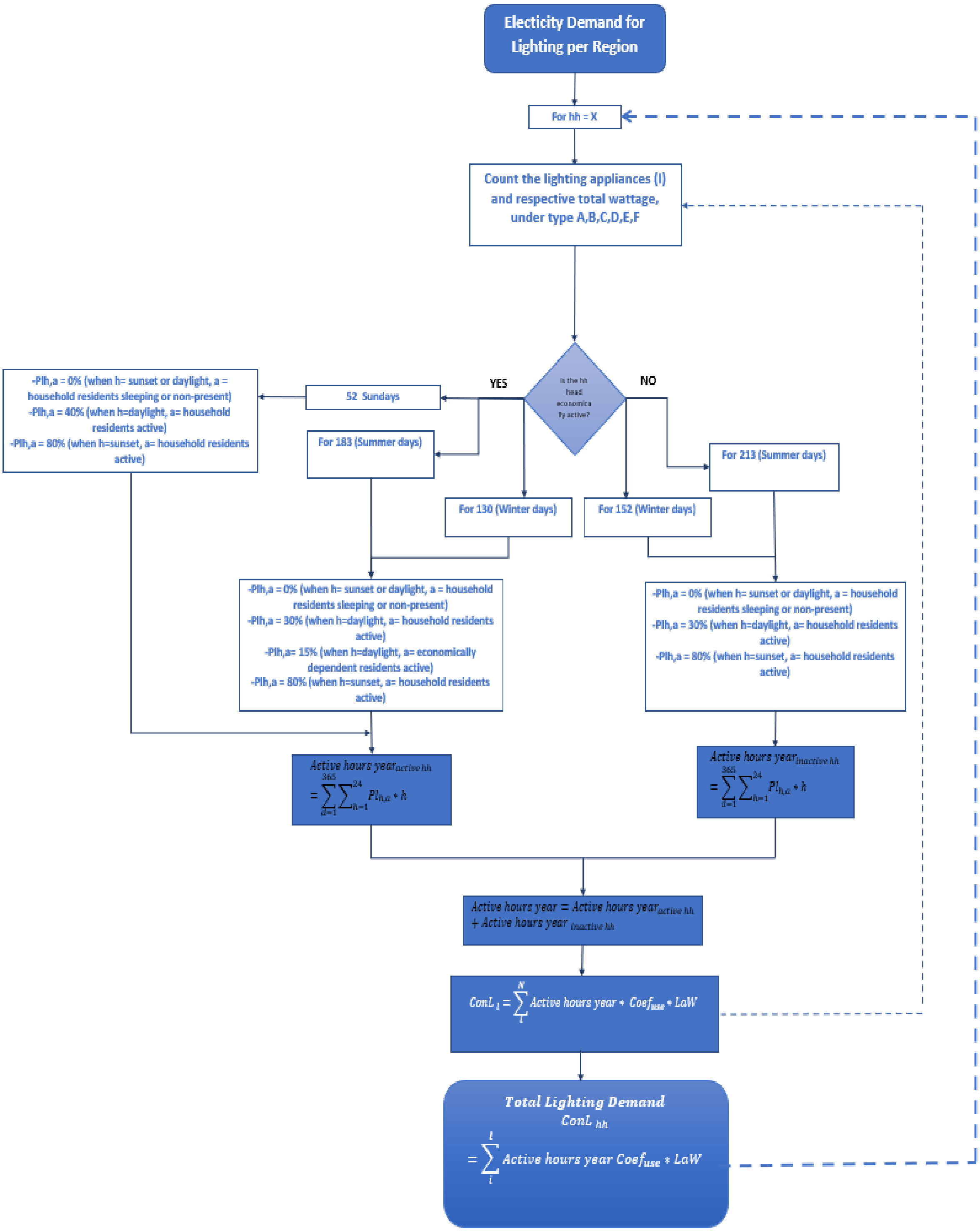


Figure 3.17: Flow Chart for calculating lighting electricity demand in the residential sector

3.3.3 Demand profiles of non-weather dependent electrical uses

3.3.3.1 *Appliances*

Household electrical appliances, excluding cooking appliances, are accountable for more than 10.2% of the total energy demand in a house and more than 26% of the electricity demand (Hellenic Statistical Authority, 2013, 2016a). For this study, devices were split into the following categories:

Table 3.4: Categories of hh electrical appliances

Group	Appliance
Freezing	Fridge freezer
	Fridge without freezer
	Freezer (separate)
	Water cooler
Washing	Dishwasher
	Washer
	Tumble dryer (separate)
	Washer dryer
Cleaning/Ironing	Iron
	Vacuum cleaner
Entertainment	Television
	Home cinema
	DVD
	Projector
	Video game console
	Stereo
Other devices	Satellite antenna
	Decoder
	Computer (desktop, laptop, etc.)
	Peripheral devices (printer, scanner, etc.)
	Internet devices (modem, router, etc.)

Every household in the three regions is equipped with at least one **fridge,** while only 2% have more than one. The average age of the fridge represents that most appliances are between 9 and 15 years old. Considering that labelling began in 2000, most freezing appliances are outdated. Except for Crete reporting 57% of freezing appliances being Energy Class A, North and South Aegean peripheries report less than 20% in this class. As anticipated, households that reported Energy Class A fridges appear in the higher-level income scale. Results from 2016 show that every household is equipped with at least one fridge, while 3.6% have more than one. The average age or energy efficiency labelling is not provided in the SHFB survey. The freezing appliances are assumed to be plugged in 24 hours a day.

One-third of households use **dishwashers**, aged between 3 and 15 years old. Their age designates a considerable margin for renewing the stock. Nevertheless, Energy Class A was identified in devices of less than 15 years. The occupants of households use dishwashers from 1 to 7 times per week with an average duration of 1.25 hours, matching the average length of a dishwasher programme of older machines or a new machine's fast/economy cycle (GE Appliances, 2019) (Figure 3.18). The 2016 study results are limited in terms of hourly use of the dishwasher; therefore, no concrete conclusions can be drawn from the comparison of the two surveys.

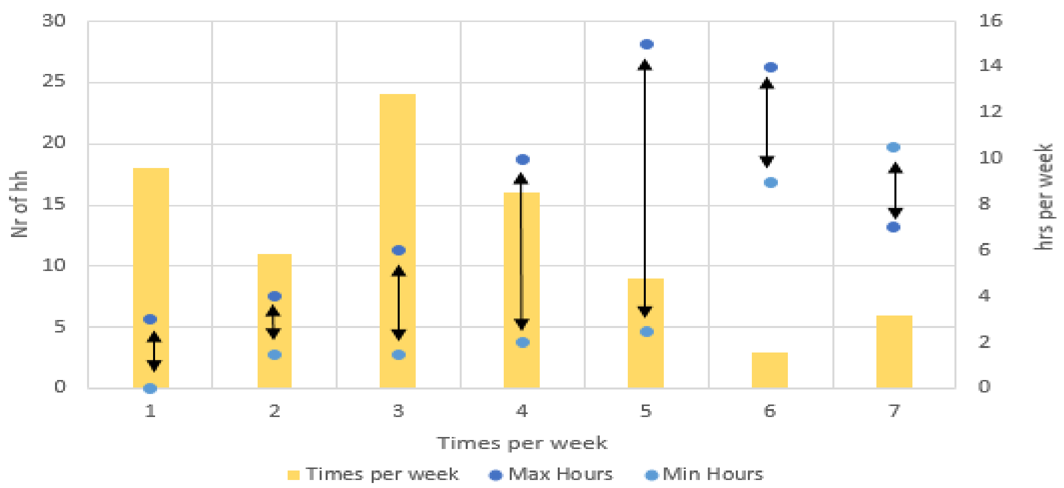


Figure 3.18: Frequency of dishwashers use

96% of the participants responded that they possess a **washer** or a **washer/dryer**. Only 3% use separate **dryers** since Greece's favourable weather conditions allow drying clothes outdoors. 40% of the responders claimed that they are using A-class equipment, while more than 50% are unaware of the energy class of their washing machines. Most users operate their washing machines twice per week (Figure 3.19). The average time per use is 1 hour in line with the minimum cycle of most washing machines older than five years. Based on the 2016 survey, 99.5% responded that they possess a washer or a washer/dryer, while 5% reported using a separate drier showing an increasing trend with time.

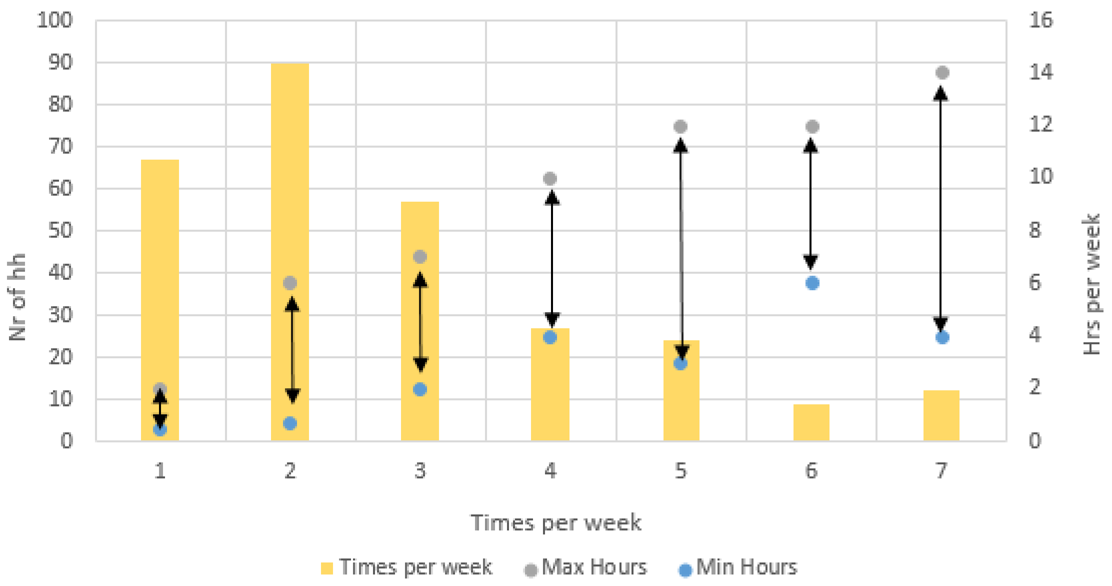


Figure 3.19: Frequency of washers and washers/driers use

90% of the households possess at least an **iron** in both surveys, while the income discrepancy seems relatively small. 87% of the ironing devices are between 3 and 15 years old. Most households use iron between 1 and 2 times per week (Figure 3.20). The data from the survey of Greek households reported using **vacuum cleaners** in a proportion of 71%. The majority of the houses use vacuums once per week for less than an hour, but in some cases, the frequency of vacuum cleaners increases in households with more than three permanent residents

(Figure 3.21). The Greek households interviewed in 2016 reported using vacuum cleaners in a proportion of 88%, revealing the small impact of the economic crisis in such small devices.

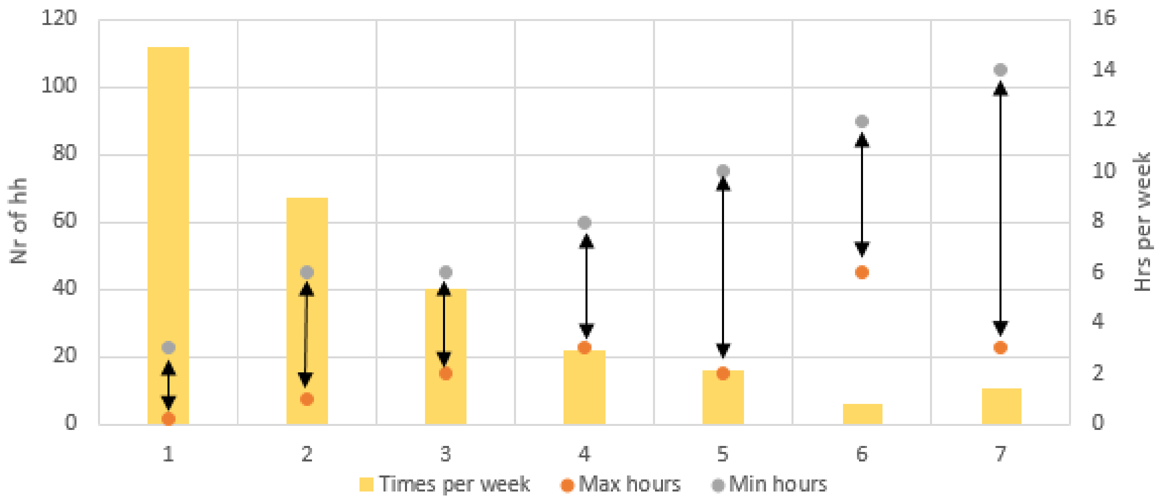


Figure 3.20: Frequency of irons use

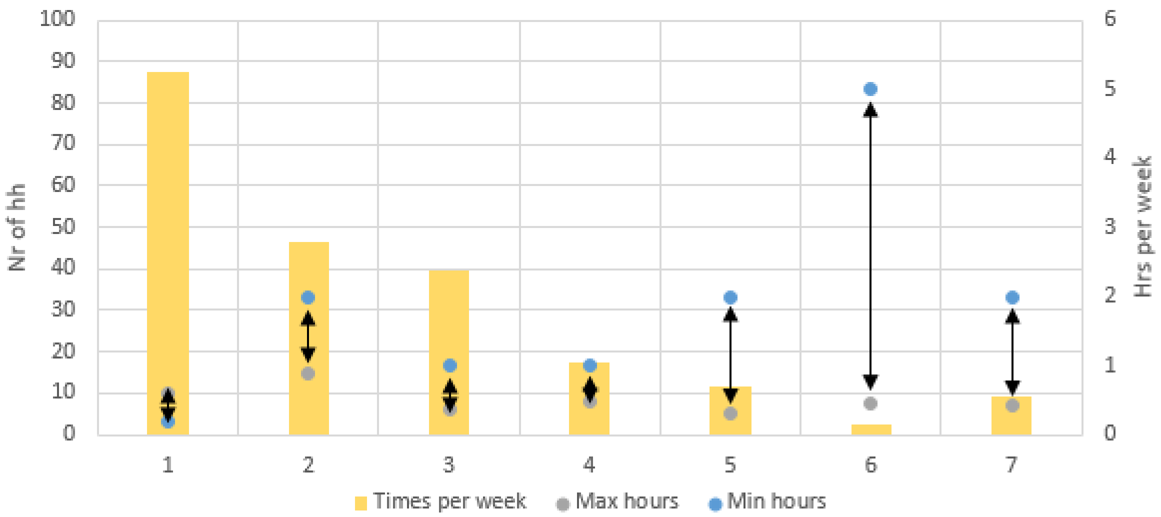


Figure 3.21: Frequency of vacuum cleaners use

Entertainment devices incorporate television (TVs), DVDs, home cinemas, projectors, video game consoles and stereos. 99% of the households possess at least one TV, while the average ratio is equal to 1.4 TVs per house. Considering the rest of the devices, a few households (8-10%) possess a Home Cinema or a video console mainly connected to higher-income families. Regarding DVD and stereos, as they tend to become less popular or have been replaced by other devices, they are recording low stock among the survey participants, a trend which is expected to eliminate their use.

The distribution of the TVs' age unveils similar trends as the rest of the appliances. However, in the case of TVs, more items are classified under the 'new' group 0-6 years, showing the tendency to replace faster TVs. TVs are used on average 34 hours per week or roughly 5 hours per day, according to Figure 3.22. However, it is notable that households report TVs use for 120 hours per week, implying that the device remains on for the whole period the occupants are awake—these concern mainly inactive residents. The rest of the entertainment appliances report rationale uses, except for video consoles, with almost 60 hours of usage per week. Entertainment electric appliances are also accountable for consuming energy in standby mode (Figure 3.23). In the SHFB survey, the occupancy rates for video consoles increased from 8.5% in 2012 to 17.9% in 2016. DVD ownership is reduced (5.8% vs 24.6% in 2012) as they tend to become less popular or replaced by other devices and platforms.

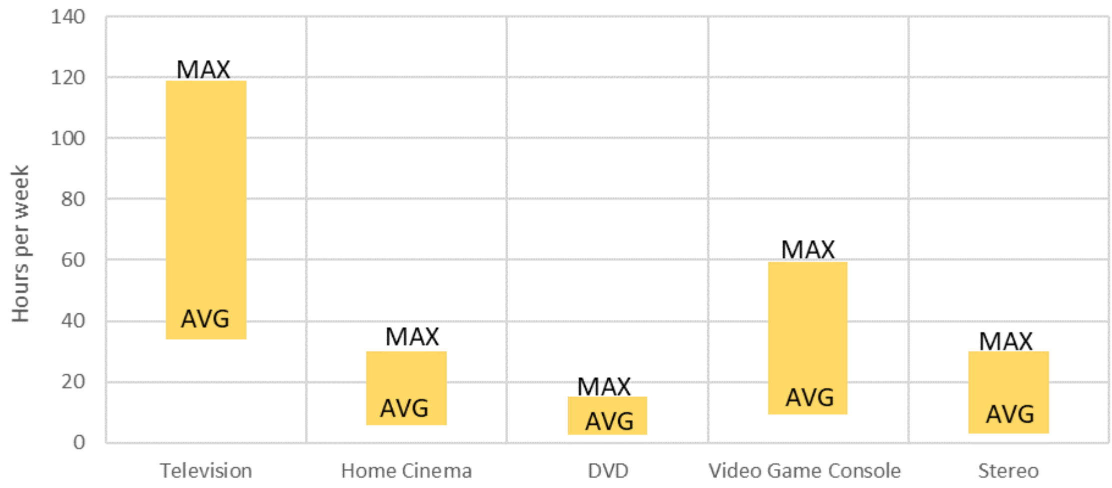


Figure 3.22: Average and maximum values of entertainment equipment use per week

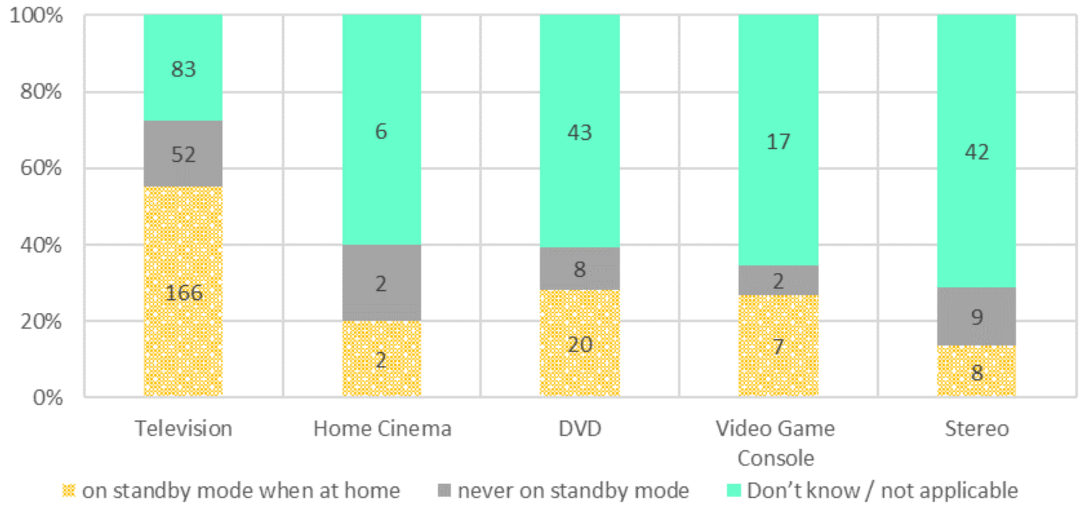


Figure 3.23: Distribution of standby mode use by an appliance

The rest of the devices concern: satellite antennas, decoders, computers (desktop, laptop, etc., peripheral devices (printer, scanner, etc.) and internet devices (modem, router, etc.). 40% of the households have their own internet devices, assuming that by 2025 100% of the households will have access to the internet. Furthermore, computers are found in more than half of households. The actual use of devices was requested from the responders only for computers and peripheral devices, while their use was not easily traceable for the rest of their devices. As per the 2016 survey, 62% of the responders occupy at least one computer. However, peripheral devices are occupied by 18% of the households versus 11% in 2012, showing overall a tendency to consume more computer and peripheral devices with time. In this analysis, a weight factor is applied, linked to the age of each appliance, assuming a relevant degradation in the energy efficiency standards through time, considering data from the European Commission (2012); Environmental and Energy Study Institute (2017); 52 Climate Actions (2018) and IEA (2020). The total annual energy consumption in the appliance category (app) and per hh is calculated according to Eq. 3.19. The total electricity consumed is the sum of all appliances per category per hh, as presented in Figure 3.24.

$$ConAPP_{hh} = \sum_{i}^{A} Cap_{app} * Freq_{app} * Dur_{app} * Coefage_{app}$$

Eq. 3.19

Where:

'A' is the total number of that specific type of appliance (app);

'Cap' is the assumed capacity (Watt);

'Freq' is the average weekly frequency extrapolated in a year for that type of appliance per hh;

'Dur' is the average duration of each use of that appliance.

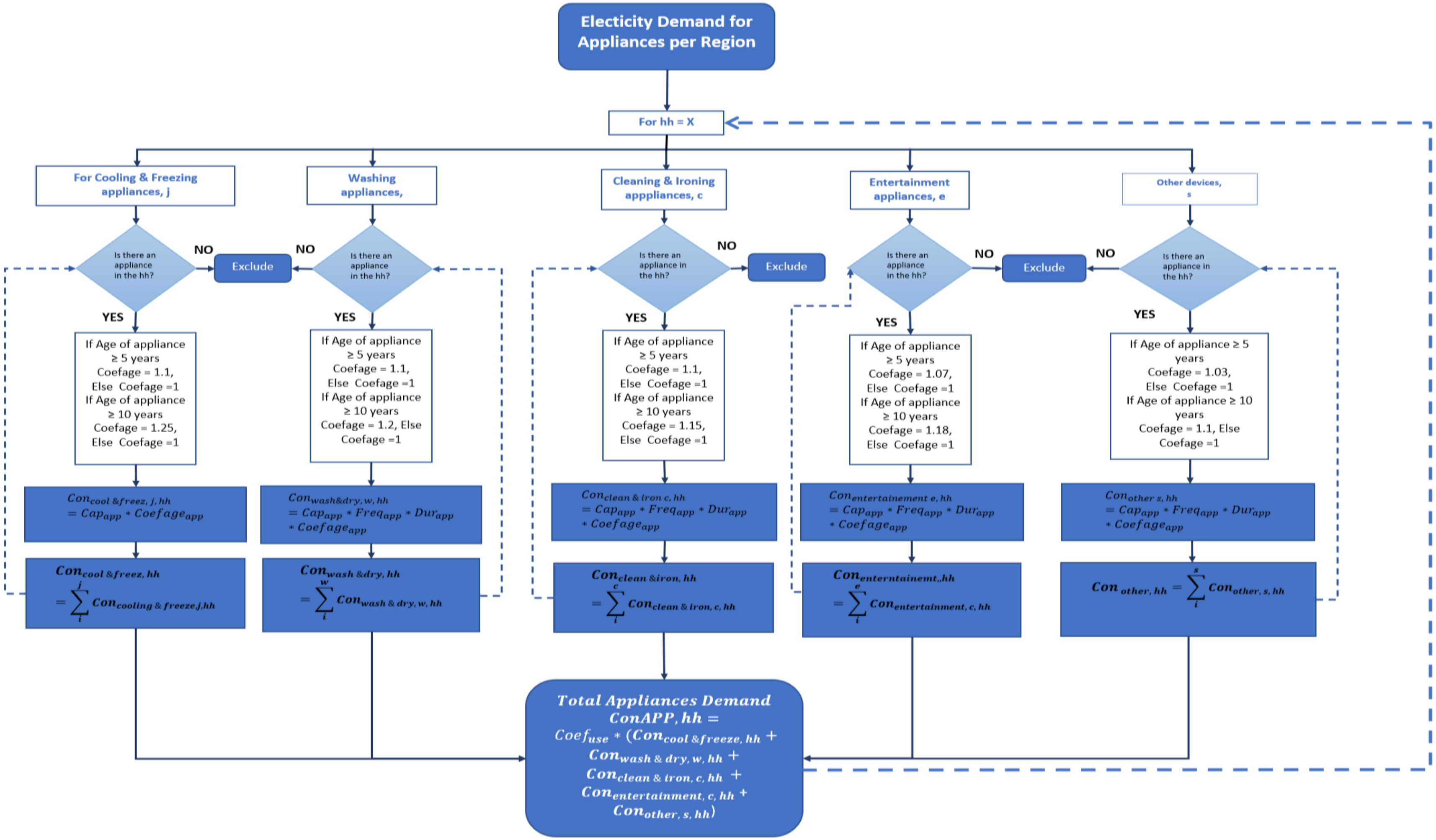


Figure 3.24: Flow chart for calculating appliances electricity demand in the residential sector

3.3.3.2 *Cooking*

Cooking is considered an individual category within the survey, including domestic devices, as indicated in Table 3.5. All households are occupied with hobs, and over 90% use ovens and cooker hoods. The predominant source for powering hobs is electricity (98%), and the rest of the cooking appliances are considered purely electric. The primary sources used for powering ovens are electricity and gas in Liquid Petroleum Gas (LPG) form, with a ratio of 85% and 15%, respectively. Higher-income households record high occupancy rates in small auxiliary appliances. Since no indication about the capacity of these small appliances and the energy consumption is available, the assumptions used data from the literature. Regarding cooking hoods, ducted range hoods are assumed to be used. Hoods consume electricity for their primary use, but usually, they are also equipped with lighting bulbs.

The weekly frequency range of usage of cooking appliances varies, as indicated in Figure 3.25. 55% of the households use their hobs at least once per day. 35% use their ovens 3-6 times per week for 3 hours each time and 35% for less than two times for the same duration. 62% of the residences with more than three occupants use their cooking appliances daily. Regarding those households with one or two occupants, such uses are limited to twice per week or even more rarely. The occupancy rates overlap between 2012 and 2016; however, microwaves present an increasing trend underlining the partial replacement of electric ovens in everyday use. The frequency usage scale was translated into absolute numbers for the analysis, taking the given range's average and extrapolating it to an annual level.

Table 3.5: Cooking appliances average power consumption (European Comission, 2002; Hellenic Statistical Authority, 2013; PPC, 2016)

Category	Appliance	Capacity (kW)
Cooking	Hobs (big)	2
	Hobs (medium)	1.5
	Oven	2.7
	Water boiler	1.2
	Toaster	0.6
	Coffee Maker	1.3
	Microwave	0.06
	Cooker Hoods	0.1
	Fireplace	Non-electric
	Woodstove	Non-electric

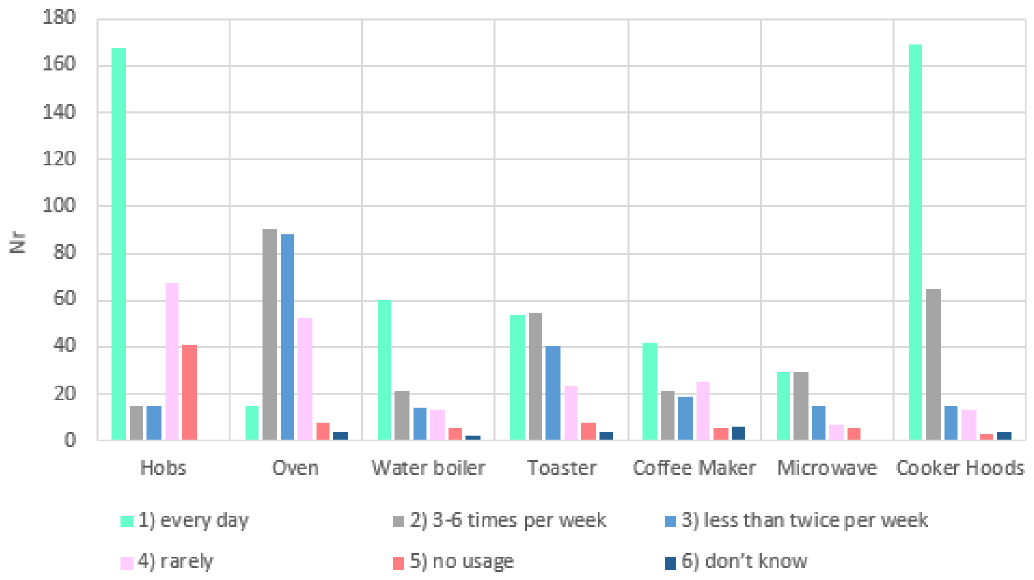


Figure 3.25: Frequency of cooking appliances use

Cooking appliances such as ovens, hobs and range hoods are also subjected to EU energy labelling and eco-design requirements. The field for reporting the energy class of the appliances had often remained empty in the SECH survey, where the age of appliances was considered a criterion for categorising their energy efficiency. Nevertheless, little was identified in the literature regarding the correlation between small appliances' age and degradation through time. Assuming that a product counting ten or more years in use will be categorised at least as a product of class C, older appliances will consume 15% more as regards coffee makers, water boilers and toasters, while for ovens, a 21% indicator was assumed and 18% for hobs according to (European Comission, 2002; Hellenic Statistical Authority, 2013). Although a more gradual de-escalation of efficiency could be adopted, the approach mentioned above is considered sufficient, given the limited impact of these appliances on final electricity consumption. The analysis steps are illustrated in Figure 3.26, showing that every household's annual consumption per appliance was calculated based on the frequency usage, power consumption of appliances, and age amplifiers (Eq. 3.20). Finally, the total consumption for cooking purposes is the sum of all the cooking appliances' annual consumptions[24], considering the usage coefficient.

$$ConCAPP_{hh} = \sum_{i}^{C} Cap_{Capp} * Dur_{Capp} * CoeFage_{Capp} * Freq_{Capp}$$

Eq. 3.20

Where 'C' is the type of the cooking appliance;

'Cap' is the assumed capacity for that type of appliance (Watt);

'Freq' is the average weekly frequency extrapolated in a year for that type of appliance per hh;

'Dur' is the average duration per time of use.

[24] No more than one operational cooking appliance under each category was reported per hh

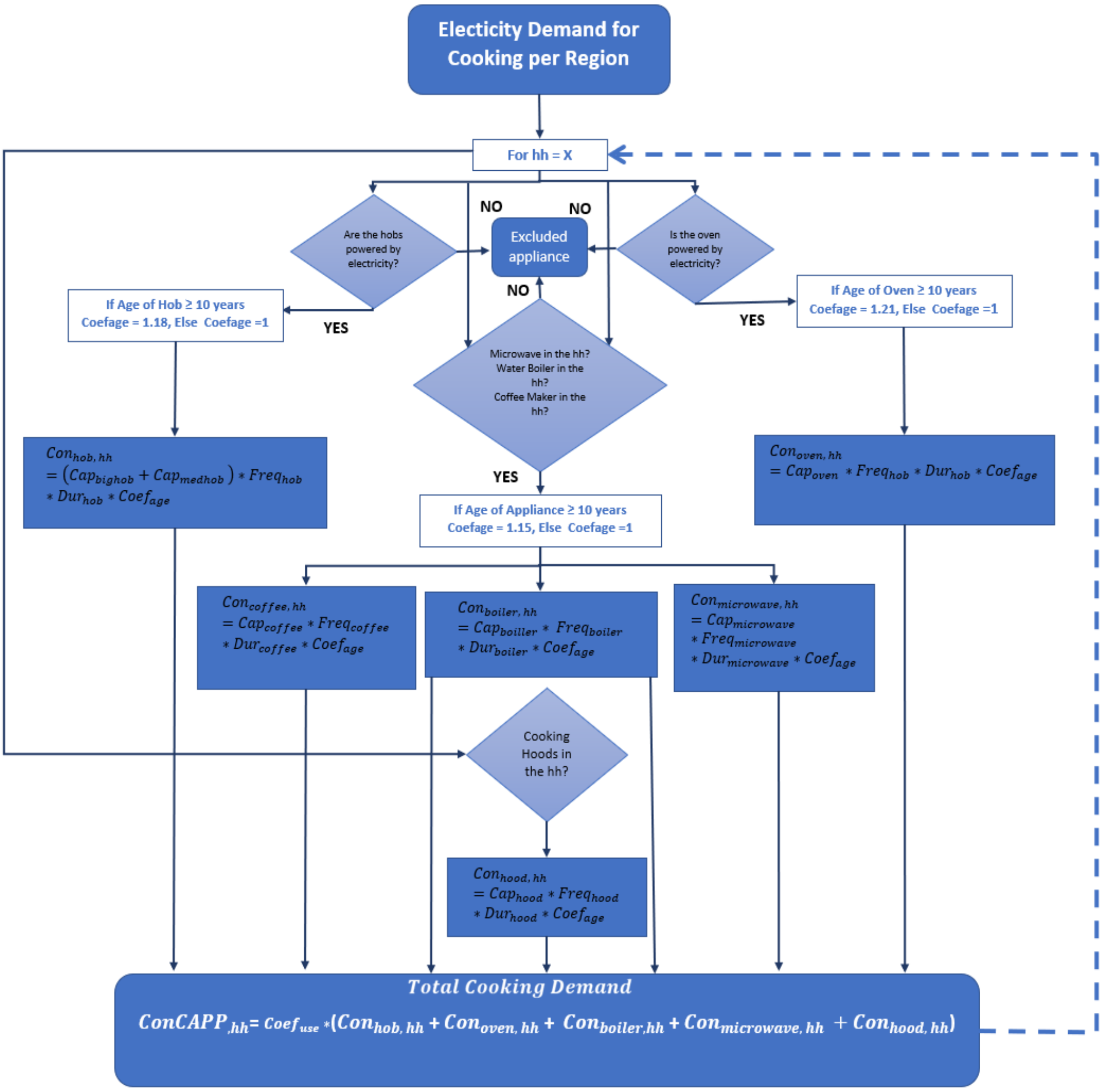


Figure 3.26: Flow chart for calculating electricity demand for cooking in the residential sector

3.3.4 Demand breakdown

The annual residential demand profile was configured following a bottom-up analysis of the SECH survey data. For each IR, the electricity end-uses of space heating and cooling, water heating, lighting, appliances and cooking were summed up and extrapolated to the entire islands' population levels. While comparing the SECH with SHFB survey statistics, we proposed the valid assumption that the residential demand breakdown (%) per end-use in 2012 will also be relevant for 2016, considering the proximity of those two years. Therefore, the breakdown of residential electricity sub-uses was calculated, given each autonomous system's 2016 aggregated residential demand.

Figure 3.27 illustrates the residential demand split per region, demonstrating that cooking is the leading residential consumer ranging between 31% and 33%, followed by electric appliances, accountable for 20-27% of the total electricity demand. The rest of the demand is attributed to water heating, lighting, space heating and cooling. In the South Aegean Sea, there is a 13% share for cooling and heating purposes and 12% for water heating which is lower than the other regions due to lower occupancy of electrical thermosiphons. The regional data fluctuate at the same levels as the national ones except for water heating which records almost double figures against cooking, with approximately 5-7% lower shares. This is explained firstly by the relatively lower numbers of solar water heating systems installed on the Greek islands due to architectural constraints and secondly due to a considerable proportion of households using LPG for cooking, which is not the case in the continental part of Greece.

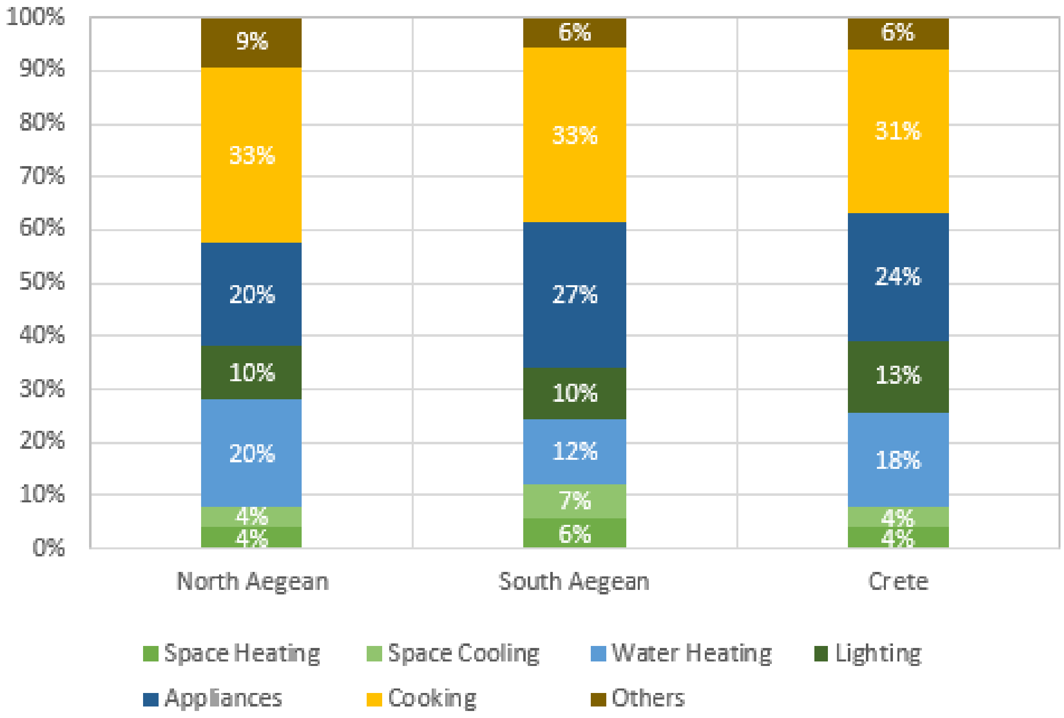


Figure 3.27: Residential electricity demand share per IR

3.3.5 Demand scenarios

3.3.5.1 *Socio-economic driven*

Top-down multilinear regression analysis was applied to calculate the annual residential demand growth, which typically relies on the electricity demand's correlation with one or more socio-economic, demographic, or meteorological parameters. The residential demand (dg_{RES}), according to Eq. 3.2 is considered a dependent variable *(y),* and the independent variables (*x)* are indicated in Eq. 3.21.

$$dg_{Res,r} = \alpha_r x_{1,r} + \beta_r x_{2,r} + \gamma_r x_{3,r} + \delta_R$$

Eq. 3.21

Where the multipliers *α, β, γ* are the regression coefficients related to population, household size, and GDP, respectively, represented as $x_{1,2,3,}$ and δ is the regression constant for the multiple linear regression model linked to each region (R). The three dependent variables were selected as predictors for future electricity demand projections up to 2040 as they were identified to be closely linked with household electricity and energy-consuming activities (Çunkaş and Altun, 2010).

Specifically:

- **GDP** shows the size of a region's economic activity and economic conditions and has been diversified with two scenarios.
- Electricity demand generally increases in proportion to the **Population**.
- **The number of households** is considered an essential indicator due to several appliances in a single household.

Other indicators identified in the literature are electricity and fuel prices. Electricity prices are an outcome of the overall electricity system analysis; therefore, it remained out of the multiple regression analysis to avoid circular references within the model. Moreover, electricity prices have been ignored as the islands pay a uniform national price through the PSO policy.

The ISLA_EGI model's population growth was forecasted following the latest projections (Eurostat 2018). Figures were identified at a NUTS -2 level aligned with the geographical granularity proposed by the household surveys.

Population projections concerning Greece at a national level are not pinned down to a regional level. Therefore, projections for the three primary island geographical regions were calculated using a polynomial regression analysis considering 15-year data between 2002 and 2016.

The R-squared (R^2) factor indicates how close the data are to the fitted regression equation. The definition of R^2 is the percentage of the variation of the response variable that a linear model explains. The analysis shows that the model fits the data at a satisfactory level. For Crete, a second-level polynomial equation was utilised with an R^2 equal to 0.87, demonstrating a good fit. For South and North Aegean, the polynomial equation level was increased to a 4th and 3rd degree, respectively, to reduce the variance between the residual and the fitted line plot without distorting the predictors. Except for North Aegean, Crete, and South Aegean demonstrate a satisfactory R^2. Remarkably, North Aegean was affected by mass immigration waves distorting the native population figures, which the models cannot predict. By running the ANOVA test (Eq. 3.22), F values are higher than the F critical values; the null hypothesis is rejected, so the regression analysis is approved. Table 3.6 presents the annual population growth factors per IR.

$$F = \frac{\sum_{i=1}^{r} (\bar{Y}_i - \bar{Y})^2 \big/ {r-1}}{\sum_{i=1}^{r} \sum_{j=1}^{n_i} (Y_{i,j} - \bar{Y}_i)^2 \big/ {n-r}}$$

Eq. 3.22

Where:

'Y_i' is the sample mean of group 'I';

'n' is the overall sample size;

$\overline{'Y'}$ is the overall data mean;

'r' is the number of dependent variables;

'$Y_{i,j}$' is the observation 'j' in group 'I' out of the 'r' independent variables.

Table 3.6: Population growth ($Popgrowth_{IR,y}$)

Indicator	**Island Region (NUTS-2)**		
	Crete	South Aegean	North Aegean
Annual Population Growth (2020-2029)	0.13%	0.13%	0.07%
Annual Population Growth (2030-2040)	0.15%	0.19%	0.04%

Population, average household size and household numbers are calculated in Eq. 3.23, Eq. 3.23 and Eq.3.24 (Spataru, 2013) for each island's geographical population.

$$Population_{R,y} = Population_{R,y-1} + \left(PopGrowth_{IR,y} * Population_{R,y-1}\right) * TimeStep$$

Eq. 3.23

According to the survey, the household's size ranges between 2.3 and 2.9 residents (Hellenic Statistical Authority, 2012a). Projections between the base year and 2040 were estimated considering forecasts associated with the population and households (Hellenic Statistical Authority, 2012a; Eurostat, 2018). The number of households considering an annual growth (HhGrowth), assuming extrapolation of historical trends over the last decade, is illustrated in Figure 3.28 with the annual population growth projections for the three island regions.

$$Avg\ HhSize_{R,y} = \frac{Population_{R,y}}{HhNumber_{R,y}}$$

Eq. 3.24

Where:

$$HhNumber_{R,y} = HhNumber_{R,y-1} + \left(HhGrowth_{IR,y} * HhNumber_{R,y-1}\right) * TimeStep$$

Eq. 3.25

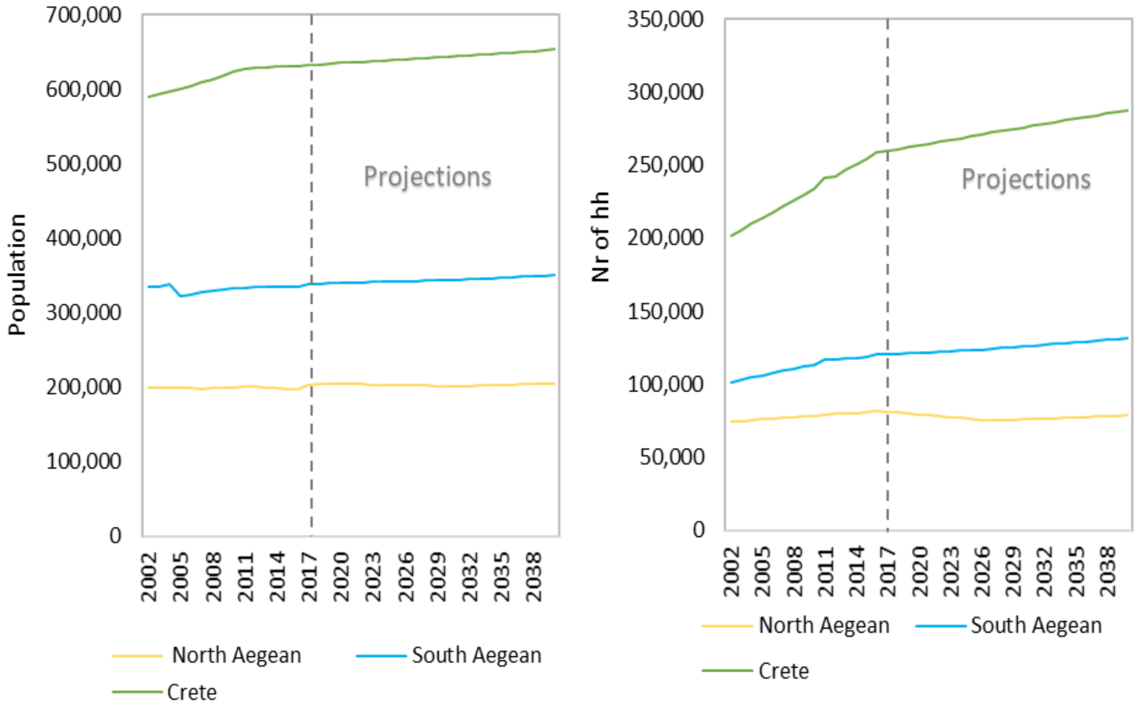


Figure 3.28: Population and hh projections per IR

Concerning GDP, the first test applied to the sample was the $R^{2,}$ with values close to 1 for all three IR. The overall significance of F is larger than the F critical value, proving the multiple regression models' significance for defining demand. Furthermore, assuming a confidence level of 95%, the t-test applied to all the independent variables showed a significant relationship between the three variables and the household residential demand. Overall, the two scenarios incorporated in the modelling exercise are diversified by the social welfare projections (GDP) following a top-down approach. In contrast, one population and household growth scenario were considered as described in the following paragraphs.

Scenario 1, the ‘Ambitious Scenario’, assumes that GDP growth at the regional level will evolve following the same pace as the rest of the country. The historical GDP figures for Greece at the national and regional level per IR derive from Eurostat (2019b, 2019c), forecasting a close correlation between the national and regional GDP growth figures from 2001-2016. The historical data show fluctuations in GDP affected by economic and political events, while forecasts predict a smooth revert towards growth following 2018. The Organisation for

Economic Cooperation and Development (OECD) (2019) annual projections proposed the national GDP growth scenario. Under the Ambitious Scenario, the OECD forecasts for Greece's increased GDP growth until 2025, ranging between 2% and 4% per annum. Following 2026 and until 2040, the growth pace slowed to 1%.

Scenario 2, the 'Average Scenario', assumes the BAU practices' continuation considering 40 years of GDP data (1977-2017) at the national level Eurostat (2019b, 2019c). The results from this approach assume that until 2025, the GDP growth will decrease as the economic recession in Greece continues, extrapolating historical data from 2007 to 2016. For 2025 and 2040, growth based on the 40-year historical data is applied. Figure 3.29 illustrates the projections under the Average and Ambitious Scenarios affecting the regional residential demand.

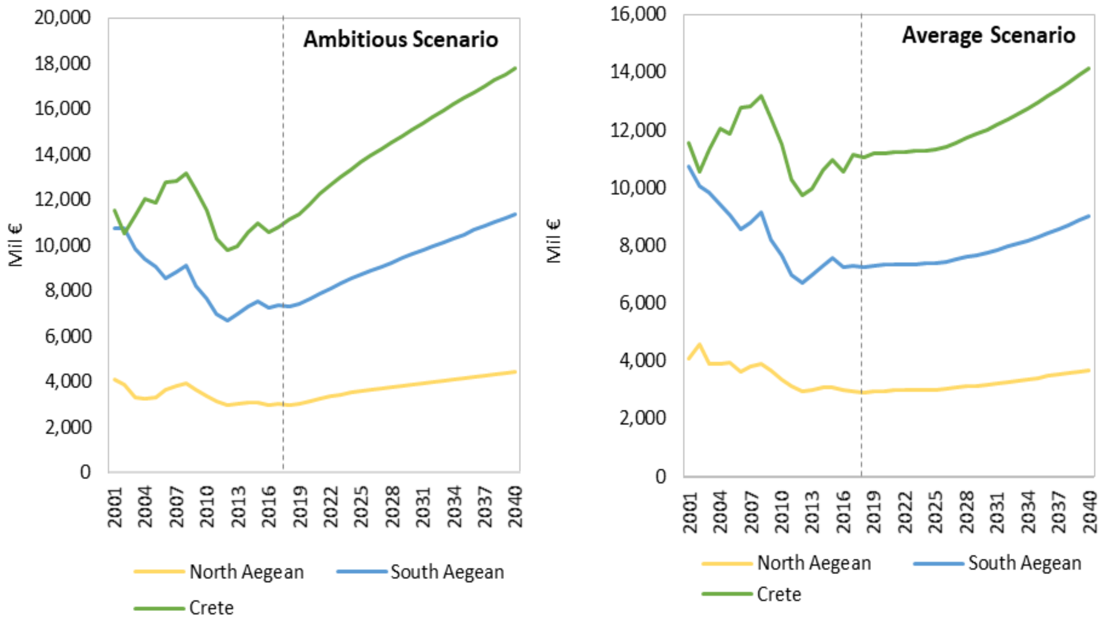


Figure 3.29: GDP regression analysis between national figures and IR

The actual demand growth projections (dgRES) for the whole projection horizon resulting from the regression analysis are illustrated in Figure 3.30. It becomes evident that following 2030, the discrepancies between the two scenarios are minimized while the island region anticipating the fastest growth in energy demand is the South Aegean. On the contrary, the Northern Aegean Sea region with the lowest growth recorded negative growth values until 2027. A relative growth onwards is limited for the following year of 2032.

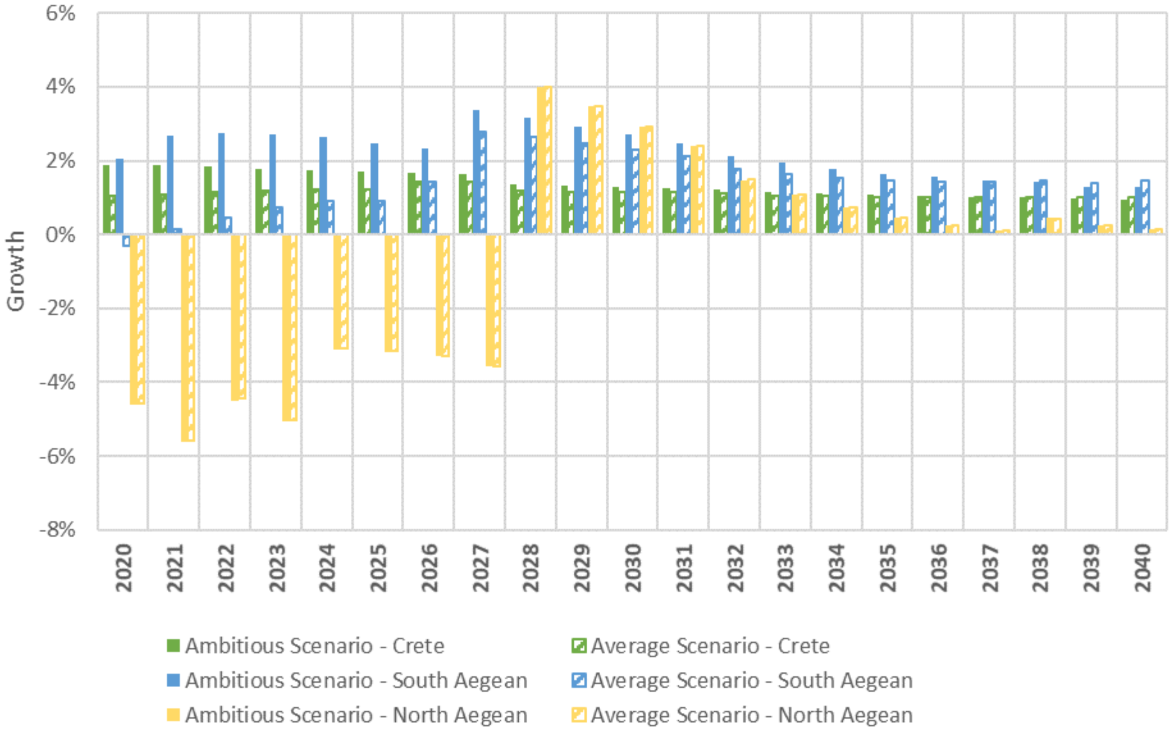


Figure 3.30: Annual demand growth (dgRES) for the Residential sector per IR

3.3.5.2 *Efficiency*

The efficiency rates of the leading residential end-uses were inserted in the model to calculate the useful energy made available in the form of electricity expressed in consumption equivalents for the work performed by space heating, cooling, water heating, cooking, and lighting and appliances (Madureira, 2014). The efficiency indicators derive from several sources: JRC (2009; Katsaprakakis *et al.* (2010); The Carbon Trust (2012); E3MLab (2016a) and vary slightly from region to region based on the energy efficiency of the reported appliances stock. The efficiency values per end-use under the residential sector in 2016 are presented in Table 3.7.

Table 3.7: 2016 Residential efficiency factors per end-use

Sub-Sector	Island Region (NUTS-2)		
	Crete	North Aegean	South Aegean
Space heating	220%	220%	211%
Space cooling	280%	227%	241%
Water heating	93%	99%	100%
Cooking	83%	87%	91%
Lighting	6%	6%	5%
Appliances	146%	158%	133%
Other uses	80%	81%	83%

In order to capture the efficiency dimension, the future efficiency indicators (esRES) were sensitised through two Efficiency Scenarios inserted in the ISLA_EGI model. Therefore, the electricity usage was divided into two energy efficiency groups: weather-dependent electrical uses (space heating, cooling, and water heating) and non-weather-dependent (cooking and other appliances). Lighting was treated separately. The methodology adopted in both scenarios aligns with the available information identified in the literature, focusing primarily on the national or when not available on the European level, assuming that the same products will be available across the EU. The efficiency growth indicators for both scenarios are presented in Table 3.8.

The **'<u>Efficient Scenario</u>'** considers the Energy Efficiency and Eco-design directive (European Commission, 2012; European Comission, 2021) as well as the technical specifications arising from the directive's implementing regulations. All energy-consuming activities are prioritised in the European Energy Efficiency Agenda. The recent revised Energy Efficiency Directive (European Commission, 2018b) is a significant policy driver, imposing annual savings of 0.8% of the final energy demand by 2030, also reflected in the electricity sector. Even though electricity demand accounts only for 20% of Greece's total energy, while residential electricity demand could be pinned down to approximately 5%, the building sector is one of the critical carbon emitters.

In this sense, it was discovered that heating and cooling appliance efficiency could improve, as there is a big market for innovative technologies such as electric heat pumps and micro-combined heat and power systems on the Greek islands. This is evident in the out-of-date stock of heating and water heating devices that do not meet labelling regulations and have a replacement time of 2040 and beyond. Similarly, cooling equipment is typically comprised of obsolete HVAC units that do not meet labelling requirements. As described in Sections 3.3.2.2 and 3.3.2.3, a technology-specific factor was considered here for cooling and water heating. According to the Eco-design directive and energy labelling standards, almost the entire appliances fleet could improve efficiency. Nevertheless, projections were denoted in a rather empirical approach for many appliances such as ICT (Internet & Communication Technologies). Overall, it is assumed that electrical appliances will have continuous growth in energy efficiency with no remarkable breakthroughs than the heating and cooling sector, which are marginally slowing down following 2030.

The ‘**Reference Scenario’** adopts the hypothesis that the efficiency of newly manufactured appliances reaches -all but limited to the minimum- Eco-design standards by 2020. All power technologies evolve in time and become more efficient without any significant discoveries in technological development or any major human behavioural shift towards energy efficiency. Consumers will select technologies that have been tested and validated, aligning with the EC Energy Efficiency Scenario (European Commission, 2016b). A technology-specific factor for cooling is linked to this scenario. As an outcome, Greece to successfully meet the requirement of reducing its energy savings by 38% by 2030, should employ measures that could offset emissions from other harder-to-decarbonise sectors such as transport and industry. Nevertheless, following 2030, the Reference Scenario is inevitably picking up a global shift towards energy efficiency equipment.

Table 3.8: Residential energy efficiency growth (esRES) indicators

End-uses Groups	Efficient Scenario		Reference Scenario	
	2020-2029	***2030-2040***	***2020-2029***	***2030-2040***
Heating & Cooling	0.64%	0.7%	0.34%	0.4%
Electronic appliances	0.14%	0.12%	0.07%	0.1%
Lighting	0.6%	0.8%	0.4%	0.6%

Furthermore, the building envelope properties defined in the two surveys provide a basis for applying renovation rates that are input in the model, based on their age, usually directly relevant to the materials and insulation type installed. The number of rooms and the size of the houses is used to calculate relevant energy uses such as heating and cooling.

All the households interviewed use their properties as permanent residences, with 97% living there all year round. The ownership rate of residential houses is as high as 80% (Hellenic Statistical Authority, 2013, 2016a), providing a satisfactory basis for future energy efficiency interventions related to the building envelope. Almost half of the survey participants live in detached houses, usually increasing the household's energy needs. The average number of regular rooms on the Greek NIIs is three. The average total surface of the dwelling is 84 m^2, balanced among the three regions and the national figures. More than half of the population is living in non-insulated buildings, including buildings built before 1981, resulting in a great amount of energy to ensure the currently accepted standards of comfort in the winter (Hellenic Republic - Ministry of the Environment and Energy, 2010a; Aravantinos *et al.*, 2017).

The most widespread glazing solution is the simple single glazing. The share of responders using double plus glazing is 39%, reduced compared to the national level at 49% linked to the hh income. By 2016, the share had increased to

46%. Window systems are principally aluminium and wooden, typical for the local traditional architecture, especially in the South Aegean Islands.

The breakdown of the age of residential houses in 2012 is presented in Table 3.9. According to the census data, 63% of the Greek islands' residential houses were built before 1980. As the average period before proceeding to a renovation at the residential level is usually 35 years (Hellenic Republic - Ministry of the Environment and Energy, 2018c), 76% could already benefit from a renovation in 2020. Considering the 2030 milestone, we expect most buildings to need a medium to deep renovation by then. The 2016 survey results show that due to the economic austerity, low construction activity is recorded following 2016. During that time in Greece, several instruments were put in place, such as the 'Residential Savings Programme' (Hellenic Republic - Ministry of the Environment and Energy, 2020c), which led to renovating 9% of the building stock exceeding the average renovation rates of previous years (Esser *et al.*, 2019).

Due to the proximity of the Greek islands' residential buildings' age with the national ones, the same renovation rates can be applied. Two scenarios were considered: the Average Scenario and the Ambitious Scenario as identified in the Hellenic Republic - Ministry of the Environment and Energy (2015), assuming different renovation rates and energy savings as indicated in Table 3.10. The assumptions supposing different renovation rates occur at different energy savings levels ranging between 20% and 80%. Overall, Eq. 3.26 calculates the average annual savings. This parameter was inserted in the ISLA_EGI model as an additional input compared to the model's original set-up.

Table 3.9: Timeframes of national rates of buildings erection

Timeframe	North Aegean	South Aegean	Crete
Before 1919	19.500	8.504	13.665
1919 - 1945	34.297	13.970	27.002
1946 - 1960	25.747	12.754	34.770
1961 - 1970	18.687	10.828	27.281

1971 - 1980	17.210	13.966	27.398
1981 - 1985	11.068	9.247	16.924
1986 - 1990	8.384	8.504	15.168
1991 - 1995	7.033	7.588	12.783
1996 - 2000	6.461	7.771	13.984
2001 - 2005	6.228	7.893	14.365
Later than 2006	5.596	6.648	12.192
Under Construction	2.123	2.776	2.745

Table 3.10: Assumptions for calculating the average annual savings in the residential sector

Period	**2020-2029**			**2030-2040**		
Scenario	**Annual Savings (AS)**	**[(%) of the refurbished building stock (RBS) *(%) energy savings per building (ES)]**	**Average Annual Renovation Rate (AR)**	**Annual Savings (AS)**	**[(%) of the refurbished building stock (RBS) * (%) energy savings per building (ES)]**	**Average Annual Renovation Rate (AR)**
Average	0.38%	(70%*20%+25% *40%+5%*60%)	1.40%	0.95%	(40%*20%+40% *50%+10%*60%)	2.8%
Ambitious	1.05%	(60%*60%+40% *30%+20%*10%)	2.10%	1.45%	(20%*5%+25%*40% +65%*60%+ 5%*80%)	2.7%

AS is calculated as:

$$AS = AR \ * \sum_{i}^{TC}(RBS * ES_{TC})$$

Eq. 3.26

Where:

'AR' is the annual renovation rate;

'RBS' is the percentage (%) of the refurbished building stock;

'ES' are the energy savings;

TC' is the total number of categories for energy savings.

3.4 Services sector

3.4.1 Reference demand profiles

The services sector is split into the Commercial and Tourism sub-sectors. The commercial sector includes: commercial centres, shops, entertainment venues, catering, education, health centres and offices also, private practises, clinics, and private education centres. Because of its importance to the Greek islands' economy and its impact on electricity usage, tourism has been treated separately. The Tourism sector accounts for about half of all power demand in the services sector, with hotels and other lodging structures accounting for most.

The total electricity consumption per electrical use was calculated for each autonomous electrical region (R) for the commercial and tourism sectors, according to Eq. 3.27 and per sector according to Eq. 3.28, considering: I) the total building stock per island, II) the share of electrical uses performed at NUTS-3 level[25] - considering IRs as prefectures, III) a relevant age dependant weight factor for buildings, IV) the size (m^2) per type of building, and V) the average annual electricity use per m^2 as extracted from the EPCs. The data collection and processing are described in the following paragraphs.

[25] NUTS 3: small regions for specific diagnoses

$$Total\ El.Consumption_{S,R,u} = \sum_{b}^{B}\sum_{a}^{A} (BT_{b,a,R} * Wf_a * Sf_{b,IR}) * AaC_{b,U,IR}$$

Eq. 3.27

$$Total\ El.Consumption_{S,R} = \sum_{u}^{U} Total\ El.Consumption_{S,R,u}$$

Eq. 3.28

Where:

'S' is sector (Commercial or Tourism);

'b' is the building type, b=1…B;

'U' is the electricity uses, u=1…U;

'a' is the age group, a=1…A;

'R' is the independent transmission region;

'$BT_{b,a}$' is the total number of buildings per building type per age group and R;

'Wf_a' is the weight factor per age group;

'$Sf_{b,IR}$' is the average square meters per building type per IR;

'$AaC_{b,U,IR}$' is the annual average electricity consumption per building type, use and IR.

The total number of buildings per type, age and AES (R) is provided by the Hellenic Statistical Authority (2012). Between 2000 and 2005, the construction sector flourished in Greece (Hellenic Republic - Ministry of the Environment and Energy, 2017d). However, during 2006-2011 there was a decline equal to 20% per year, preceded by the economic crisis. Following 2012, the construction sector is continuing its shrinkage. In order to address the time lag between 2012 and 2016, statistics related to the country's construction development were considered equal to +1.3% per year (Hellenic Statistical Authority, 2019b).

Weight factors were calculated from the national building stock registry in relation to their energy performance and assigned to buildings according to their age to allow a realistic extrapolation of their electricity consumption (Table 3.11). The same table indicates the electricity consumption per age group and 'Energy Performance Class', highlighting the relationship between age and energy consumption. The Hellenic Republic - Ministry of Environment and Energy (2008) provides the energy performance class categorisation. It is evident from the statistics that buildings belonging to classes A and B representing 3% of the building stock are responsible for less than 2% of the total building consumption. In comparison, more than 33.6% of Greece's electricity consumption in buildings is attributable to the lowest category 'G', including buildings built between 1960 and 1980, with average consumption equal to approximately 270 kWh/m^2. The results imply the urgency for the commercial building stock's refurbishment to achieve the energy efficiency improvement targets of 38% by 2030.

Table 3.11: Electricity Consumption per age group and energy class ranking (Hellenic Statistical Authority, 2012a; Hellenic Republic - Ministry of the Environment and Energy, 2016a, 2017b, 2018a)

Energy Class	**2010-2016**	**2000-2009**	**1990-1999**	**1980-1989**	**1970-1979**	**1960-1969**	**< 1959**	**Share – Energy Class**
A+	9,490	3,315	585	195	520	390	0	**0.002 %**
A	23,855	30,030	6,230	5,460	2,590	2,800	0	**0.012 %**
B+	275,145	313,073	80,438	72,930	58,403	40,170	1,170	**0.137 %**
B	1,200,550	4,309,240	1,203,020	790,140	544,180	368,550	19,110	**1.375 %**
C	1,115,790	30,617,615	13,860,255	9,551,875	6,472,645	4,802,210	235,135	**10.868 %**
D	490,750	33,864,425	23,666,125	19,149,375	17,286,500	12,661,775	680,750	**17.576 %**
E	126,035	24,636,490	24,441,330	21,098,805	27,658,395	18,958,810	866,740	**19.204 %**
F	35,620	3,894,030	5,943,210	15,014,335	45,379,880	33,197,990	1,871,555	**17.174 %**
G	31,525	1,734,210	5,656,770	23,430,330	85,901,310	84,876,660	4,761,720	**33.651 %**

Share – Age Group	**4.82%**	**12.93%**	**13.91%**	**15.42%**	**17.36%**	**17.71%**	**17.85%**	**100%**
Weight Factor (Wf_a)	**30.92%**	**82.89%**	**89.17%**	**98.81%**	**111.25%**	**113.53%**	**114.42%**	

In the Commercial sector, all buildings types fall except for accommodation, which is included in Tourism. The average surface per building type under the divisions indicated in Table 3.12 was provided by the Hellenic Republic - Ministry of the Environment and Energy (2017c). In particular, hotels and other types of accommodation were estimated based on the business registry (Hellenic Touristic Organisation, 2018).

Table 3.12: Average surface per building type per IR ($Sf_{b,R}$)

IR (NUTS-2)	Shops	Health	Hotels/ Accommodation	Education	Entertainment / Catering	Offices
(m^2)						
North Aegean	108	158	311	534	228	3,078
South Aegean (Cyclades)	99	176	408	397	115	2,068
South Aegean (Dodecanese)	121	456	477	441	211	3,828
Crete	140	746	504	809	364	2,501

The Services sector's average electricity consumption originated from the National Repository of Energy Performance Certificates (EPCs). The data are provided at the NUTS-3 spatial resolution level, including statistics from 2015, 2016 and 2017. In contrast with the scenarios for residential demand, we were able to retrieve data for the Cycladic and Dodecanese regions individually. The EPCs estimate the total average per m^2 energy consumption for space heating, cooling, water heating, lighting, and other purposes following a building inspection and measurement analysis while considering the building envelope and all the electromechanical installations. In order to extract the electricity consumption per energy use, aggregated statistics were manipulated and published by the Hellenic Republic - Ministry of the Environment and Energy, (2016a, 2018a); Hellenic Republic - Ministry of Environment Energy and Climate Change (2017). The average electricity consumption per building type, end-use and IR ($AaC_{b,U,IR}$) was calculated as displayed in Figure 3.31. The data representing average values deriving from the three-year EPC statistics demonstrate the importance of electricity uses for the Services Sector.

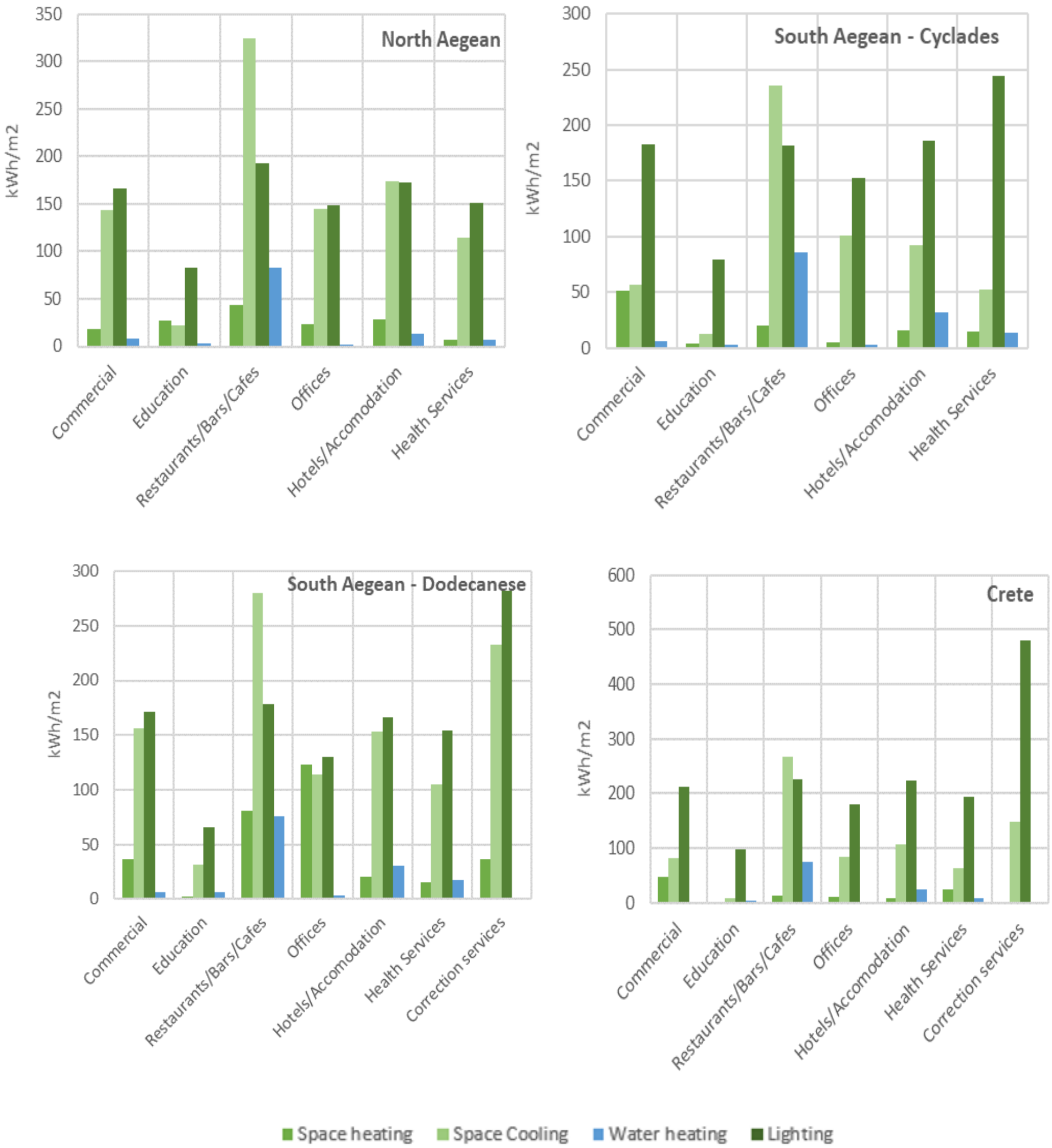


Figure 3.31: Average annual consumption per use and IR in the Services sector ($AaC_{b,U,IR}$)

3.4.2 Demand breakdown

The electricity demand breakdown per use and island region (IR) in the commercial and tourism sectors is depicted in Figure 3.32 and Figure 3.33. The electricity demand share is inserted in the ISLA_EGI model as an input for the base year (2016). Regarding commercial activities, the critical power consumer is the lighting sector, with shares ranging between 29% and 45%, followed by space cooling, ranging between 26% and 37%. Water heating has a small share as the quantities of heated water is limited. The usage of HVAC to heat large expanses in professional buildings continues to have a small share of total power demand, less than 8%, but it is more frequent than in the residential sector. The proportions in the tourism sector remain stable; nevertheless, as expected, water heating demand increases compared to the commercial sector, as residents use water for showering and other purposes in addition to catering and laundering. In the Dodecanese region, space cooling outnumbers other uses, accounting for about half of the final electricity demand, indicating a substantial margin for replacing ageing HVAC systems paired with efficient practises and expenditures in refurbishment.

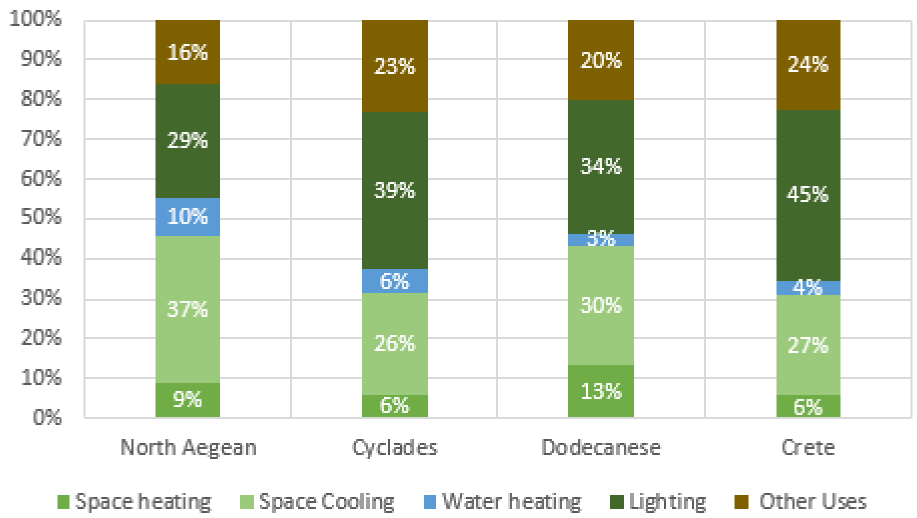


Figure 3.32: Commercial electricity demand share per IR

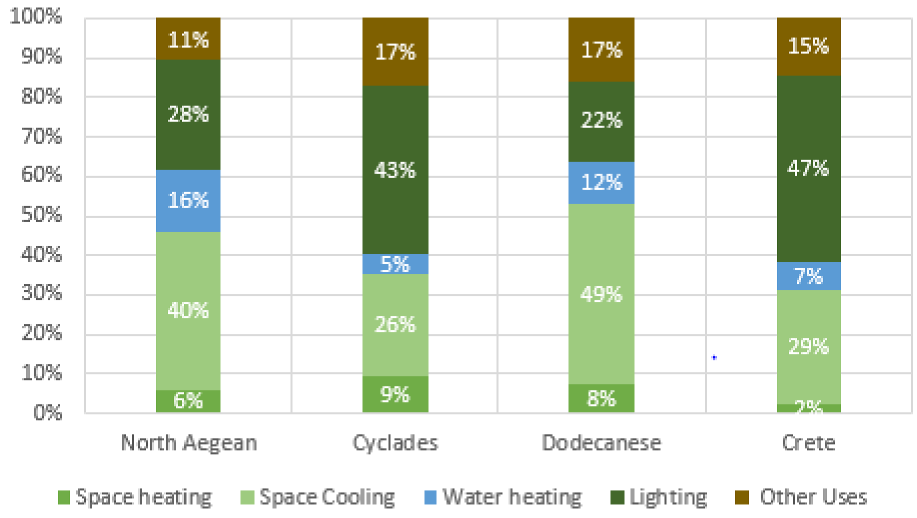


Figure 3.33: Tourism electricity demand share per IR

3.4.3 Demand scenarios

3.4.3.1 *Socio-economic driven*

The services sector accounted for more than 44% of the total electricity generation in 2016 (Benaki, 2019; Hellenic Statistical Authority, 2019a), while historical data show a tendency for growth over the years. Tourism accounts for 17% of the country's GDP, with ongoing increasing trends (Statista, 2021). In 2018, more than 17.8 million tourists arrived in Greece from abroad (Hellenic Statistical Authority, 2019c), without counting internal tourism (5.8 million trips) (OECD, 2018), out of those 8.7 million tourists visited the Greek islands. Figure 3.34 shows the increasing tourism trends on the Greek NIIs between 2002 and 2015, mainly in Crete and South Aegean Regions. Following 2015 and until 2018, according to the latest available published statistics per region, there was an unprecedented increase which exceeded 25% on average[26].

[26] Impacts due to COVID-19 have been excluded from this analysis

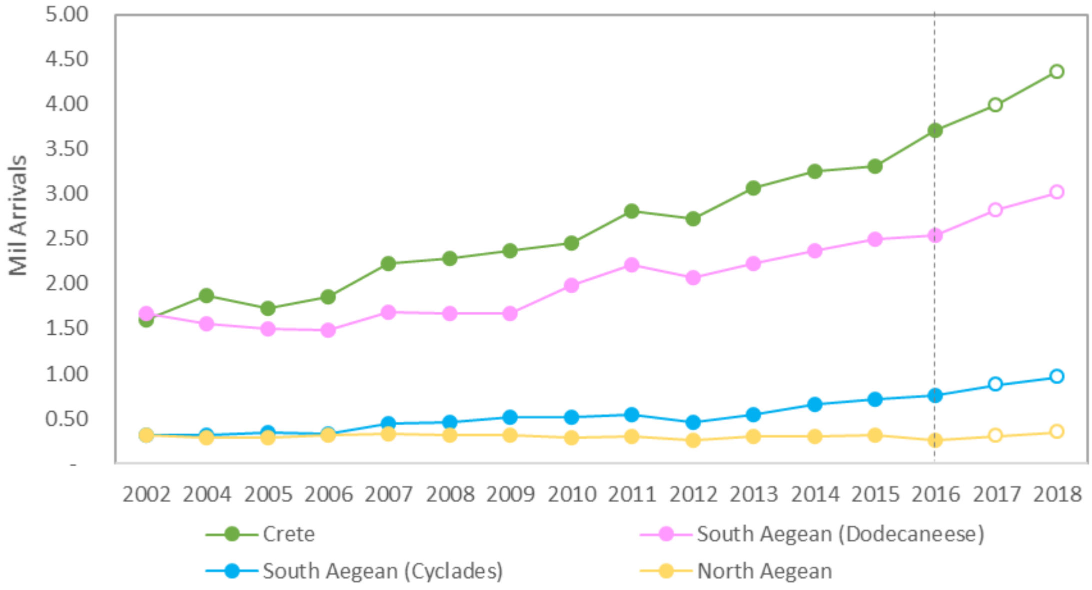


Figure 3.34: International tourists arrivals on the NIIs (Benaki, 2019; Hellenic Statistical Authority, 2019a)

While no correlation was identified between the local GDP growth and the touristic demand growth, a strong correlation between the tourists' arrivals (x) and the electricity consumption (y) was evidenced, taking into account available statistics from 2002 until 2016. The tourism sector's electricity demand growth (dgTOUR) derives from the applied regression analysis considering one socio-economic dependent scenario called the 'Ambitious Scenario', directly linked with the Tourism Arrivals for each region between 2020 and 2040 presented in Table 3.13. The intercept was set equal to zero, assuming that if tourists' arrivals are equal to zero for one year, the touristic demand related to the accommodation will likewise be zero.

Table 3.13: Annual demand growth (dgTOUR) for the Tourism sector per IR

IR **(NUTS-3)**	**Annual Projections** **2020-2040**
Crete	4,07%
South Aegean (Dodecanese)	2,16%
South Aegean (Cyclades)	3,18%
North Aegean	1,03%

The commercial sector's demand will rely on the Greek Government's energy projections in the latest published NECP approved by the European Commission (Hellenic Republic - Ministry of the Environment and Energy, 2019b). The national figures were amplified considering a weight factor relevant to the touristic demand growth, which prevails any region's domestic economic fall. According to the Hellenic Statistical Authority (2016a), 33% of the Commercial Sector demand is affected by touristic activities in the North Aegean Region, 56% in the Dodecanese, and 44% in the Cyclades and 43% in Crete. Therefore, in addition to the national demand projection figures (dgNATIONAL), the tourism impact on the commercial sector in the islands region (Ti_{IR}) is translated into a weight factor utilised according to Eq. 3.29. The commercial demand growth (gdCOM) between 2020 and 2040 is illustrated in Figure 3.35.

$$dgCOM_{y,IR} = dgNATIONAL_{y} + Ti_{IR} * dgTOUR_{y,IR}$$

Eq. 3.29

3.4.3.2 *Efficiency*

Energy efficiency factors across the services sector per end-use are presented in Table 3.14, assuming the same developments will occur across all islands. Two efficiency scenarios have been considered here, aligned with the residential sector, the **Efficient** following the respective directives and the **Reference**, configured based on literature. The reference values were extracted from multiple resources (National Technical University of Athens, 2008; Hellenic Republic - Ministry of the Environment and Energy, 2017e, 2019a), which provided the baseline to assume more aggressive energy efficiency pathways. The developments are applied across all fields similar to the residential sector but further enhanced, assuming that more investments are likely to occur here, as indicated in Table 3.15. It was deemed that both the commercial and tourism sectors are significantly affected by imported tourism with a larger margin for energy efficiency improvements.

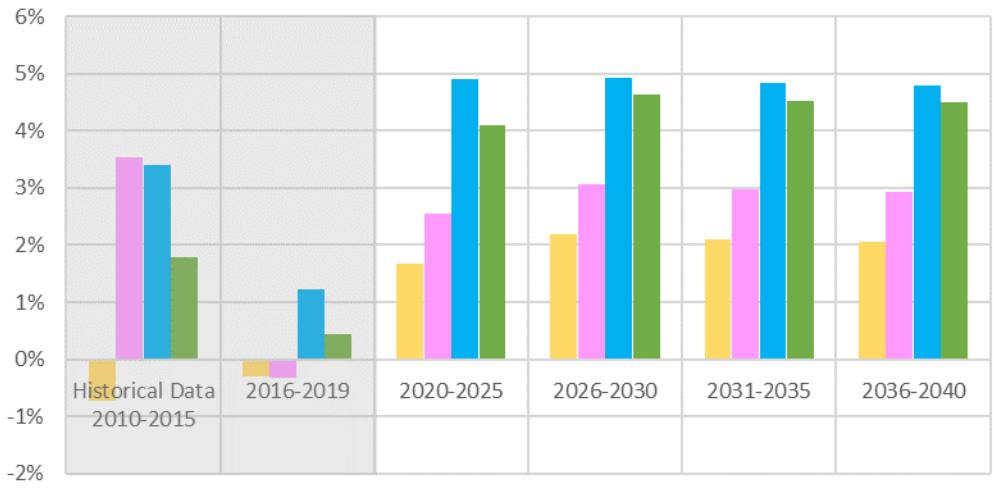


Figure 3.35: Annual demand growth (dgCOM) for the Commercial sector per IR

Table 3.14: 2016 Services energy efficiency factors per sub-sector

Sub-Sector	Efficiency
Space heating	220%
Space cooling	280%
Water heating	93%
Lighting	6%
Other Uses	82%

Table 3.15: Services energy efficiency growth (esSER) indicators

Groups	Efficient Scenario		Reference Scenario	
	2020-2030	***2030-2040***	***2020-2030***	***2030-2040***
Heating & Water Heating	0.90%	0.90%	0.34%	0.29%
Cooling	0.90%	1.22%	0.34%	0.29%
Lighting	0.80%	0.60%	0.60%	0.40%
Others	0.25%	0.70%	0.20%	0.12%

The same renovation rates (AR) were incorporated as specified in the 'Residential Scenario'. Nevertheless, in the 'Ambitious Renovation Scenario', the average energy savings following 2030 are assumed to increase to 2.1% compared to the equivalent in the residential sector of 1.45% aligned with the Hellenic Republic - Ministry of the Environment and Energy (2018d).

3.5 Other sectors

Other demand sectors were introduced in the original ISLA model: the **Public Sector**, which includes public administration and other public buildings, including schools and hospitals and street lighting, the **Agriculture and Industry** Sectors. In the ISLA_EGI version, they were treated with simplicity because no available data for the end-uses became available as they do not represent more than 10% of the total electricity demand on the islands. Consequently, no breakdown in end-uses is included while their trajectories are not diversified, considering one scenario for each sector.

Demand growth in the public sector comprising governmental buildings and decentralised authorities and street lighting derived from the Hellenic Republic - Ministry of the Environment and Energy (2017c, 2019b), since the national figures have aligned with the ones recorded on the Greek islands. An annual renovation rate of 3% was considered according to 2012/27/EU (European Union, 2012b), with two different energy-saving approaches adopted through the '**Average**' and the '**Ambitious**' Scenarios (Hellenic Republic - Ministry of the Environment and Energy, 2015, 2017d). The complete set of assumptions is included in Table 3.16.

Table 3.16: Assumptions for calculating the average annual savings in the public sector

Period	**2020-2030**			**2031-2040**		
Scenario	**Annual Savings**	**[(%) of the refurbished**	**Average Annual Renovation**	**Average Annual Savings**	**[(%) of the refurbished**	**Annual Renovation Rate (AR)**

		building stock (RBS)* (%) energy savings per buildings (ES)]	**Rate (AR)**		**building stock (RBS) * (%) energy savings per buildings (ES)]**	
Average Scenario	1.32%	3%*(40%*80%+20%*60%)	3%	1.82%	3.5%*(40%*40%+60%*60%)	3.5%
Ambitious Scenario	1.44%	3%*(40%*60%+40%*60%)	3%	2.40%	4%*(40%*20%+60%*60%+20%*80%)	4%

With respect to the agricultural demand, double shares (8%) are scored compared to the national demand figures for islands such as Crete. Historical trends showed that Crete increased its demand by 7% between 2006 and 2016 compared to 2.5% nationally. In the South Aegean region, agricultural demand was reduced by 15%, while in the Northern Aegean Sea region, despite annual fluctuations, it remained almost at similar levels (Hellenic Statistical Authority, 2016a). Regression analysis was applied for all three regions, considering projections at the national level as presented in the NECP (Hellenic Republic - Ministry of the Environment and Energy, 2019a). The results with a five-year time step are depicted in Figure 3.36. Industrial activities are limited in the islands region (between 4% and 5.5% for North and South Aegean Sea islands and 8.5% for Crete), considering 10-year historical data (Hellenic Statistical Authority, 2012b, 2016a). This sector's electricity demand growth indicators followed the moderate national projections as illustrated below.

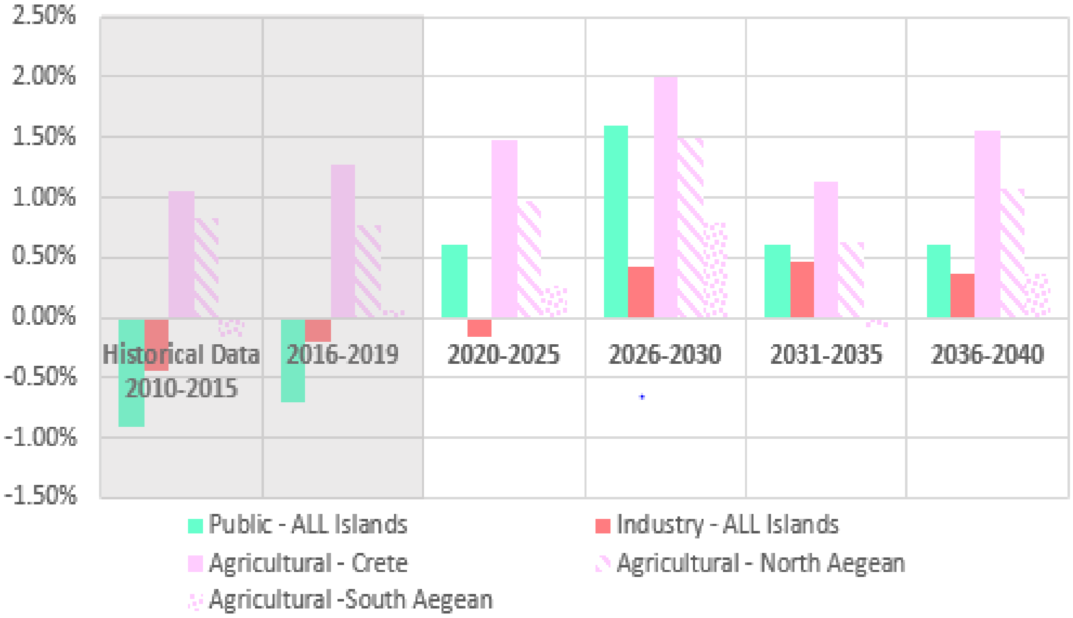


Figure 3.36: Annual demand growth per sector (other sectors)

3.6 Demand profiles results

The results were centralised under two main storylines illustrated in Figure 3.37. The **Low-Efficiency Demand Scenario (Low_Eff)** proposes moderate projections for efficiency improvement and medium renovation growths. The **High-Efficiency Demand Scenario (High_Eff)** with aggressive renovation rates is also driven by relevant economic growth. Agricultural and industry demand projections remain the same between the two scenarios.

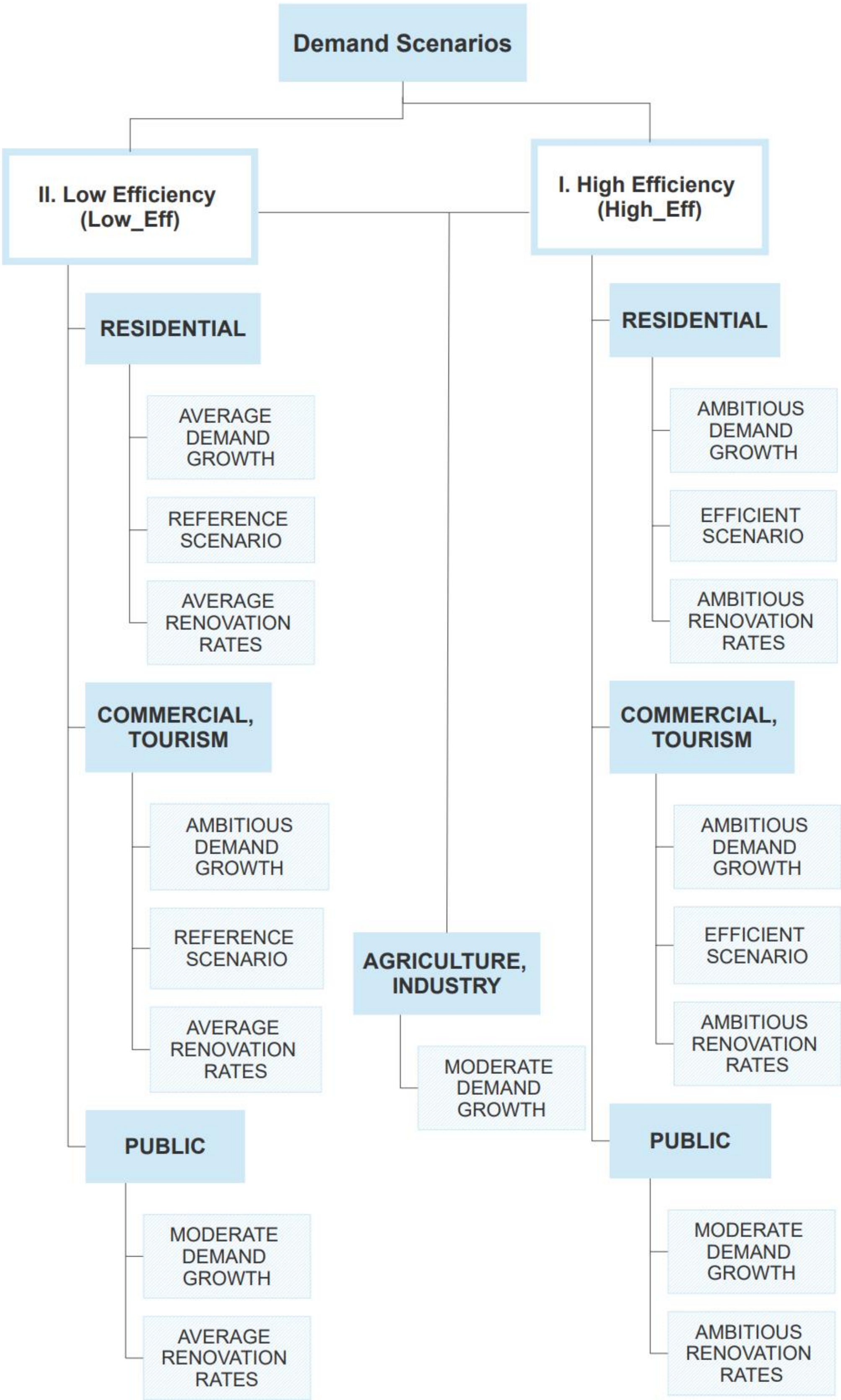


Figure 3.37: Principal demand scenarios structure

The results for each electrical island system for the Low_Eff and High_Eff scenarios are illustrated in Figure 3.38 to Figure 3.56, underling the impact of the assumptions envisaged under these two scenarios for the islands’ future demand growth. These annual demand profiles were aggregated in the supply-side modelling via the PLEXOS energy systems model. End-uses breakdown per sector are included in ANNEX I.a for residential demand, ANNEX I.b for commercial demand and ANNEX I.c for tourism.

The results show that the Greek islands' electricity demand depends principally on the residential, commercial, and tourism sectors. Small fluctuations are encountered in the residential sector in all regions except the North Aegean. The tourism electricity demand affects the entire services sector, whereas 70% of the tourists arrive between June and August, creating severely high peaks, and threatening the local system. As a result, any advancements in energy efficiency have a vast impact on the commercial and tourism sectors. The commercial sector has increased more rapidly than the tourism industry in recent years, which is expected given stronger socioeconomic demand growth indicators, as well as the expectation of increased energy efficiency investments in the Greek islands' accommodation facilities. The results prove that the efficiency measures of the tourism sector are sufficient to rationalise demand for accommodation; however, the need for a higher impact on the commercial sector is imperative. Agricultural requirements for electricity are evident only on Crete and specific Northern Aegean islands such as Lesvos and Chios, while on the rest of the islands, such activities are limited to the minimum. Similarly, industry-related electricity demand mainly exists on Crete and the Cycladic islands.

In the Low_Eff scenario, lower efficiencies are observed between 1% and 4% by comparing the ‘energy consumed versus the energy supplied’ against the High_Eff case. In this scenario, tourism and especially the commercial sector grow faster across all islands due to the low renovation rates and reduced progress in applying high-efficiency measures. The catalytic contributor to increasing electricity demand is lighting and space cooling in the tourism and commercial sectors, which are forecasted to grow higher under the Low_Eff Scenario. Such discrepancies are somehow limited in the residential sector. Considering the High_Eff scenario, the residential demand remains stable due to replacing inefficient lamps for lighting and increasing renewable energy share in water heating coupled with deep renovation rates across most islands. As mentioned earlier, the broader impact of energy efficiency measures and deep renovations is recorded in the services sector. COVID-19 implications related to demand are not foreseen herein; nevertheless, they are not anticipated to affect the projection horizon following 2022.

At the geographical level, on the Northern Aegean Sea islands and particularly the island of Lesvos, there is a general tendency to reduce the demand loads until 2030, highlighting the clear trajectory impacted by socio-economic factors such as an impoverished economy, assuming a forecasted population decrease, GDP stagnation and increased immigration as well as relatively low arrivals of tourists. Demand growth is rebounded following 2030, mainly due to improvements in the local economy and a shift towards higher tourism levels. In 2030, there is a 12-14% difference between the two scenarios, which escalated to 20% by 2040 as the impact of energy efficiency policies becomes prevalent.

In the Dodecanese islands in the South Aegean region, there is a smaller differentiation in 2030 between the two scenarios, limited to 8-9%, while by 2040, the gap extends to 28% as demand in the services sector increases and consequently, the margin for energy efficiency improves, especially in the tourism sector. In the Cycladic group of islands, the divergence reaches 12% in 2030. In 2040, it further increases to 30% due to the forecasted high tourism demand growth, creating energy savings opportunities in the future High_Eff Scenario. On the island of Crete, a 12% reduction in energy demand is recorded by 2030 between the High_Eff and Low_Eff scenario, which further increases to 20% in 2040, necessitating immediate actions toward climate change. Overall, a difference of 12% in 2030 and 26% in 2040 in demand levels is observed between the High and Low_Eff scenarios. This is translated into a 22% efficiency improvement by 2030 and 35% by 2040 against the national demand projections from 2007 as published by the European Commission (2021a).

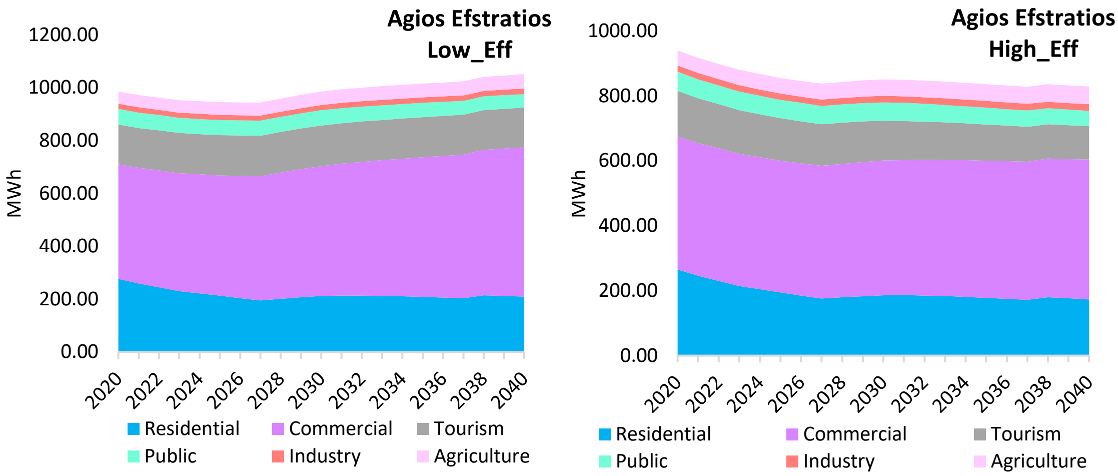


Figure 3.38: Low_Eff and High_Eff scenario results for Agios Efstratios

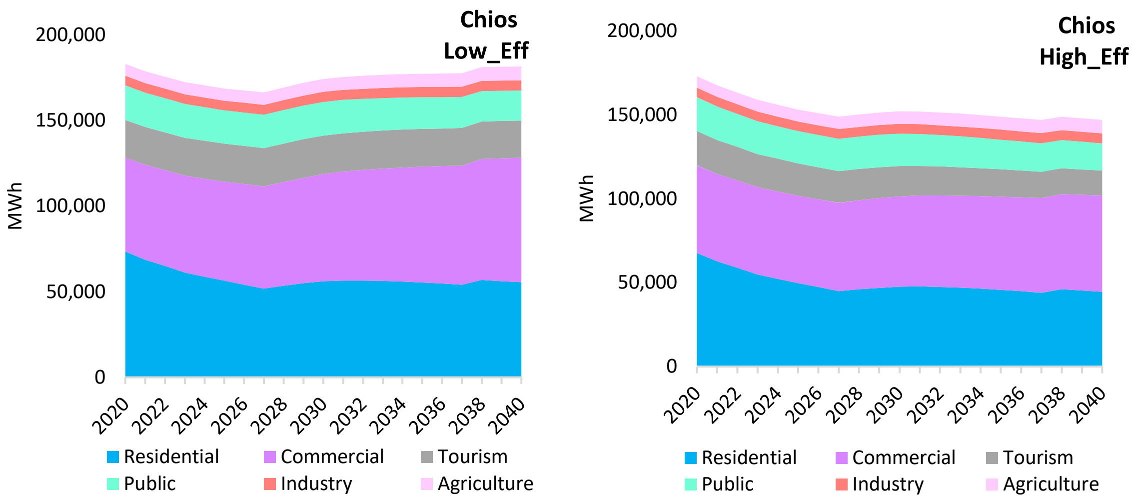


Figure 3.39: Low_Eff and High_Eff scenario results for Chios

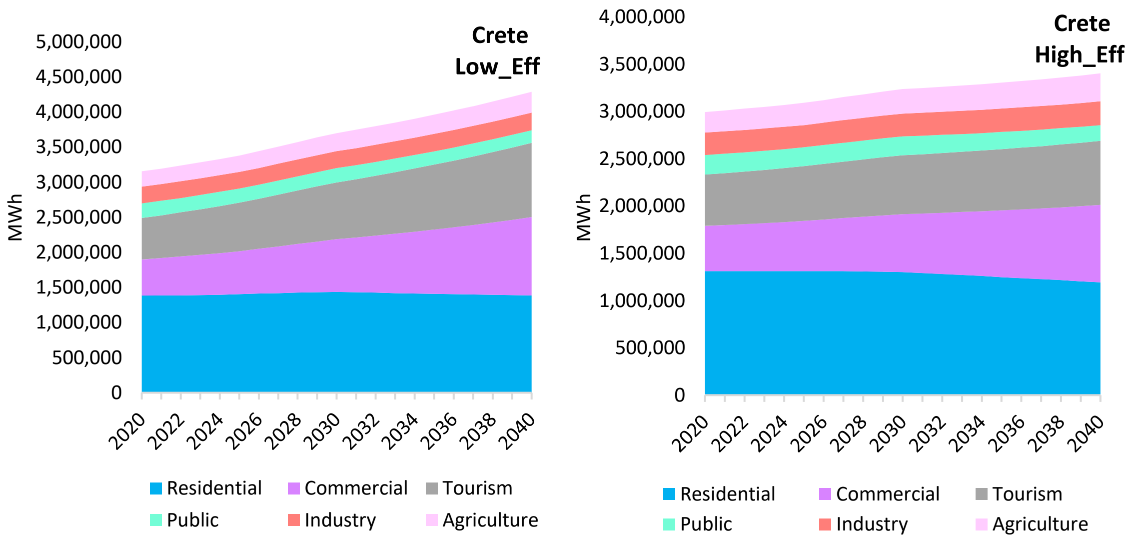


Figure 3.40: Low_Eff and High_Eff scenario results for Crete

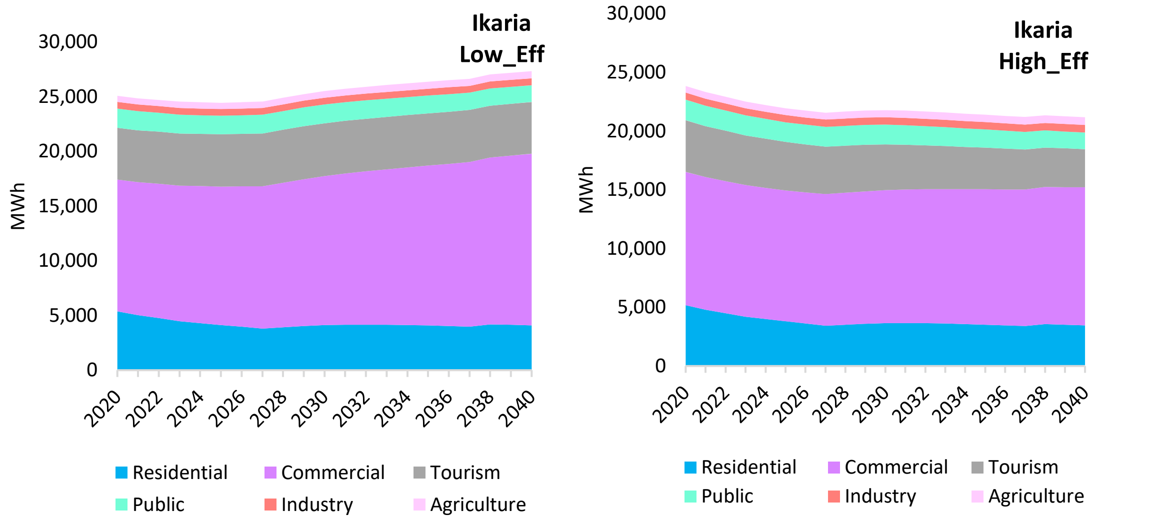


Figure 3.41: Low_Eff and High_Eff scenario results for Ikaria

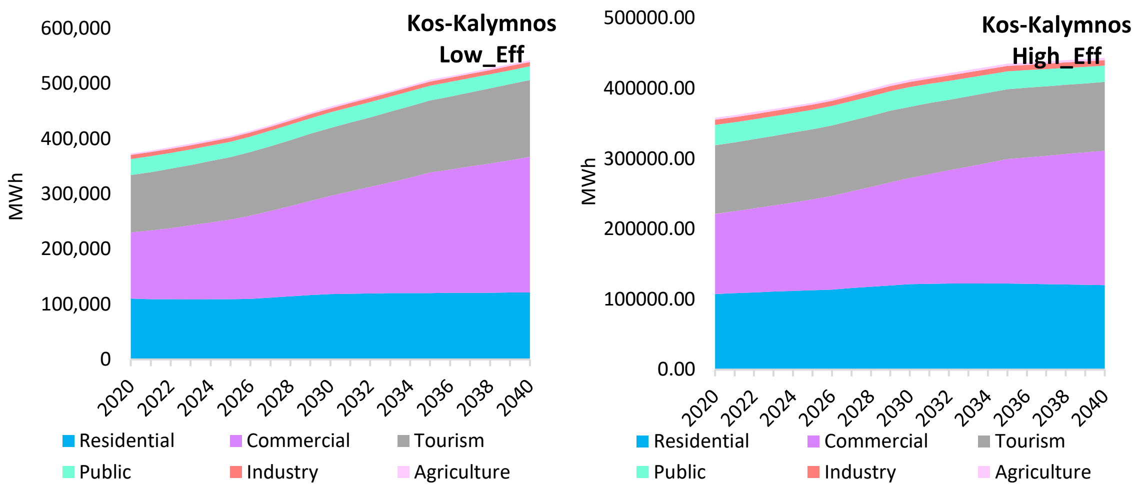


Figure 3.42: Low_Eff and High_Eff scenario results for Kos-Kalymnos

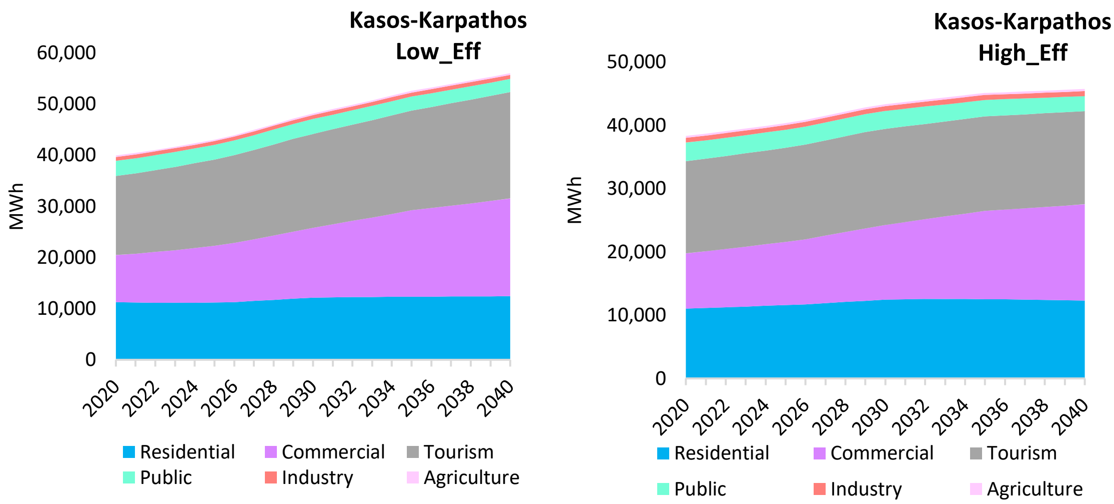


Figure 3.43: Low_Eff and High_Eff scenario results for Kasos-Karpathos

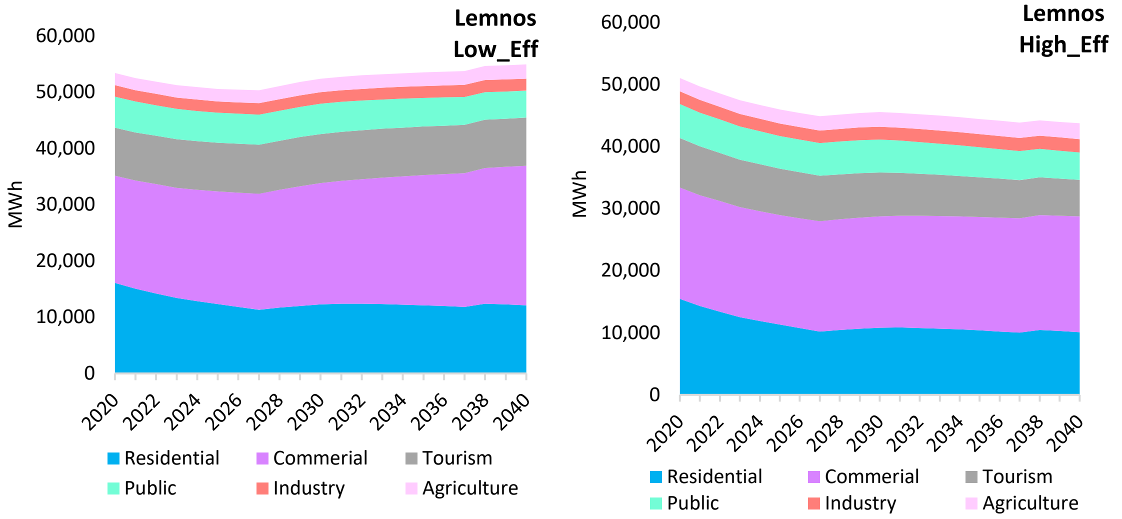


Figure 3.44: Low_Eff and High_Eff scenario results for Lemnos

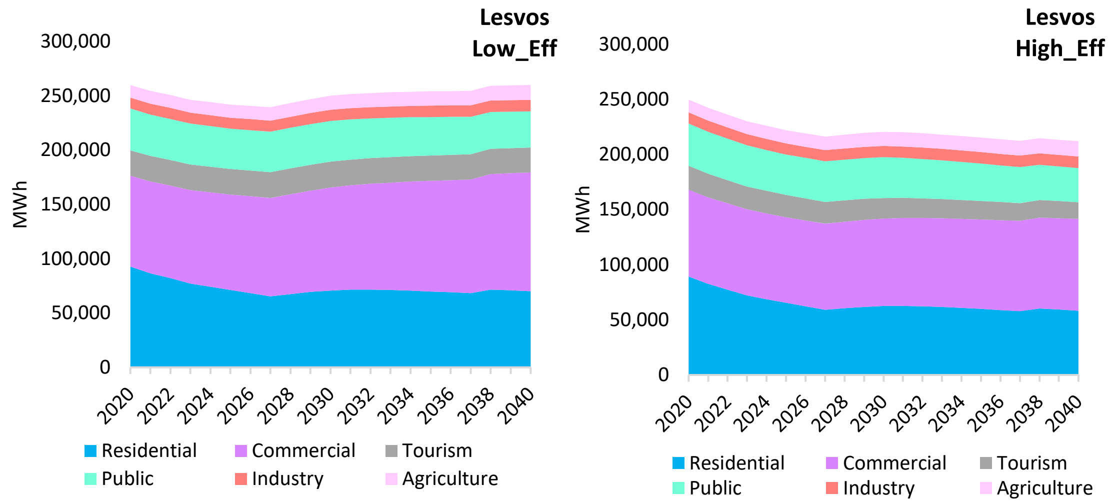


Figure 3.45: Low_Eff and High_Eff scenario results for Lesvos

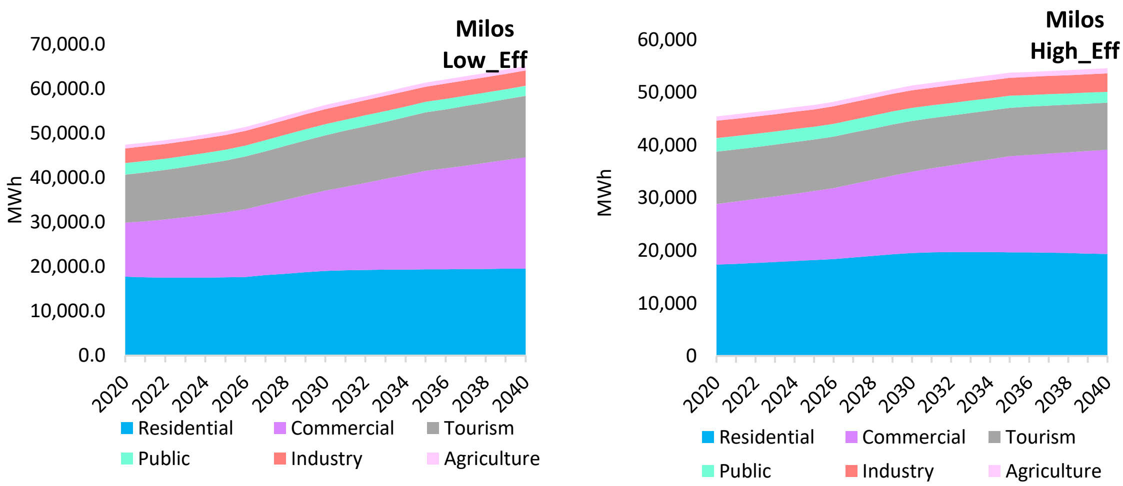


Figure 3.46: Low_Eff and High_Eff scenario results for Milos

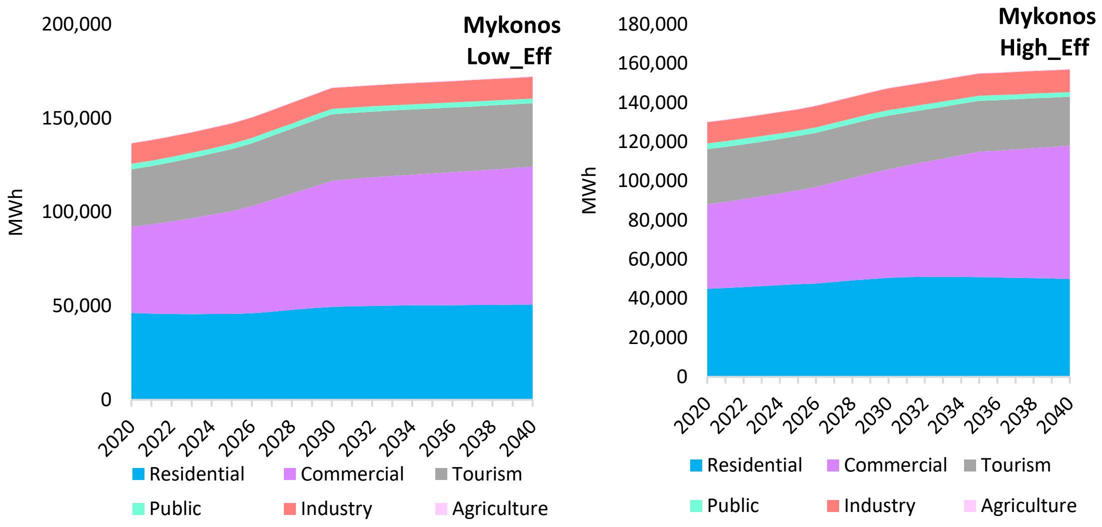


Figure 3.47: Low_Eff and High_Eff scenario results for Mykonos

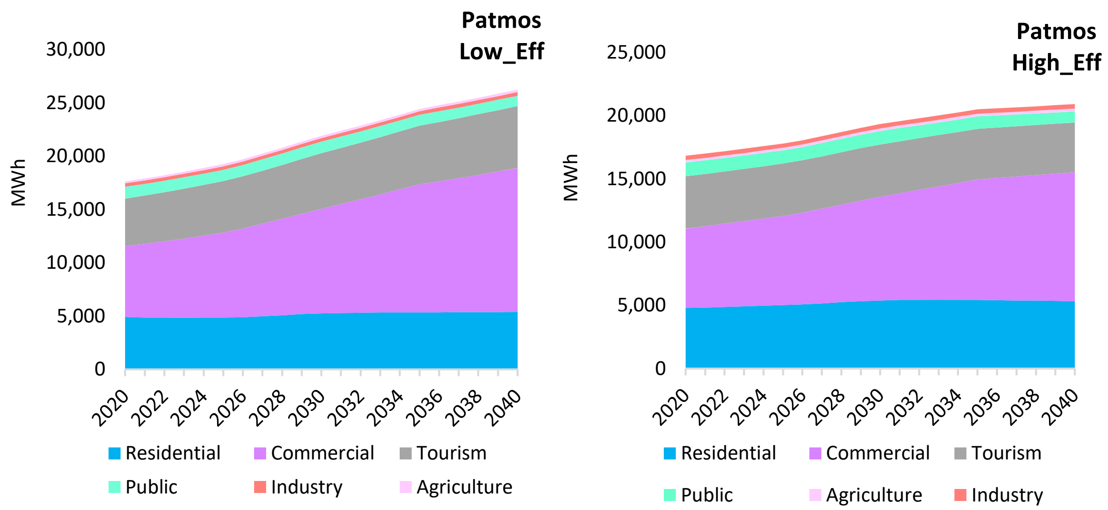


Figure 3.48: Low_Eff and High_Eff scenario results for Patmos

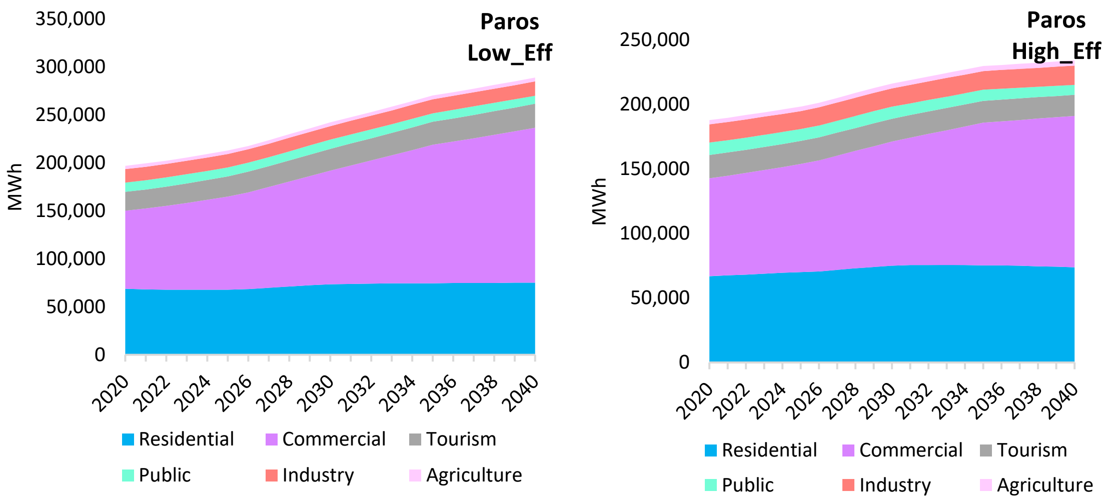


Figure 3.49: Low_Eff and High_Eff scenario results for Paros

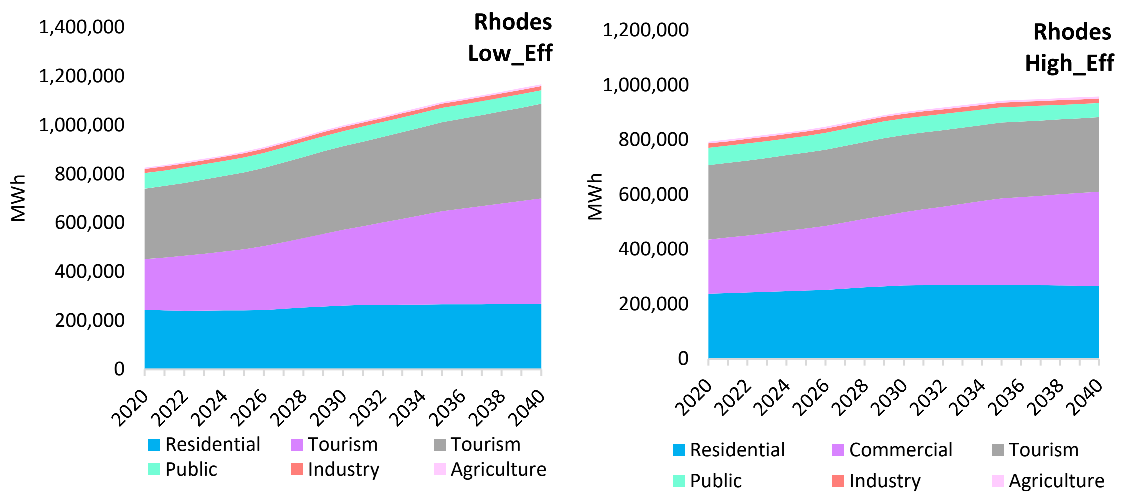


Figure 3.50: Low_Eff and High_Eff scenario results for Rhodes

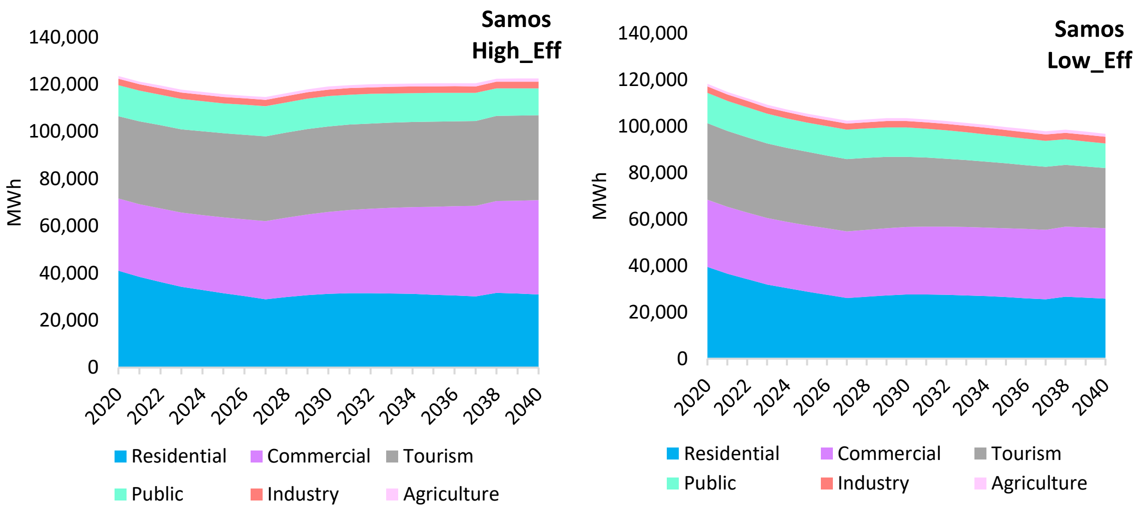


Figure 3.51: Low_Eff and High_Eff scenario results for Samos

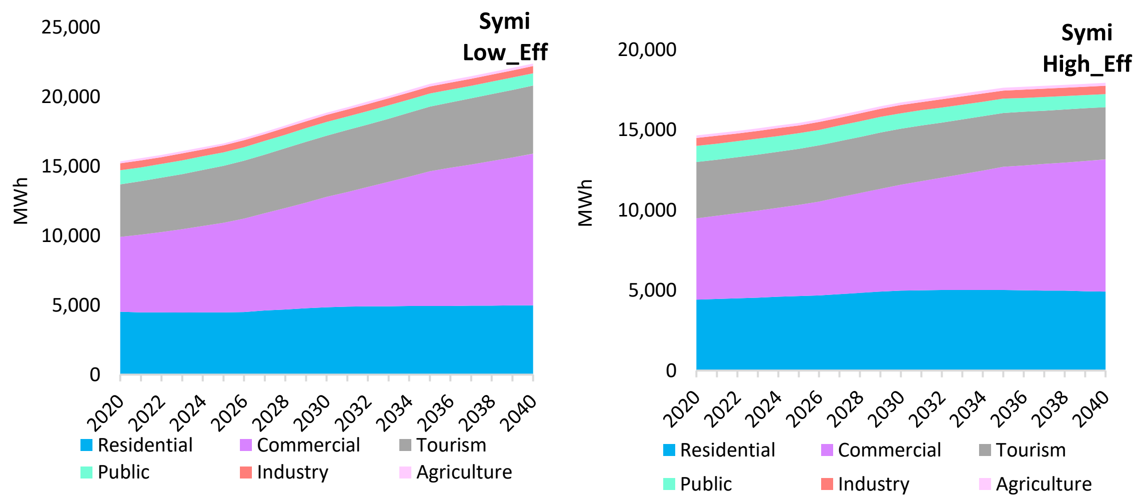


Figure 3.52: Low_Eff and High_Eff scenario results for Symi

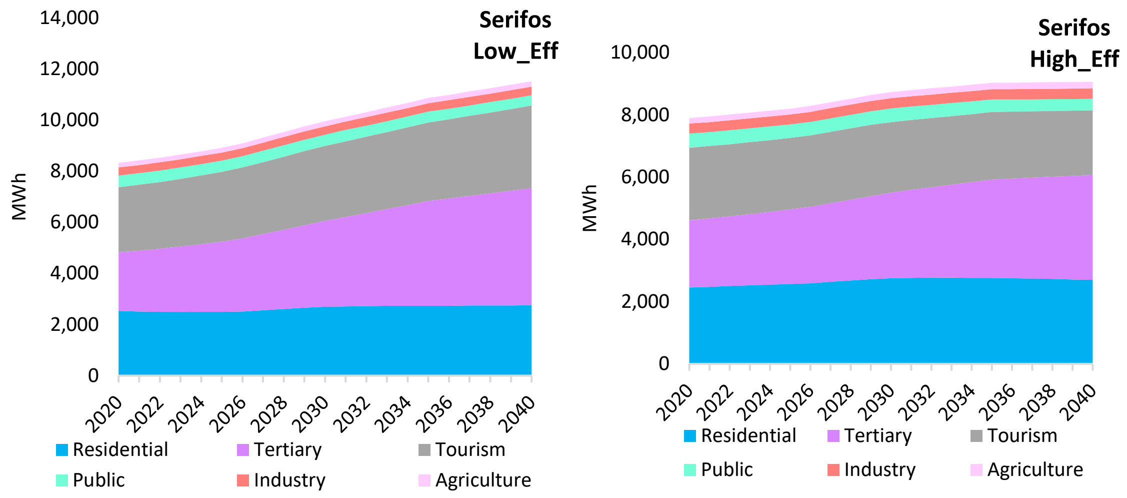


Figure 3.53: Low_Eff and High_Eff scenario results for Serifos

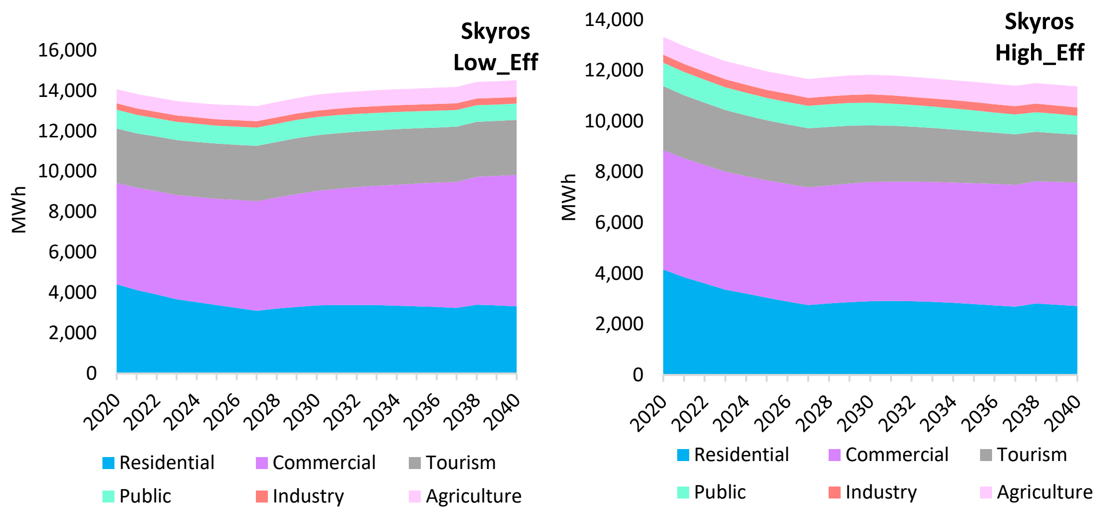


Figure 3.54: Low_Eff and High_Eff scenario results for Skyros

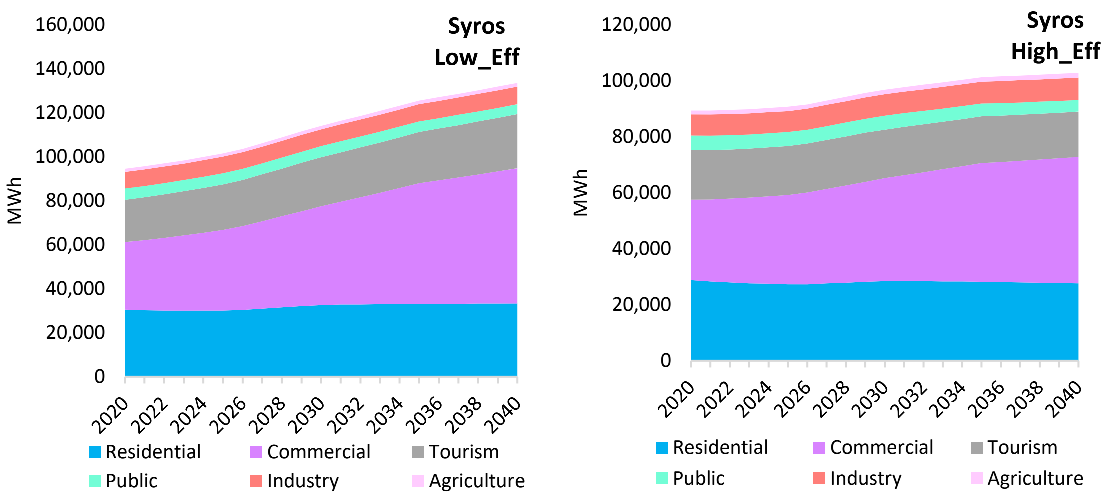


Figure 3.55: Low_Eff and High_Eff scenario results for Syros

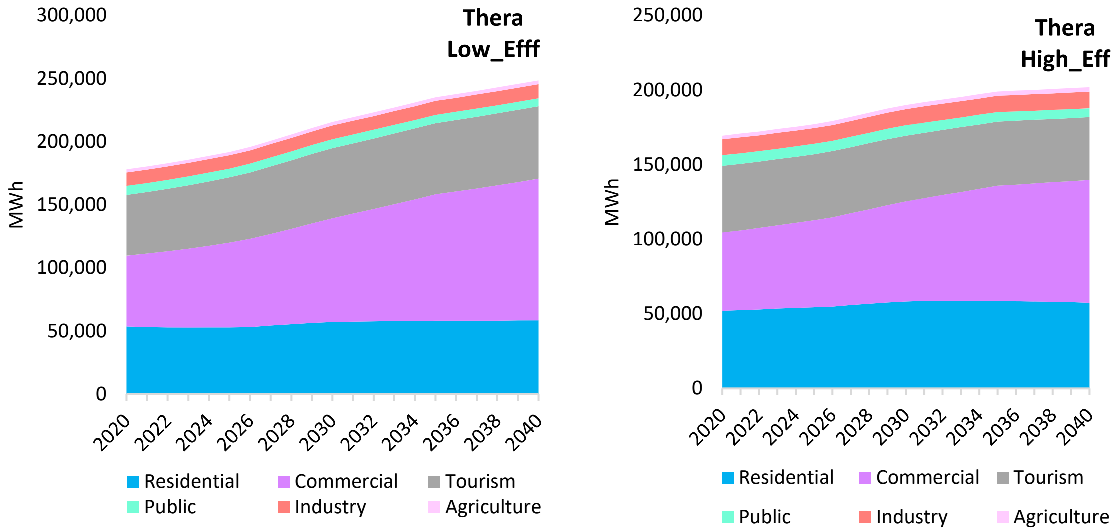


Figure 3.56: Low_Eff and High_Eff scenario results for Thera

3.7 Validation

In order to validate the applied bottom-up methodology, the 2016 annual demand profiles per electrical use were compared with the actual data from the same year. The only available source for such information concerned Crete's island from an exclusive energy study (E3MLab, 2016b). The historic analysis results display a satisfactory degree of confidence for the estimated residential demand split, illustrated in Figure 3.57. The only considerable discrepancies evidenced concern the lighting uses. This is because this methodology relies on data from 2012, and by 2016 it is assumed to have replaced a considerable amount of inefficient lighting bulbs. Furthermore, the assumption that all pensioners or economic dependent occupants will spend their entire day at home might have overestimated the actual consumption. This variation is incorporated into the growth factors to reflect the energy efficiency trend of the lighting sector. Regarding water heating, the assumption that 50% of the daily requirements are covered by solar systems or the Delta temperature hypothesis could have led to slightly lower estimates.

In the services sector, including commercial and tourism activities, the results were derived by data manipulation found in the EPC and not from an extensive survey. Hence, they might have led to minor discrepancies. Particularly, cooling loads have been over-estimated; hence the rest of the uses are under-estimated, leading to a smaller share in the ‘other uses’ category. Some of the explanations leading to this misalignment could be the representative sample comprising the set of EPCs, the hypothesis that all cooling systems are electrical or the 100% occupancy rate of office buildings. Despite the mismatches mentioned above, the order of magnitude between actual and calculated data remains the same among the various uses, as illustrated in Figure 3.58.

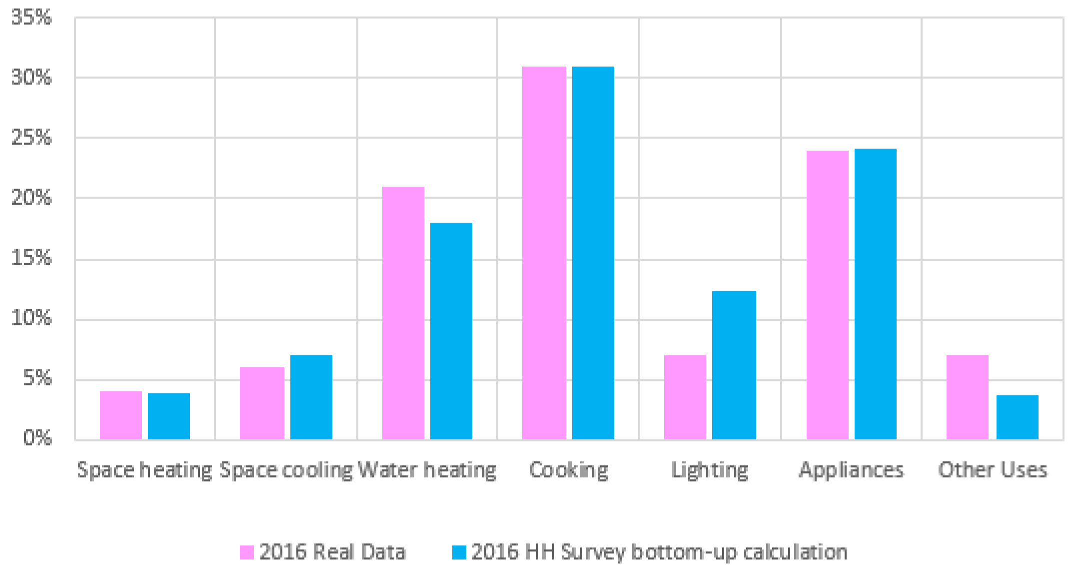


Figure 3.57: Comparison of 2016 real vs. calculated data in the residential sector

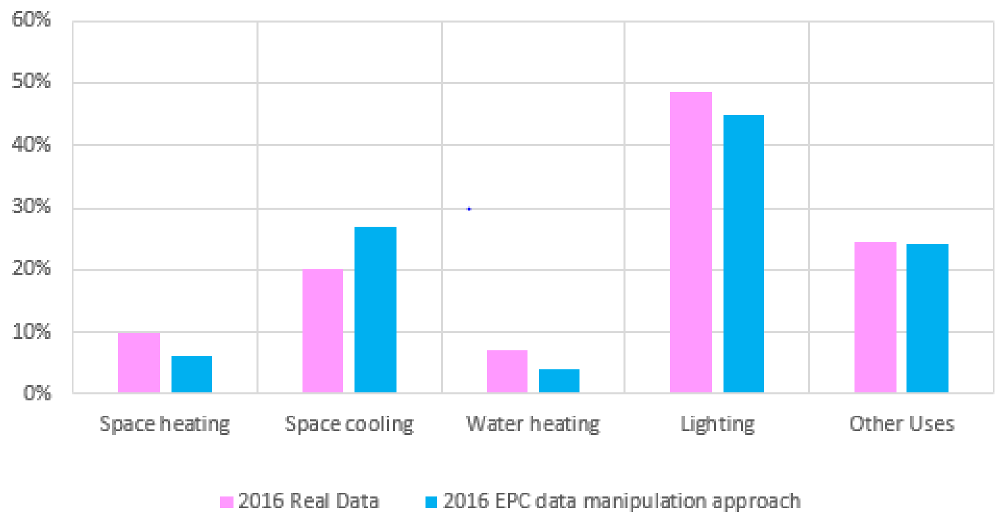


Figure 3.58: Comparison of 2016 real vs. calculated data in the services sector

The PRIMES energy model was developed by E3M - Lab at the National Technical University of Athens (NTUA). PRIMES simulates energy systems and markets on a region-by-region basis. The model provides projections of detailed energy balances for both demand and supply, GHG emissions, investment in demand and supply, energy technology penetration, prices and costs. The European Commission has extensively used it for impact assessments and strategic analyses (E3MLab, 2020). ISLA_EGI modelling results were compared with two equivalent PRIMES scenarios envisaging Crete's higher and lower electricity demand, excluding transport. PRIMES scenarios are rather investment-driven and not explicitly demand-driven concluding that the comparison between ISLA_EGI and PRIMES modelling results can only be indicative, while PRIMES scenarios are used herein to set the order of magnitude.

The first PRIMES scenario is an electrification scenario with high-RES penetration and enhanced interconnections, called ELC_M22. That scenario assumes relatively high-efficiency measures leading to high energy savings. Furthermore, renewables will reach more than 80% share by 2040. The second PRIMES scenario presented herein is the ‘Security of Supply Scenario’ (SEC_Supply), which assumes high electrification rates up to 60% across all sectors, with lower environmental performance.

The comparison highlights the Low_Eff Scenario's alignment with the SEC_Supply PRIMES scenario in Figure 3.59. Although the ISLA_EGI model projects a slightly more aggressive trajectory until 2035, by 2040, the results coincide as the PRIMES scenario picks up due to increasing electrification. Considering the ELC_M22 and the High_Eff Scenario, ISLA_EGI projects higher values than the PRIMES Scenario until 2035, attributed to the different input assumptions and modelling approaches. Specifically, between 2016 and 2020, the economic growth is slower in PRIMES assumptions, leading to a different starting point. In both cases, the demand growth factor is on the brink of zero. By 2035 the results coincide, while in 2040, the ELC_M22 scenario exceeds the High_Eff Scenario. This could be credited to intensifying energy efficiency measures recorded in the ISLA_EGI model, which flattened the curve. On the other hand, PRIMES assumes a rapid increase in electrification across most scenarios after 2035. Overall, the inclining trends demonstrate that the methodology of the

ISLA_EGI model is robust and underpinned by a valid narrative and data that could be generally applied to the rest of the Greek islands.

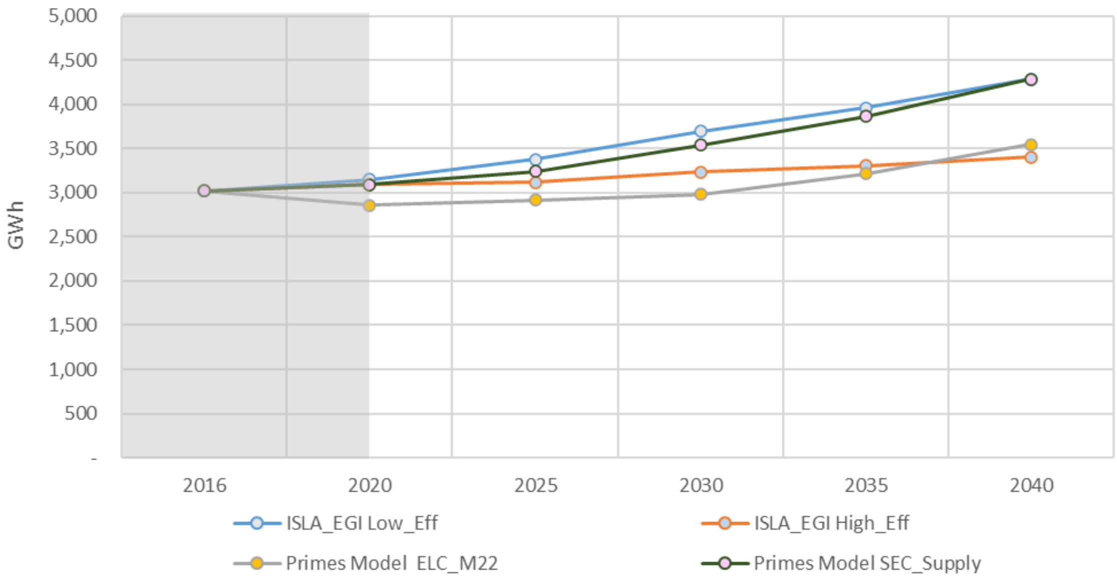


Figure 3.59: Electricity demand projections comparison between PRIMES and ISLA_EGI model concerning Crete island

Actual data for the Greek islands region for 2017-2020 were compared with ISLA_EGI modelling results in Figure 3.60. The results confirm the validity of the models' and the inputs assumptions with minor deviations between 2017 and 2019, demonstrating that the current trends coincide with the ISLA_EGI Low_Eff Scenario. In 2020, due to the COVID-19 pandemic, there is an unpredictable reduction in power consumption compared to 2019, equal to 8%, with the High_Eff Scenario scoring marginally lower.

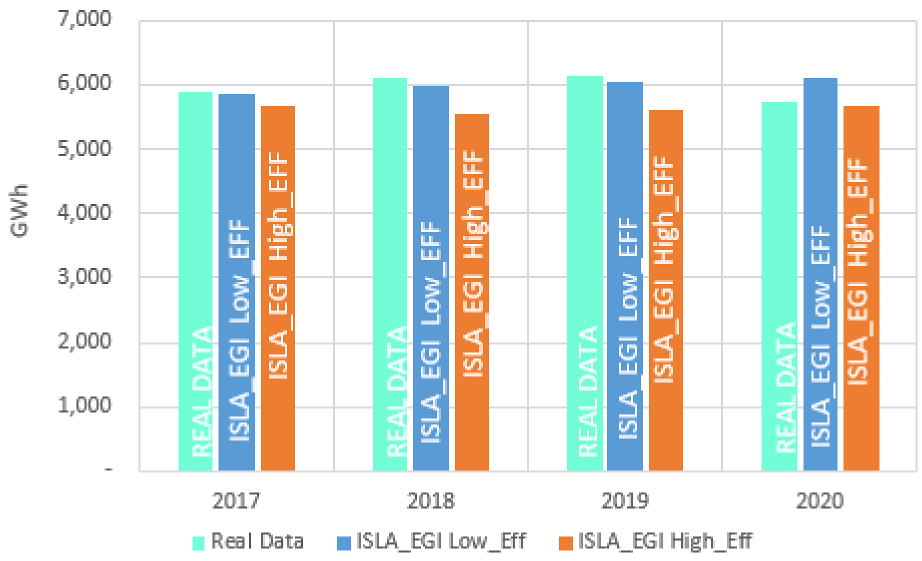


Figure 3.60: 2017-2020 electricity demand real data comparison vs. ISLA_EGI modelling results

The High and Low-Efficiency demand scenarios from ISLA_EGI were also compared with the demand projections identified in the literature (BAU Demand Scenario) used in the modelling analysis. The BAU Scenario was proposed by reports conducted for the state by the national universities and institutions such as the National Technical University of Athens (2008), HEDNO (2010), and IPTO (2014b). The results illustrated in Figure 3.61 prove that the BAU Scenario is exceptionally close to the Low_Eff demand scenario showing that both cases, despite different modelling approaches, encounter assumptions leading to a continuation of the current trends. On the other hand, the efficient scenario (High_Eff) envisaged in the ISLA_EGI model with assumptions leading to a breakthrough in efficiency measures compared to the current situation presuming 23% lower demand in 2040.

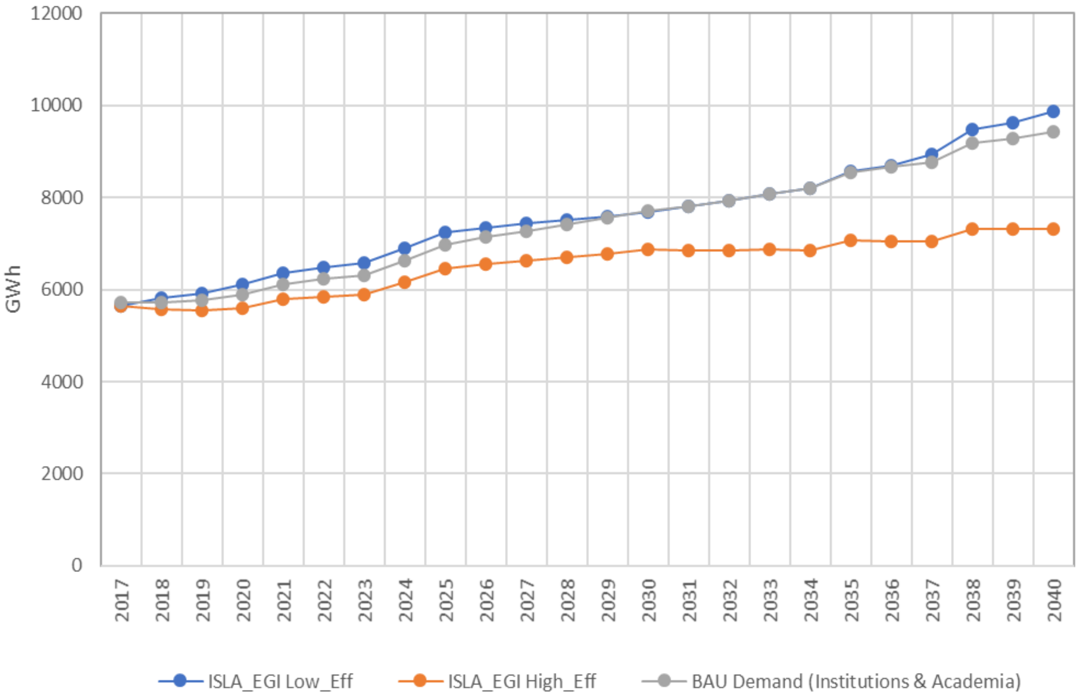


Figure 3.61: Comparison of total electricity demand from ISLA_EGI model scenarios vs. BAU scenario

4. Scenarios modelling for the autonomous and interconnected Greek islands’ electricity systems

4.1 Summary

This chapter describes the modelling tools and methods applied to simulate the Greek islands’ electricity system under a set of defined scenarios. Part of this chapter has been published in (Zafeiratou, Spataru and Bleischwitz, 2016; Zafeiratou and Spataru, 2018, 2019a, 2019b, 2022).

The scenarios incorporated in this analysis are presented considering two main storylines, the Autonomous and the Interconnected. Additionally, the consideration of battery storage split the two storylines into four pathways; the Autonomous pathway, the Autonomous pathway with Batteries, the Interconnected pathway and the Interconnected with the employment of Batteries. Under each of these pathways, sensitivity analysis is applied to deploy a set of assumptions. The narrative behind defining the Scenarios aims to answer the main Research Question:

Which is the optimal solution in the short and long term for enhancing the effective implementation of secure, affordable and sustainable electricity on the Greek islands?

Moreover, the electricity system model developed in PLEXOS is described. The model is used for the generation, storage and transmission expansion and optimisation of the electricity dispatch. The mathematical formulation and basic modelling principles, including operational constraints and suitability, are discussed. The spatial representation of the Greek electricity system includes 52 nodes and 20 transmission areas (regions) at an hourly temporal scale. Furthermore, the conventional and renewable generation technologies employed are presented alongside their techno-economic characteristics (i.e., heat rates, variable and fixed costs, fuel prices, lifetime, capacity factors etc.) and the ancillary services provided to the system. The methods applied to simulate the electrical network and the existing and future interconnections of the Greek islands with the mainland are also described. The technology and the sizing of each island's utility-scale batteries linked with wind energy are presented. Energy storage in the form of BESS is deployed under certain scenarios.

Finally, scenarios employing EVs are portrayed by considering various charging patterns to assess their impact on the islands' electricity system under the autonomous and interconnected operation. The scenarios are built in PLEXOS alongside a novel modelling approach for simulating the operation of EVs in power systems. This section sets the foundations for answering Research Objectives II to V related to the Energy Trilemma Index, i.e., energy affordability, security and sustainability in the region, as well as the impact of EVs against these criteria.

4.2 Proposed scenarios

4.2.1 Definition of Autonomous and Interconnection Scenarios

Hereafter, 35 trajectories for the Greek islands' electricity system are investigated and categorised in two main Storylines[27] (I & II). The current conditions of energy isolation combined with an oil-dominated electricity generation mix on islands contradict the sustainable framework that drives the European energy market. Thus, the first storyline **I) Autonomous** foresees the continuation of this autonomy over the projection horizon 2020-2040, comprising two key pathways a **Business as Usual (BAU) Autonomous** pathway and the **Autonomous-Batteries**. Furthermore, an alternative to interconnect the islands with the Greek mainland through submarine HV interconnections is envisaged in **II) Interconnection** Storyline, considering the **Interconnection** and the **Interconnection-Batteries** pathways. Each pathway is represented primarily through one 'Principal Scenario', each one reflecting a unique trajectory of the islands' electricity system (Table 4.1) specifically:

[27] Aligned with the IPCC terminology (IPCC, 2019b)

I. The first **Autonomous Principal Scenario** represents a BAU trajectory of the current autonomy, assuming that policies to support decarbonization established in 2016 will remain in place until 2040. Thermal generation restrictions in oil-fired units imposed under 2010/75/EU and 2015/2193/EU (European Union, 2010, 2015) will not be applied since that route would lead to an infeasible scenario where, during most of the year, demand cannot meet supply with continuous power cuts. Low Sulphur (LS) requirements are imposed as of 2020 only on the island of Crete as the largest system. Despite renewables increase, the condition for ensuring system dynamic security and stability enforce an upper threshold to the thermal production replacement from the renewable power, which may not exceed 30% of the previous calendar year's peak demand (Katsaprakakis and Christakis, 2009). The Cycladic interconnection[28] is not recognized for assessing the system in full autonomy. The demand evolves following the BAU Scenario as derived from the literature. The **Autonomous Scenario with Batteries** assumes that the examined AES will employ utility-sized BESS while imposing power generation restrictions to assess the response of the systems. This scenario considers LS used across all islands as the default option. The demand remains restricted to BAU.

II. According to the Directive 2009/72/EU (European Union, 2009b), interconnection infrastructure is essential for implementing the common regulations for the internal electricity market. While providing the necessary infrastructure of 18.2 GW, the **Interconnection Scenario** facilitates large-scale RES projects deployment. The scenario aligns with the Greek NECP regarding infrastructure and renewable energy deployment. It assumes that the original plan for connecting the Dodecanese islands through Crete with 560 MVA interconnection capacity in two phases will be applied, following a techno-economic evaluation of this option versus the new one proposed by the IPTO (2021b). Demand projections derive from the literature, such as BAU. Simultaneously, LS oil is utilised horizontally across the country. **Batteries** employment is also a supplementary technology to support

[28] Partially completed in 2019

systems reliability and higher renewable energy penetration in the Interconnected storyline.

Table 4.1: Principal Scenarios Description for the Greek islands

Principal Scenario	Max Interc. Capacity [29] (GW)	Gen. Restri-ctions	Max RES[30] Capacity (GW)	Max BESS Capacity (GWh)	Demand Scenario	Fuel & CO_2 pricing Scenario	No advancements
BAU Autonomous	0	×	1.1	0	BAU (literature)	New Policies/ LS Crete	No Offshore ProjectsNo Cycladic Interconnection
Autonomous-Batteries	0	✓	4.5	13.2		New Policies (LS)	No Cycladic Interconnection
Interconnection	15	✓	5.3	0			N/A
Interconnection-Batteries	15	✓	5.3	13.2			N/A

4.2.2 Sensitivity analysis

Sensitivity analysis assesses the impact of future policies, behavioural decisions and economic growth, forecasting the techno-economic performance at the island and at the national level. An extensive set of scenarios was developed for sensitivity analysis based on various renderings of the Principal Scenarios. Figure 4.1 illustrates the narrative followed to structure the 'Scenarios'. The labelling of the scenarios follows a typical pattern, consisting of 4-5 symbols, e.g., A.y.1.0.a (letters and numerals), representing five key indicators that are assigned to each scenario.

I. The two main Storylines: A & I and secondly the employment of battery storage technologies (B), define the pathways and, therefore, the prefix of each scenario's code name, where;
   - A. stands for autonomous;

[29] Referring to new HV interconnection capacity

[30] Including hydropower systems with reservoir and solar thermal technologies

- AB. stands for autonomous and batteries;
- I. stands for interconnection;
- IB. stands for interconnection and batteries.

II. The second letter (x or y) symbolises the imposition of power generation restrictions (x stands for hampering oil-fired generation till 1500 - 500 hours, y indicates that oil-fired units continue their operation driven by demand requirements as well as the merit order of dispatch).

III. The third letter shows whether an ambitious renewable energy scenario is employed or not (1 is yes, and 2 is no). This scenario assumes an available renewable capacity of 1.1 GW or 2 GW, including offshore, versus 0.8 GW for a moderate scenario in the autonomous state and 5.3 GW vs 2.6 GW in the interconnected. The actual RES capacity built is subject to cost optimisation modelling and certain conditions. For example, brownfield projects are prioritised over greenfield projects, while restrictions in RES installed capacity on islands are waived or relaxed following their interconnection.

IV. The fourth digit represents the adopted demand scenario pattern (0: BAU, 1: Low_Eff and 2: is the High_Eff Scenario produced by the ISLA_EGI model). The two models are soft-linked while integrating ISLA_EGI demand scenario results to PLEXOS as described in Chapter 3. Modelling outputs are utilised herein to define the two alternative demand scenarios.

V. Finally, the last, fifth letter, ranging between (a and f) is used to assign different fuel pricing scenarios, carbon prices, or testing the impact of the implementation of a particular generation and transmission expansion projects (e.g., Cycladic interconnection, offshore wind etc.) on the island systems' techno-economic operation.

Demand scenarios output alongside fuel price scenarios' outcomes are combined to form a specific narrative represented through various trajectories. Three oil fuel Scenarios have been included deriving from the 2018 WEO published by IEA(2018): the 'New Policies', the 'Current Policies' and the 'Sustainable', further described below. For example, the High_Eff Scenario is combined with IEA's low sustainable oil prices, assuming they are driven down by low demand, to form an aggressive decarbonisation scenario, e.g., I.x.1.2.b. Alternatively, a scenario where the minimum decarbonisation efforts are taking place (Low_Eff) could assume an increase in electricity and oil demand, e.g., I.x.2.1. These scenarios can occur both under autonomous or interconnected contexts. Overall, the complete set of Pathways and their respective Scenarios is depicted in Figure 4.2 and in Table 4.2, including an analytical description. The four Pathways are represented by four selected scenarios that denote the principal trajectory in the best manner.

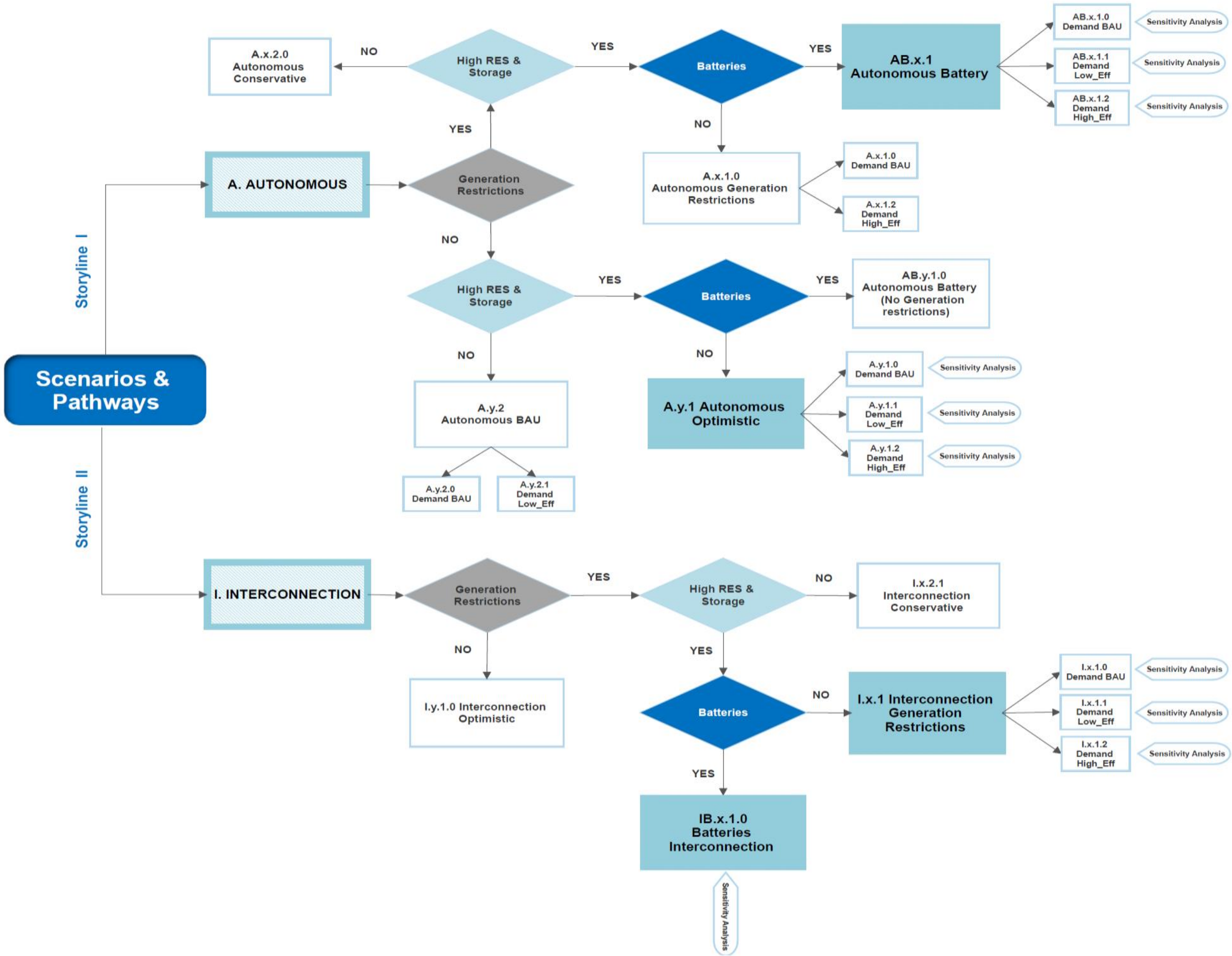


Figure 4.1: Pathways and scenarios definition pattern

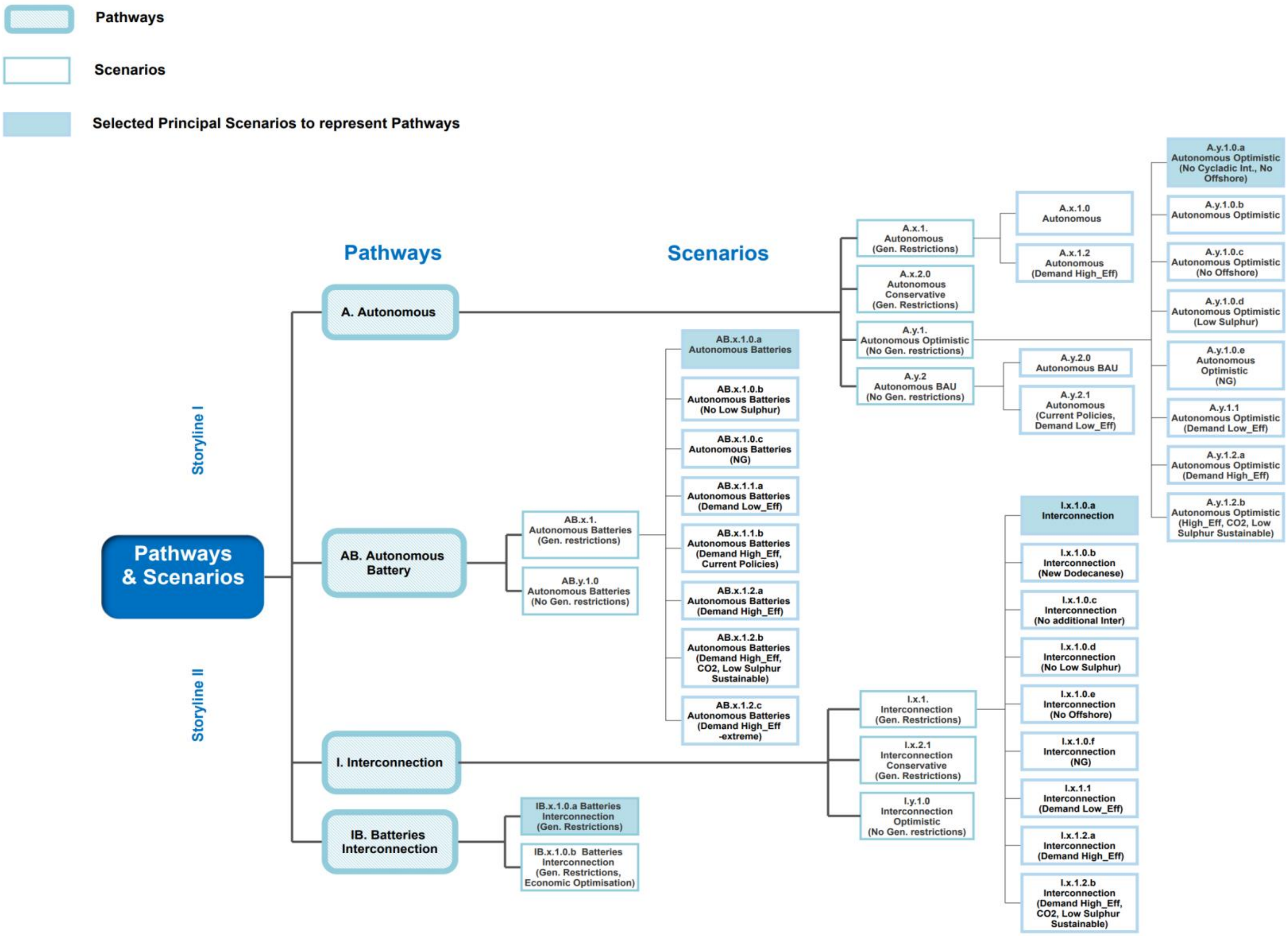


Figure 4.2: Pathways and their respective scenarios description

Table 4.2: Description of the full set of scenarios for the Greek islands

	Scenario	Scenario Description	Max Interconnection Capacity[31] (GW)	Generation Restrictions	Max RES[32] (GW)	Max Battery Storage Capacity (GWh)	Demand Scenario	Fuel & CO_2 pricing Scenario	No advancements
Autonomous Pathway									
1	**A.x.1.0**	BAU Scenario assuming that generation restrictions are imposed. Only policies and infrastructure projects before 2016 are considered, with a shift towards environmentally friendly fuels.	0	✓	1.1	0	BAU (literature)	New Policies/LS Crete	No Offshore Projects No Cycladic Interconnection
2	**A.x.1.2**	BAU Scenario assuming that generation restrictions are imposed. A High_Eff demand scenario is tested, to assess the impact on minimizing unserved demand.	0	✓	1.1	0	High_Eff (ISLA)	New Policies/LS Crete	No Offshore Projects No Cycladic Interconnection
3	**A.x.2.0**	BAU Conservative Scenario, assessing the impact of lack of renewables in such extreme conditions.	0	✓	0.8	0	BAU (literature)	New Policies/LS Crete	No Offshore Projects No Cycladic Interconnection

[31] Referring to new submarine HV interconnection capacity

[32] Including hydropower systems with reservoir and solar thermal technologies

4	**A.y.1.0.a** **(Principal Scenario)**	BAU Optimistic Scenario assuming that generation restrictions are not imposed. The rest of the policies and infrastructure projects in place before 2016 are considered.	0	✗	1.1	0	BAU (literature)	New Policies/LS Crete	No Offshore Projects No Cycladic Interconnection
5	**A.y.1.0.b**	BAU Optimistic Scenario assuming that generation restrictions are not imposed. Policies as well as infrastructure projects announced before 2016 are considered, including the Cyclades interconnection and offshore.	2.7	✗	2	0	BAU (literature)	New Policies/LS Crete	N/A
6	**A.y.1.0.c**	BAU Optimistic Scenario assumes that generation restrictions are not imposed. Policies as well as infrastructure projects announced before 2016 are considered. Offshore wind is not realised.	1.2	✗	1.1	0	BAU (literature)	New Policies/LS Crete	No Offshore Projects
7	**A.y.1.0.d**	BAU Optimistic Scenario assuming that generation restrictions are not imposed, testing the techno-economic impact of low Sulphur fuels.	2.7	✗	2	0	BAU (literature)	New Policies (Low Sulphur)	N/A
8	**A.y.1.0.e**	BAU Optimistic Scenario assuming that generation restrictions are not imposed. NG infrastructure is introduced on Crete.	2.7	✗	2	0	BAU (literature)	New Policies Natural Gas Crete	N/A

9	**A.y.1.1**	BAU Optimistic Scenario assuming that generation restrictions are not imposed. Assessing the impact of a Low_Eff demand scenario.	2.7	×	2	0	Low_Eff (ISLA_EGI)	New Policies/LS Crete	N/A
10	**A.y.1.2.a**	BAU Optimistic Scenario assuming that generation restrictions are not imposed. Assessing the impact of a High_Eff demand scenario.	2.7	×	2	0	High_Eff (ISLA_EGI)	New Policies/LS Crete	N/A
11	**A.y.1.2.b**	BAU Optimistic Scenario assuming that generation restrictions are not imposed. Assessing the impact of sustainable policies.	2.7	×	2	0	High_Eff (ISLA_EGI)	Sustainable (LS)	Aggressive CO_2 emissions costs
12	**A.y.2.0**	BAU Scenario assuming that generation restrictions are not imposed. Only policies and infrastructure projects in place before 2016 are considered.	0	×	0.8	0	BAU (literature)	New Policies	No Offshore Projects, No Cycladic Interconnection
13	**A.y.2.1**	BAU Scenario assuming that generation restrictions are not imposed. Assessing the impact of an ultra-conservative scenario where there is no successful implementation of the 2016 policies including efficiency policies.	0	×	0.8	0	Low_Eff (ISLA_EGI)	Current Policies	No Offshore Projects, No Cycladic Interconnection
Autonomous – Batteries Pathway									
14	**AB.x.1.0.a** **(Principal Scenario)**	Autonomous Scenario assuming the deployment of large-scale BESS and moderate decarbonization	1.5	✓	4.5	13.2	BAU (literature)	New Policies (LS)	No Cycladic Interconnection

		policies reflected in the use of Low Sulphur fuels							
15	**AB.x.1.0.b**	Autonomous Scenario assuming the deployment of large-scale BESS, excluding Low Sulphur fuels.	1.5	✓	4.5	13.2	BAU (literature)	New Policies	No Cycladic Interconnection
16	**AB.x.1.0.c**	Autonomous Scenario assuming the deployment of large-scale BESS. NG infrastructure is introduced in Crete.	1.5	✓	4.5	13.2	BAU (literature)	New Policies Natural Gas Crete	No Cycladic Interconnection
17	**AB.x.1.1.a**	Autonomous Scenario assuming the deployment of large-scale BESS, assessing the impact of a Low_Eff demand Scenario.	1.5	✓	4.5	13.2	Low_Eff (ISLA_EGI)	New Policies/LS Crete	No Cycladic Interconnection
18	**AB.x.1.1.b**	Autonomous Scenario assuming the deployment of large-scale BESS, assessing the impact of a Low_Eff demand Scenario combined with high fuel prices while excluding offshore wind.	0	✓	4.5	13.2	Low_Eff (ISLA_EGI)	Current Policies	No Cycladic Interconnection, No Offshore Projects
19	**AB.x.1.2.a**	Autonomous Scenario assuming the deployment of large-scale BESS, assessing the impact of a High_Eff demand Scenario.	1.5	✓	4	9.5	High_Eff (ISLA_EGI)	New Policies/LS Crete	No Cycladic Interconnection
20	**AB.x.1.2.b**	Autonomous Scenario assuming the deployment of large-scale BESS assessing the impact of a High_Eff	1.5	✓	4	9.5	High_Eff (ISLA_EGI)	Sustainable (LS) - Aggressive CO_2	No Cycladic Interconnection

		demand Scenario coupled with sustainable oil fuel prices.						emissions prices	
21	**AB.x.1.2.c**	Autonomous Scenario assuming the deployment of large-scale BESS assessing the impact of a High_Eff demand scenario under a strong decarbonization plan driven by high fuel and carbon prices.	1.5	✓	4	9.5	High_Eff (ISLA_EGI)	Current Policies - Aggressive CO_2 emissions prices	No Cycladic Interconnection
22	**AB.y.1.0**	Autonomous Scenario assuming the deployment of large-scale BESS with no generation restrictions.	1.5	×	4.5	13.2	BAU (literature)	New Policies/LS Crete	No Cycladic Interconnection
Interconnected Pathway									
23	**I.x.1.0.a** **(Principal Scenario)**	Interconnection Scenario with generation restrictions. Aligned with the NECP (2019) policy context regarding infrastructure and RES deployment.	13.6	✓	5.3	0	BAU (literature)	New Policies (LS)	N/A
24	**I.x.1.0.b**	Interconnection Scenario with generation restrictions. Aligned with NECP (2019) policy context regarding infrastructure and RES deployment. Assuming that the original plan for interconnecting the Dodecanese region (2008) is replaced by a new proposal (2019).	14.8	✓	5.3	0	BAU (literature)	New Policies (LS)	Alternative Dodecanese-NGS line

25	**I.x.1.0.c**	Interconnection Scenario with generation restrictions. Assuming lower interconnection capacity compared to the original plan.	12.5	✓	4	0	BAU (literature)	New Policies (LS)	Limited interconnection capacity
26	**I.x.1.0.d**	Interconnection Scenario with generation restrictions. Assuming that low Sulphur oil fuel is used only on Crete.	13.6	✓	5.3	0	BAU (literature)	New Policies/LS Crete	N/A
27	**I.x.1.0.e**	Interconnection Scenario with generation restrictions. Assuming that offshore wind projects are not realized.	12.3	✓	4.5	0	BAU (literature)	New Policies (LS)	No Offshore Projects
28	**I.x.1.0.f**	Interconnection Scenario with generation restrictions. NG infrastructure is introduced in Crete.	13.6	✓	5.3	0	BAU (literature)	New Policies Natural Gas Crete	N/A
29	**I.x.1.1**	Interconnection Scenario. Assessing the impact of a Low_Eff demand Scenario assuming part of the NECP (2019) policies regarding energy efficiency are not realized.	13.6	✓	5.3	0	Low_Eff (ISLA_EGI)	New Policies (LS)	N/A
30	**I.x.1.2.a**	Interconnection Scenario. Assessing the impact of a High_Eff demand scenario. Aligned with the NECP (2019).	13.6	✓	5.3	0	High_Eff (ISLA_EGI)	New Policies (LS)	N/A
31	**I.x.1.2.b**	Interconnection Scenario. Assessing the impact of a High_Eff demand scenario combined with ambitious decarbonization policies.	13.6	✓	5.3	0	High_Eff (ISLA_EGI)	Sustainable (LS) - Aggressive CO_2	N/A

								emissions prices	
32	**I.x.2.1**	Interconnection Scenario. Significant portion of the NECP (2019) decarbonization policies are not successfully applied.	11	✓	2.6	0	Low_Eff (ISLA_EGI)	Current Policies	No Offshore Projects, Limited interconnection capacity
33	**I.y.1.0**	Interconnection Scenario with no generation restrictions.	13.6	×	5.3	0	BAU (literature)	New Policies	N/A
Interconnections – Batteries Pathway									
34	**IB.x.1.0.a** **(Principal Scenario)**	Interconnection Scenario mingled with BESS. Fully aligned with the NECP (2019).	13.6	✓	5.3	13	BAU (literature)	New Policies (LS)	N/A
35	**IB.x.1.0.b**	Interconnection Scenario mingled with BESS. Here no certain conditions are introduced to the model for new built generation capacity. The model is governed solely by cost-optimization principles.	13.6	✓	5.3	13	BAU (literature)	New Policies (LS)	N/A

4.3 Methodological Approach

4.3.1 PLEXOS model

The Greek islands' electricity system was modelled using the PLEXOS integrated energy model, developed by Energy Exemplar (2019). PLEXOS is a software tool for energy planning, simulating and optimising electricity and gas markets utilised extensively by energy regulators, operators, and academic institutions worldwide. Modelling in PLEXOS can be performed by using deterministic or stochastic programming techniques aiming to minimise the total net present value of the system's costs as described in the objective function (Eq. 4.1). The model seeks the optimum generation mix associated with the techno-economic characteristics of the generation fleet and the electricity market design. This Objective function is subject to a number of constraints described in Eq. 4.2 to Eq. 4.6. The first constraint ensures that the electricity supply meets the demand constantly under the hypothesis that the generation capacity is sufficient. The following constraint respects the technical maxima and minima of the generation units. The third constraint concerns respecting the interconnection lines' thermal limits; the fourth constraint concerns the maximum allowed number of new units built within a year according to the commissioning schedule, which is considered an input in this analysis. Finally, the last constraint sets the availability of generation units controlled by the annual forced and planned outage rates.

PLEXOS uses AMMO software, a programming language developed exclusively to optimise linear equations (Deane, Drayton and Gallachóir, 2014). The NG and the NII systems were modelled in this study by the EELPS mathematical solver. Rounded relaxation of integer linear programming was used, as explained by Mc Garrigle and Leahy (2011).

Minimise:

$$\sum\nolimits_{y,g} DF_y * (BC_g * GB_{g,y}) + \sum\nolimits_{y} DF_y * FO\&M * Pmax_g * (Units_g + \sum\nolimits_{i \le y} GB\ Units_{g,i}) + \sum\nolimits_{t} DF_y * \ GL_{g,t} * (HR * Fuel\ Price + VO\&M) + \sum_{t} DF_{t\epsilon y} * L_{\ t} * (VOLL * USE_t)$$

Eq. 4.1

Where:

'g' is the generator;

't' is the dispatch period;

'DF' is the discount factor [$DF_y = 1/(1 + D)^y$ where 'D' is the discount rate];

'y' is the ultimate year of the projection horizon considered in the model;

'BC_g' is the overnight build cost of generator 'g' or transmission line;

'GB_g' is the number of generating units build in the year 'i' for generator 'g';

'FO&M' is the fixed operations and maintenance cost of generator 'g' including also abatement costs;

'Pmax' is the maximum generating capacity of each unit of 'g';

'Units' is the number of installed generating units of 'g';

'GB Units' is the number of built generating units of 'g';

'GL' is the dispatch level of generating unit 'g' in period 't';

'HR' is the heat rate;

'VO&M' is the variable operations & maintenance costs including also emissions and abatement costs;

'L_t' is the duration of dispatch period 't';

'VOLL' is the value of lost load (energy shortage price);

'USE' is the unserved energy.

This equation is subject to a number of constraints:

$$\text{Energy Balance: } \sum_{g} \mathrm{GL}_{g,y} + \mathrm{USE}_t = \mathrm{Demand}_t \ \forall \mathrm{t}$$

Eq. 4.2

$$\text{Feasible Energy Dispatch: } \mathrm{Pmin}\,(Units_g + \sum_{i \le y} \text{GB Units}_{g,i}) \le GL_{g,t} \le Pmax(Units_g + \sum_{i \le y} GB\ Units_{g,i})$$

Eq. 4.3

$$\text{Transmission Lines Limits: } Lineflow \le Linemax$$

Eq. 4.4

$$\text{Feasible Builds: } \sum_{i \le y} GB_{g,i} \le MaxGB\ Units_{\ g,y}$$

Eq. 4.5

$$\text{Availability: } GenCap_g \le \mathrm{Pmax}_g - \mathrm{Outage}_g$$

Eq. 4.6

Where: 'MaxGB Units' is the maximum number of units of generator 'g' allowed to be built by the end of year 'y'

PLEXOS provides flexibility in spatio-temporal resolution, allowing for long-term generation and transmission expansion planning with annual time steps while emulating electricity dispatch in full resolution at an hourly level. It also addresses the fundamental component of the ETI, as it ensures the balance of demand and supply, models capacity reserves, and analyses the environmental effect through carbon costs and shadow pricing and cost minimization. The model's setup in PLEXOS includes the static and dynamic data and three interrelated chronological simulation modules: the 'Long Term (LT) plan', the 'Medium-Term (MT) Schedule' and the 'Short-Term (ST) Schedule' are developed to cover different chronological granularities, and finally, the auxiliary simulation phase called "Projected Assessment of System Adequacy (PASA)", as illustrated in Figure 4.3.

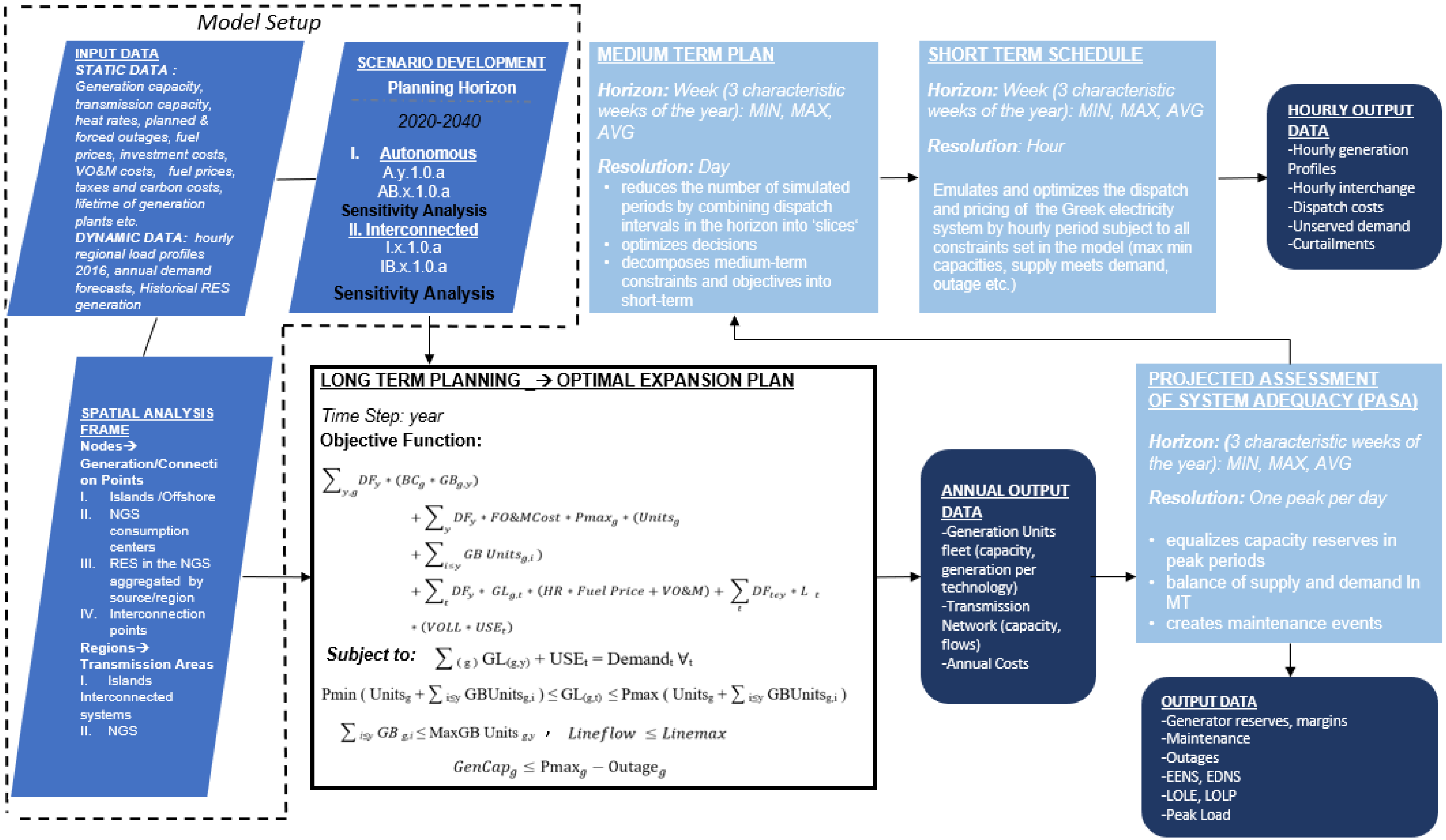


Figure 4.3: Modelling approach developed in PLEXOS of the Greek islands

The **'Long Term (LT)'** phase involves the development of generating, storage and transmission capacity, as well as the dispatch of power from central planning. The planning module of the LT expansion, which operated between 2020 and 2040 with yearly time steps, utilised a quarterly load duration curve with 12-time slices and an hourly resolution. Therefore, the existing and future (candidate) capacity of the island's generation, storage and interconnections, as well as retirements, are taken into account. The LT plan was run once, integrating all samples into a stochastic optimisation that resulted in a single set of optimum capacity expansion options and a single generation solution. To adjust the annuity calculations, a 'Declining Depreciation Balance Method' has been used for new constructions throughout the LT period in relation to the tax and inflation rates. Annualized build costs of a generator, transmission line, or storage system based on the project's 'Weighted-Average Cost of Capital (WACC)', applied in the year of construction and every following year for each project (generation/transmission/storage). The economic parameters used in the simulation analysis of the LT plan per unit (u) are summarised in Table 4.3.

$$Annuity_i = BuildCost_u * \frac{1 - \frac{TaxRate * DeclingDepreciationBalance_u}{WACC + InflationRate + DeclingDepreciationBalance_u}}{RealAnnuityFactor}$$

Eq. 4.7

Where:

$$RealAnnuityFactor = \frac{1 - (1 + WACC)^{-Economic\ Life}}{WACC}$$

Eq. 4.8

$$DeclingDepreciationBalance_u = \frac{1}{EconomicLife_u} * DeclingDepreciationBalance_u$$

Eq. 4.9

Table 4.3: Economic indicators (Hellenic Republic - Ministry of Finance, 2013; Competitions & Market Authority, 2015; Trading Economics, 2018; WACC Expert, 2018)

Economic Indicator (Average 2020-2040)	Value
Tax Rate	24%
Inflation	0.80%
WACC (Generators)	8%
WACC (Transmission Lines)	9%
Discount Rate	6%
Economic Life (Generators)	20 years
Economic Life (Transmission Lines)	35 years

The '**Projected Assessment of System Adequacy (PASA)'** simulation creates maintenance events after the LT plan is completed for the following simulation phases MT and ST, and computes reliability statistics. The resolution considered herein is one peak per day. The PASA uses an optimisation that focuses on the balance of supply and demand in the medium term. Furthermore, it estimates the optimal size of capacity reserves to be shared among areas using the transmission network as explained in Eq. 4.10. Also, the analogous capacity reserve margin (CRM) is considered according to Eq. 4.11. The PASA does this by formulating the problem of equalising region capacity reserves as a quadratic programming problem. PASA is used to produce outputs such as the projected capacity in excess of Peak Load subjected to maintenance and forced outages events described in Eq. 4.12. The 'Forced Outage Rate (FOR)' (Eq. 4.13) determines the number, timing and severity of these events set as modelling input for each type of generation unit, alongside the mean, maximum and minimum time to repair, the repair time distribution and the outage rating to define the severity of outage events.

$$\text{Capacity Reserves} = \sum(Generators\ Capacity) - Peak\ Load - Discrete\ Maintenance - Distribution\ Maintenance - Expected\ Forced\ Outage - Net\ Capacity\ Interchange$$

Eq. 4.10

$$CRM = {}^{Capacity\ Reserves}/_{Peak\ Load}$$

Eq. 4.11

Where: 'Region Distributed Maintenance' is the maintenance allocated by the optimisation to level the regional capacity reserves.

$$Expected\ Forced\ Outage = \sum Generators\ Capacity\ (Rated) * Generator\ FOR$$

Eq. 4.12

$$FOR = {}^{FOR_h}/_{(O_h + FOR_h)}$$

Eq. 4.13

Where:

'FOR_h' are the forced outage hours;

'Oh' are the operating hours.

Furthermore, the most common indictment used for security of supply assessment in the PASA phase is the 'Loss of Load Probability (LOLP)'. The numbers are placed into a 'capacity outage probability table' incorporating scheduled and forced outages that iterates through all system units, yielding the 'Load Duration Curve (LDC)' for the peak PASA area load. Based on the convolution provided, this updated curve is then utilised to get them through LOLP on a region-by-region transmission per PASA period (Eq. 4.14). The 'Loss of Load Expectation (LOLE)' is considered in Eq. 4.15, which is the number of outage days calculated directly from the LOLP. Beyond the loss of load indicators, the 'Expected Energy Not Supplied (EENS)' is determined by taking the total area where the demand is greater than the available capacity supply multiplied by the number of hours in each PASA period. Considering the suitability criteria for this research, they were selected as attributes for the reliability criterion.

$$LOLP \ = \sum_{1}^{N} fy * Cc * Fd * (InCap - Cc)$$
$$for\ 1\ to\ N\ PASA\ periods$$

Eq. 4.14

Where:
'Cc' is the capacity outage (MW);
'fy' is the probability that a capacity outage, Cc happens;
'InCap' is the installed capacity for the region;
'Fd (InCap-Cc)' is the value of the built LDC equal to InCap-Cc.

$$\mathrm{LOLE} \ = \ \mathrm{LOLP} \ * \ \mathrm{t} \,/\, 24$$

Eq. 4.15

Despite LOLP being calculated by PLEXOS on a regional basis without considering transmission capacities, the 'Multi-regional LOLP' considers flow limits and solves interconnected regions together, thus considering the probability of failure of units or transmission lines supporting neighbouring regions. These flows are bounded by the input line max flow, min flow and/or min, max rating. Transmission unreliability is not considered herein, assuming the transmission line is completely reliable and voltage balance constraint is not applied (Energy Exemplar, 2020). In order to consider planned and forced outages transmission, the transmission unavailabilities reported out of Monte Carlo Simulation, as explained in 4.4.1, were input as limits to the 'Multi-regional LOLP' run before executing it for the second time for the sake of this analysis.

Before moving on to the 'Short Term (ST)' phase to model the system in full chronological resolution, the '**Medium Term (MT)'** phase allows for optimising medium to long-term decisions. This primarily refers to hydro storage, fuel supply, and pollution limitations. A weekly horizon has been selected with a daily time step, allowing for a time decomposition in accordance with chronology (Energy Exemplar, 2019).

The MT results are inputs to the '**ST module'** at full chronological optimisation during the last stage, using an hourly time step and round relaxation. Cost optimisation obtains the least-cost dispatch of each power plant; in other words, the merit order power system meets a given demand profile. The ST emulations were performed for three weekly representative horizons per year, considering the following loads: average (AVG) - 23 to 29 of May, maximum (MAX) – 10 to 16 of August, and minimum (MI) 17 to 23 of November. In order to select the three representative weeks, hourly data for 2016 alongside 4-year monthly data (2012-2015) on each electrical region were processed according to Hatziargyriou (2012) and HEDNO (2019b, 2020a).

The ST simulates the hourly price paid by the load expressed as the 'System Marginal Price (SMP)' per electrical region (Hellenic Republic - Ministry of the Environment and Energy, 2020b). The SMP is the price at which the electricity market is cleared. This price is received by the individuals who inject energy into the system as well as the value consumers pay before taxes and additional fees, supply-profits etc. In particular, the SMP is formed by the combination of 'Short Run Marginal Cost (SRMC)' calculated according to Eq. 4.16 and quantities submitted daily by the available power plants, and the hourly load of electricity demand, which is formed on a daily basis (Institute for Energy for South-East Europe (IENE), 2019; RAE, 2020b). A perfect market is considered in our simulations (i.e., no market power or bidding behaviour and power plants bid their short-run marginal cost). Pricing in Greece takes place in one single zone considering the whole country, i.e., zonal pricing. In the model, the price is calculated for the NGS. If an island's electrical system becomes interconnected, the island becomes part of the national grid network; therefore, the national SMP applies. Crete will constitute a distinct bidding zone following its complete interconnection; however, such a simulation is out of the scope of this research.

$$SRMC = (Fuel\ Price * Marginal\ HR) + VO\&M + Emission\ Cost + UoS\ Charge \qquad \text{Eq. 4.16}$$

4.3.2 Spatial and temporal representation

The Greek electricity system is defined in PLEXOS by six (6) electrical nodes in the mainland and 46 electrical nodes in the islands region. Nodes are the basic connection locations for transmission lines, generators, and other components like purchasers in PLEXOS. The term 'node' could be used interchangeably with 'bus' (Lin and Magnago, 2017). In practice, they represent consumption and/or generation points that stand alone as 'transmission regions (R)' in small, isolated islands or form broader systems through interconnections among islands. Each island is represented with one node in this model, except Crete, with three nodes denoting the three major consumption centres. Also, one node is assigned to each offshore project located in the Aegean Sea. These nodes form 20 regions representing the Greek electricity system network, as illustrated in Figure 4.4. The existing interconnections concern HV (150 kV and 400 kV) lines on the Greek mainland and MV for the Greek islands; exceptions remain in the ongoing Cycladic and Crete interconnection projects[33]. The cross-border energy offers for energy injection (imports) and energy withdrawal (exports) are included as inputs in the model according to data collected from the IPTO (2020b) and the Aristotle University of Thessaloniki (A.u.Th) by Biskas (2021).

Future interconnections concern only HV transmission cables among the islands. By considering an individual node for each island, the spatial resolution of the model is increased compared to previous models representing the Greek islands at the regional transmission level, usually considering one or a group of regions (Lignos and Tsikalakis, 2015; Georgiou, 2016; Kapsali, Kaldellis and Anagnostopoulos, 2016; Koltsaklis *et al.*, 2016). The high granularity in the spatial representation allows capturing the individualities of each island considering the consumption and the injection of power as well as the intermittent local particularities concerning RES. For example, the hourly outputs of a 1 MW solar project on three different locations, including Crete vs Chios Island and the Central Part of the Greek mainland, are illustrated in Figure 4.5. The depiction shows

[33] Phase I & II Completed in 2021. The first phase of Crete's interconnection is under completion.

substantial discrepancies in the hourly output, demonstrating the impact of geographical diversity in terms of RES generation.

Five years (2012-2016), wind and solar hourly profiles were added in the model as samples to reflect their stochasticity at each node simulated to improve the renewables' intermittent accuracy (Pfenninger and Staffell, 2018). The inclusion of five years allowed to increase in the temporal accuracy as there is usually a substantial annual deviation especially concerning wind energy. Figure 4.6 highlights the chronological diversity by comparing wind generation profiles of 2012 against 2016 concerning Central Crete.

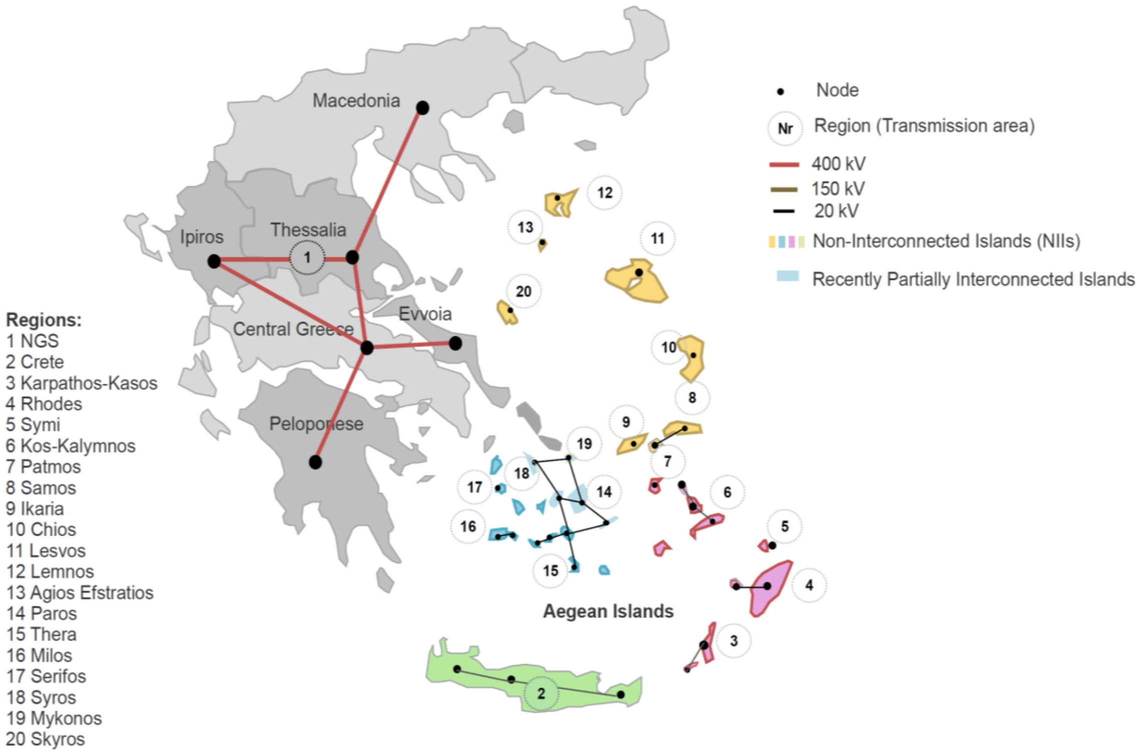


Figure 4.4: Existing interconnections (2020) in the Greek islands' region

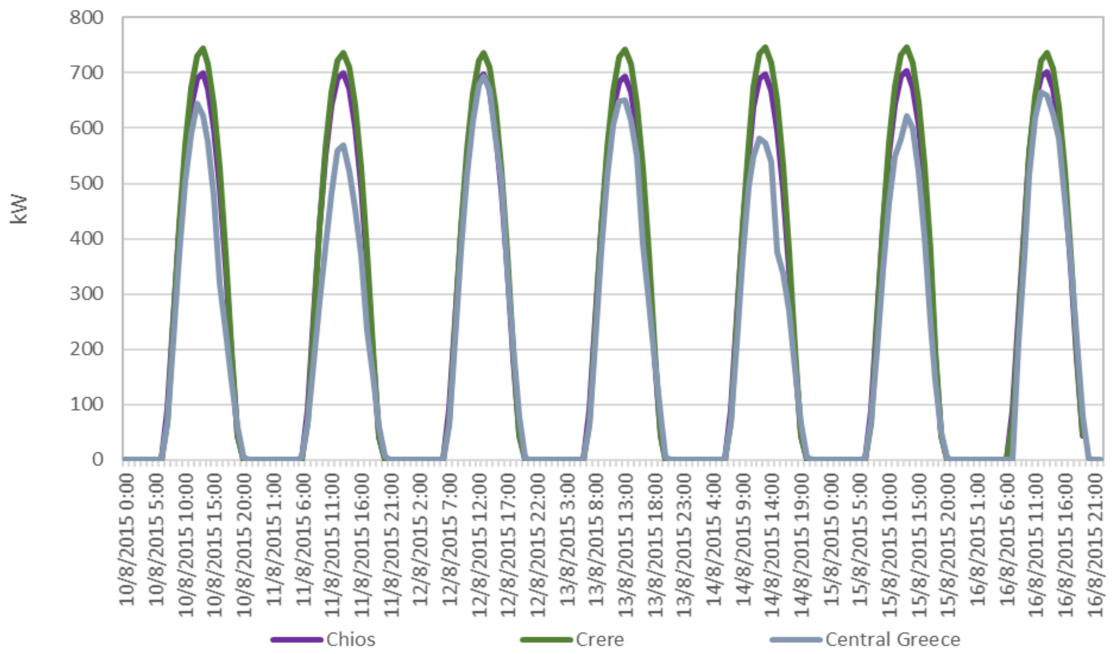


Figure 4.5: Simulated hourly output for one week from 1 MW of PV solar systems (Pfenninger, S., Staffell, 2018)

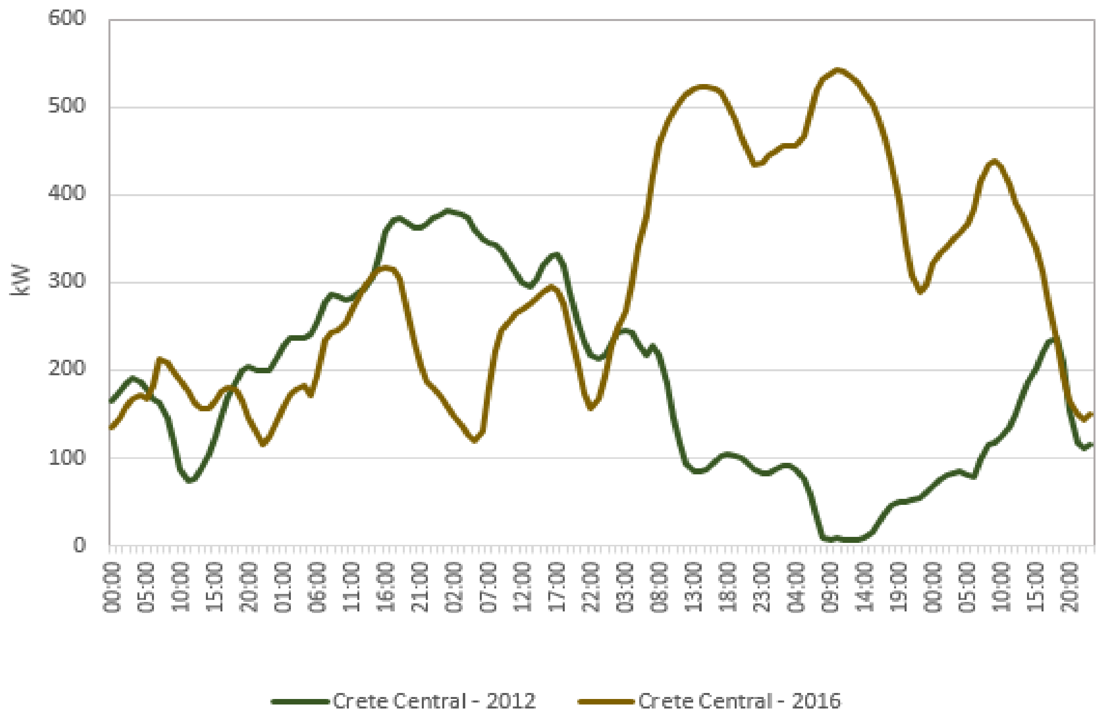


Figure 4.6: Simulated hourly output for the same week in August 2012 and 2016 from 1 MW W/T in Central Crete (Pfenninger, S., Staffell, 2018)

PLEXOS performs load forecasting over the horizon at an hourly level by considering the base year demand load profiles, the total projected annual demand (GWh) and the peak demand (MW). For each region, an hourly load profile is an input in the model for the base year 2016, according to data derived from the Ministry of Environment Energy & Climate Change (2018); HEDNO (2019a); University of West Attica (2019). The data are derived from the IPTO (2016) considering the NGS. Demand forecasts in PLEXOS are exogenous; therefore, the three annual demand scenarios (BAU and ISLA_EGI High_Eff, Low Eff) are inserted in the model. In the NGS, one BAU demand scenario is considered (IPTO, 2015, 2021b; Hellenic Republic - Ministry of the Environment and Energy, 2019a).

Because the load profile data do not pertain to nodes (islands) but electrical systems (regions), each node was given a load participation factor that divided the entire load into activities attributable to the local population and tourism. Loads generated exceeding 12% of the average hourly load between May and September (Touristic period) and December (Christmas period) are attributed to tourism activities, while the rest is assigned to local population activities. The tourist weight factor was calculated using data on lodging facilities on each island from the Hellenic Chamber of Hotels (2019), whereas the population weight factor was calculated using local population data (Hellenic Statistical Authority, 2012a; Gavalas, 2017). The Load Participation factor (Lpf_i) for each node/island (i) [34] was calculated according to Eq. 4.17.

$$Lpf_i = Lp_R * Wf_i(p) + Lt_R * Wf_i(t)$$

Eq. 4.17

Where:

'Lt' is the load attributed to touristic activities per region;

'Lp' is the load attributed to local population activities per region;

'Wf_i (p)' is the population weight factor per island/node;

'Wf_i(t)' is the tourism weight factor.

[34] Demand for the offshore wind nodes was assigned to zero

4.4 Generation capacity

4.4.1 Conventional thermal generation

Thermal generation on the Greek islands includes diesel and HFO; usually, mazut is burned in diesel engines, gas or steam turbines. On the mainland, power generators concern lignite and natural gas power stations, with most capacity being located in Northern Greece, where lignite mines exist. The respective local thermal generation capacity was modelled on a unit-by-unit basis considering 352 units across all electrical regions. Table 4.4 indicates the key techno-economic characteristics of each generator type. Specific parameters such as heat rates at load level, minimum uptime and maximum downtime, and max ramp rates (Table 4.5) and their associated costs are used only in the full resolution mixed-integer ST simulation in PLEXOS. The model creates a piecewise linear model of the marginal heat rate function from the data, characterising the heat input function points (Energy Exemplar, 2020). According to the usual heat rate function of a thermal unit, heat rate was input at three load points: 50% (if min stable level is lower than 50%, then min stable level), 75%, and 100% of total net capacity (Lew et al., 2012). The generation costs consist of the VO&M and fuel costs, and the total generation costs also include the fixed costs.

The assumptions proposed by this research were based on the commitments included in the NECP (Hellenic Republic - Ministry of the Environment and Energy, 2019c) that the European Commission approved in 2019. The units included in the model were those in operation on the 31st of December 2016, as 2016 is considered the base year of the model. The cut-off date for all the modelling assumptions was 31/12/2019, considering policies and plans published before that date to allow sufficient time for refining the modelling exercise and data analysis. Furthermore, according to the announced mid-term strategic priorities and financial prospects of the PPC, all existing lignite-fired power plants will be withdrawn from the Greek power system by the end of 2023 at the latest, and any derogations can be extended until 2028. The lignite power station 'Ptolemaida V' entered into commercial operation in January 2022; therefore, it is considered available for the entire study period (until 2040). Following 2028 natural gas will be utilised in all scenarios as an acceptable alternative fuel compliant with the recent official commitments of the Greek State.

New units built in PLEXOS as part of the generation expansion modelling in the LT are included in the model as 'units-candidates'. The model economically optimises the system under the obligation to meet the demand for the addition of a candidate unit. For the Greek islands' candidate thermal units, the latest diesel and gas turbines, similar to those commissioned between 2012 and 2016 with improved techno-economic characteristics, will be included as there is no available upgrade plan. New generators concern only natural gas power stations in the Greek mainland, similar to the most recent investments as presented ANNEX II.b. Indicatively the following power stations have commenced their permitting procedure:

I. new CCGT gas-fired generating unit in Northern Greece with a net capacity of 660 MW.
II. a new gas-fired generating unit in Central Greece with a net capacity of 660 MW,
III. a new gas-fired generating unit of Northern Greece with a net capacity of 803 MW,
IV. a new gas-fired generating unit in Northern Greece with a net capacity of 650 MW,
V. a new gas-fired generating unit in Central Greece with a net capacity of 651 MW.

Table 4.4: Indicative operating parameters for thermal power generator units (Hatziargyriou *et al.*, 2001; Kumar *et al.*, 2012; National Renewable Energy Laboratory, 2012; Egill Thorbergsson *et al.*, 2013; U.S. Energy Information Administration, 2016a; Wartzila, 2016; HEDNO, 2017a; European Commission, 2020a)

Generator Type	**Tech. Life**	**Heat Rate**	**Min up time (warm)**	**Min downtime (warm)**	**Max Ramp Rate**
	(years)	(GJ/MWh)	(hour)	(hour)	(MW/min)

Steam Turbines	30	11-15	4.5	4	0.2-0.3
Gas Turbines	20	11-20	0.3	0.15	10
Diesel <20 MW	25	9-10	0.1-0.2	0.1	12
Diesel ≥20 MW	25	9-10	0.1-0.2	0.1	12
CCGT	25	9	1.8	1.2	5
Diesel (Natural Gas)	25	7.8	0.1	0.05	12
CCGT Natural Gas	30	7.2	1	0.5	6.6

Table 4.5: Economic parameters for thermal power generation units (Hatziargyriou *et al.*, 2001; Kumar *et al.*, 2012; National Renewable Energy Laboratory, 2012; Egill Thorbergsson *et al.*, 2013; U.S. Energy Information Administration, 2016a; Wartzila, 2016; HEDNO, 2017a; European Commission, 2020a)

Generator Type	**VO&M**	**FO&M**	**Build cost**	**Start-up cost**	**Shut-down cost**
	(€/MWh)	(€/kW/year)	(€/KW)	(€/MW)	(€/MW)
Steam Turbines	1.3	60	1,200	8	6.8
Gas Turbines	2	27.5	550	7	6.2
Diesel <20 MW	0.9	45	900	12	10.8
Diesel ≥20 MW	1.2	29	900	8	6.7
CCGT	1.8	37	750	6	5

Diesel (Natural Gas)	3	29	1,525	8	7
CCGT (Natural Gas)	2.5	30	730	6	5

Based on outage records from 2015 and 2016, the forced outage for each traditional power producer is calculated using Monte Carlo simulation (IPTO, 2015; HEDNO, 2017a). Monte Carlo is applied herein to pre-filter patterns of outages to eliminate statistically unlikely outcomes. Candidate patterns are drawn for each final pattern used while choosing the pattern closest to the expected outcome (Energy Exemplar, 2019). The FOR estimated value for each generator individually is included in ANNEX IIa. Time durations to repair planned and forced outages for thermal generation technology are explicated in Table 4.9. This analysis applies a uniform time distribution, where repair time varies homogeneously.

Table 4.9*:* Average times to repair power generators (IPTO, 2014b; HEDNO, 2017a)

Generator Type	**Mean Time** (h)	**Min Time** (h)	**Max Time** (h)
Steam Turbines	863	72	2880
Gas	452	72	1550
Diesel	198	92	285
CCGT	353	140	322

The fuel price estimates are based on the IEA's 'New Policies Scenario' in the 2018 'World Energy Outlook' (IEA, 2018). This scenario is a conservative estimate of an increase in oil prices over the course of the year. The IEA's 'Current Policies' as a more conservative projection and the 'Sustainable Policies Scenarios' as more optimistic were included in the model for pursuing alternative pathways. Furthermore, in the context of the sensitivity analysis applied, the imposition of low Sulphur consistency fuels is paired with the New Policies and Sustainable cases, which significantly affects the oil prices, as illustrated in Figure 4.7.

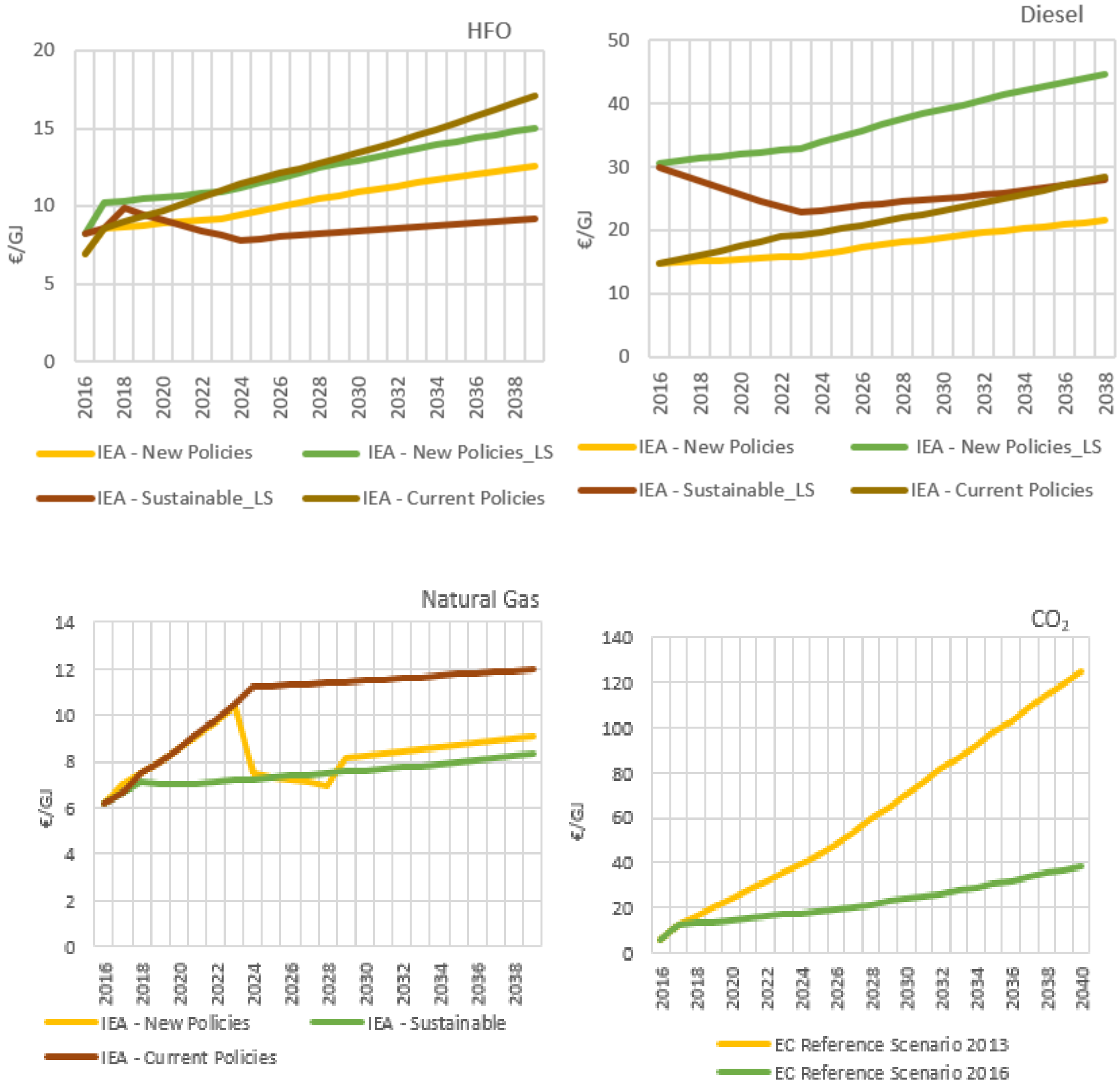


Figure 4.7: HFO, Diesel, Natural Gas, and CO_2 emissions prices projections (2020-2040)

Conventional fuel prices and taxes for the baseline year are presented in Table 4.6. Natural gas utilised to generate power is not subject to taxation. The only island assuming NG introduction is Crete due to its size and strategic position as a southern densely populated island, as per the recent agreement for the 'Eastern Mediterranean Pipeline' (DEPA Commercial S.A., 2020). Construction of

LNG storage tanks, gasification units, gas transfers, and distribution pipes are among the new infrastructure expenses associated with NG. According to the literature review, the total estimated costs for gas infrastructure on Crete are 850 million € (Katsaprakakis *et al.*, 2010, 2015). Liquefaction and transportation expenses have also been included, estimated at 2.84 €/GJ and 1.89 €/GJ (Jefferies LCC, 2013).

Table 4.6: Conventional fuel prices and taxes (2016) (Hellenic Republic - Ministry of Finance, 2010; U.S. Energy Information Administration, 2016b; Index Mundi, 2018; YCHARTS, 2018)

Cost Item	Unit	Natural Gas	HFO	Diesel
Price	€/GJ	5.5	6.6	14
Tax		0	0.4	9.7

Emissions production per thermal energy unit by conventional fuels (kg/GJ) are indicated in Table 4.7. Emphasis is placed on CO_2 and particulate matter emissions, herein represented by the severe pollutant gases of SO_2 and NO_x, closely monitored by the European Union, tracking their elimination from the EU electricity generation mix part of EN09 emissions (European Environment Agency, 2013). The 'Emissions Trading System (ETS)' mechanism adds carbon costs to traditional electricity generation (Hellenic Republic - Ministry of the Environment and Energy, 2014b). Two trajectories were considered assuming a moderate growth as proposed in the 2016 EU Reference Scenario (European Commission, 2016b) and a more aggressive option (Capros, 2014), reflecting the 2021 trend for a rapid increase in carbon costs.

Table 4.7: Emissions production per fuel (National Renewable Energy Laboratory, 2012; U.S. Environmental Protection Agency, 2016; IPCC, 2019a)

Emission	HFO	Diesel	NG
	(kg/GJ)		
CO_2	77.4	74.1	50.23
NO_x	0.063	0.058	0.003
SO_2	0.045	0.04	$8.59*10^{-5}$

4.4.2 Renewable electricity generation

Solar PVs, onshore and offshore wind, bioenergy in the form of biogas or biomass, geothermal, solar thermal, and hydropower (with storage, pumped and run-off-river) are all examples of renewable energy sources. RES are included in the system at no fuel cost to the user, although they do not yet add reserve capacity to the island or offer an upward spinning reserve. The installed capacity considered modelling inputs in the Greek NGS and the NIIs is indicated in Table 4.8 for 2016. RES installed between 2017 and 2019 are explicated in the model as candidate units.

Table 4.8: Installed RES capacity (2016) (HEDNO, 2017a)

Region	Solar	Wind	Hydro	Bioenergy
	Installed Capacity (MW)			
Agios Efstratios	0	0	0	0
Chios	5.17	12.545	0	0
Creta	88.82	220.8	0.3	0
Ikaria	0.4	4.3	4.15[35]	0
Karpathos-Kasos	1.16	1.41	0	0
Kos-Kalymnos	8.8	15.8	0	0
Lemnos	1.9	3.48	0	0
Lesvos	8.84	14.56	0	0

[35] Installed WPHS system but not operational until 2019.

Milos	0.1	2.1	0	0
Mykonos	1.04	1.23	0	0
Paros	4.21	13.52	0	0
Patmos	0.15	1.2	0	0
Rhodes	18.16	54.8	0	0
Samos	4.37	8.28	0	0
Serifos	0.62	0	0	0
Skyros	0.32	0	0	0
Symi	0.19	0	0	0
Syros	0.99	2.84	0	0
Thera	0.25	0	0	0
NGS	2445	1968.28	1471	57.69

PV efficiencies present seasonal correlation in the Greek islands' region, with considerable differences among the months, particularly in the Northwestern Aegean Sea and Crete (Katopodis et al., 2020). With average 'Global Horizontal Irradiance (GHI)' levels exceeding sometimes 1,900 kW/m^2 (Huld, Müller and Gambardella, 2018), one of the highest in Europe, the average generation levels fluctuate around 1,550 kWh/kW (Figure 4.8) (The World Bank, 2019b). The highest potential being recorded between April and September is affected mainly by the GHI benefiting from the increased length of the day, temperatures, clear sky and other weather conditions, as illustrated in Figure 4.9. As solar power presents lower intermittency than wind, it could replace the significant thermal generation capacity of approximately 8 GW (1 GW on the Greek islands and 7 GW in the interconnected part), especially when combined with energy storage. The limited capacity of solar projects on the Greek islands derives from the higher land footprint PV systems occupy compared to other technologies and the limited area of the Greek islands considering environmental and touristic restrictions. The current ratio, estimated to be valid until 2025, is 1 MW for 10,000 sqm (SolarPower Europe, 2019).

Wind energy is also abundant on the Greek islands, with wind speed levels ranging between 7-10 m/s while often exceeding 13 m/s (RAE, 2011), as illustrated in Figure 4.10. The estimated available wind capacity in the islanding region, including existing and offshore projects, is close to 4.6 GW, while the Greek mainland could host 7 GW, according to the NECP. Wind speeds in the Aegean Sea are also seasonal, with five-year average statistics showing higher wind potential over July and August, while the lowest is recorded during May (Figure 4.11), which has been selected as a representative month for our short-term modelling statistics. Despite the seasonal correlation, there is no clear pattern for the daily wind speed profiles compared to solar energy.

For solar and wind technologies, data is derived from the MERRA-2 dataset provided by the National Aeronautics and Space Administration (Pfenninger, S., Staffell, 2018). A fixed axis and 25° tilt are incorporated in terms of solar. The selected wind turbines concern Enercon E-66 at 1.5 MW for existing projects (pro-2016) and the Vestas V-112 at 3 MW for projects built in 2017 to reflect the technology trends and spatial limitations.

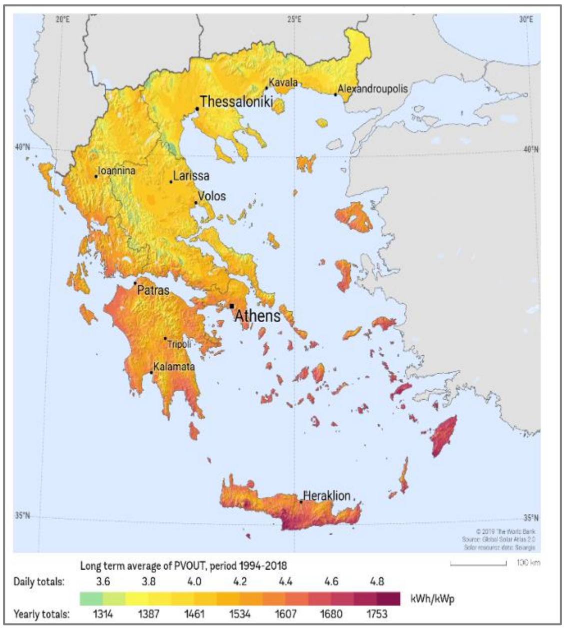


Figure 4.8: Photovoltaic power potential in Greece (The World Bank, 2019b)

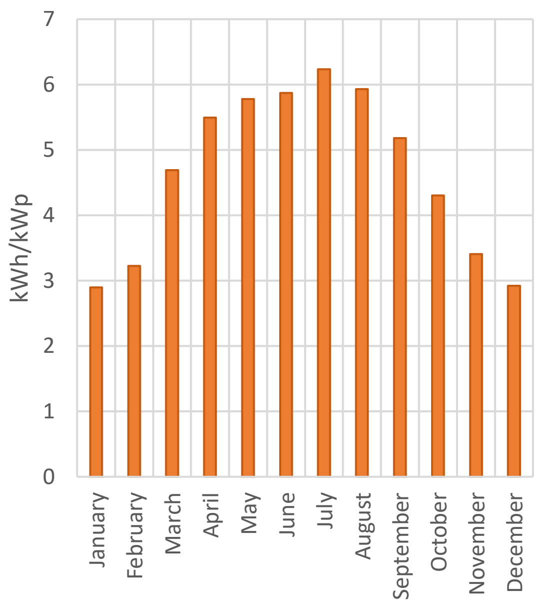


Figure 4.9: Photovoltaic daily power potential per month in the Greek islands region (2012-2016) (Pfenninger, S., Staffell, 2018)

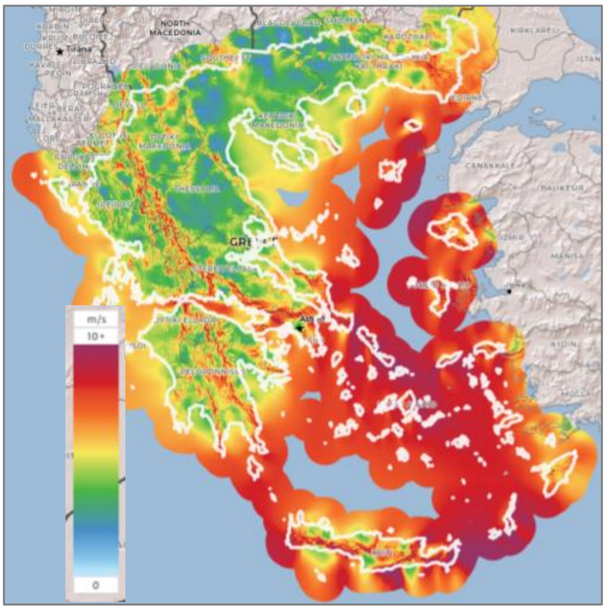


Figure 4.10: Wind potential in Greece (The World Bank, Technical University of Denmark and VORTEX, 2018)

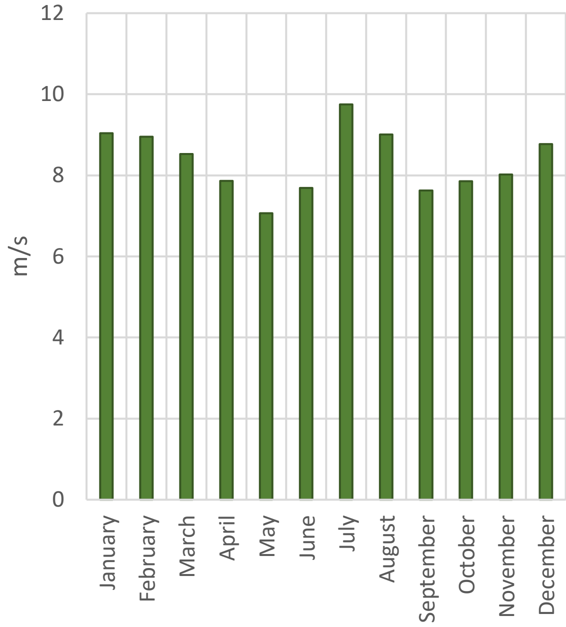


Figure 4.11: Wind speeds at 80m per month in the Greek islands region (2012-2016) (Pfenninger, S., Staffell, 2018)

Key data related to the operating features of dispatchable renewable sources such as bioenergy, geothermal and hydropower sources are derived from the literature as presented in Table 4.9. Geothermal energy will be produced on islands with a suitable geothermal field, with a total capacity of 50 MW. High enthalpy sites have been discovered in Lesvos, Milos, and Nisyros. For solar thermal, the 'Direct Irradiance At Normal Incidence (DNI)' was included, synchronised with the solar irradiation rating for PV, and integrated as a natural inflow in the PLEXOS storage model (Solar Irradiation Data, 2016). Solar thermal is found in southern areas such as Crete and Rhodes, with a maximum capacity of 180 MW.

In terms of hydro, the islands have intriguing geomorphologies that might allow for medium-scale pumped hydro storage plants, whereas Crete and Ikaria currently operate two hydro-pump systems. The reservoir and pump station sizing was performed considering 10-12 hours of storage capacity following a daily pumping cycle. The year was split into two seasons: the wet season (October-April) and the dry season (May-September), assuming a reduced daily energy release of between 25% and 35% depending on the climatic zone (Hellenic Republic - Ministry of the Environment and Energy, 2018c). Monthly constraints of binding energy for each hydro unit in the mainland were introduced in the model, representing the mean value of the annual hydro injections during the past years, excluding years with high hydro production, considered outliers. On the Greek islands, a maximum potential of 332 MW of hydro-power has been estimated, especially on large and medium-sized islands such as Crete, Rhodes, Chios, Lemnos, Ikaria, and others in smaller ones such as Leros. These islands were selected per the consideration of existing permit applications filed to RAE and the literature review (Kaldellis, 2002; Caralis, Rados and Zervos, 2010; Katsaprakakis *et al.*, 2012; Papaefthimiou, 2012). In addition to the existing pumped-storage plants on the Greek mainland, four new plants are anticipated to get constructed and operated in the upcoming years. These plants are located in Western Greece (500 MW), Peloponnese (220 MW) and Thessaly (160 MW). Smaller hydro plants (<15 MW) in the Greek Mainland could reach 600 MW, mainly in Western Greece.

Due to a lack of raw material, either in the form of urban trash or agricultural leftovers as raw-source materials, bioenergy has a limited potential on the Greek islands, estimated at less than 15 MW. New units connected with the NGS estimate a potential of 50 MW, while currently, a biogas station of 1 MW is under operation on Crete.

Table 4.9: Indicative operating parameters for RES (Katsaprakakis *et al.*, 2012; IRENA, 2013, 2015, 2017a, 2019a; Aleo Solar, 2018; Pfenninger, S., Staffell, 2018; Wind Europe, 2018; Schumacher and Weber, 2019)

Technology	**Technical Lifetime** (years)	**Capacity Factor (annual)** (%)
Wind Onshore	20	20-50
Wind Offshore	25	40-45
Solar	25	14-23
Biomass	25-30	62-87
Hydro Power	40-50	22-45

		(Pump efficiency 70%)
Geothermal	30	61-73.5
Solar Thermal	20	22-28

Renewable electricity technologies are included in the model individually, considering 690 units, except for solar projects with lower than 0.2 MW capacity, grouped at the regional level (transmission area). In the mainland, renewables are clustered per technology at the node level while excluding large hydropower plants emulated at the unit level. Maintenance and forced outages for renewable energy inserted in PLEXOS to compute reliability indices are included in Table 4.10.

Table 4.10: Outage factors for RES (Ribrant, 2006; Myhr et al., 2014; Pfaffel, Faulstich and Rohrig, 2017)

Technology	FOR (%)	Maintenance Factor (%)	Mean Time (h)	Min Time (h)	Max Time (h)
Wind	2%	3%	48	4	192
Solar	1.5%	2%	16	3	120
Solar Thermal	2.5%	3%	16	4	145
Hydro	4.9%	6.2%	64	24	342

Future renewable energy projects are taken from the application listings (RAE, 2019). Following 2025, projects' applications in NATURA 2000[36] protected sites will not be implemented across the country, assuming further strict environmental permitting criteria (Spiropoulou, Karamanis and Kehayias, 2014). Renewable energy projects in Greece follow a lengthy procedure of issuing the final connection permits, which usually last 2-5 years for solar PV and more than five years for the rest of the technologies envisaged in the modelling assumptions. Projects that have already applied for an 'Energy Producer Certificate' are usually insufficient in the Interconnected or the Autonomous pathway envisaging large-

[36] https://ec.europa.eu/environment/nature/natura2000/data/index_en.htm

scale BESS deployment when large quantities of renewable energy generation on islands become technically viable and economically feasible. Additional candidate capacity will be added to the model in these conditions to build more units to meet the demand requirements. On the other hand, unless ESS such as batteries or hydro-pump projects are deployed, integration of new RES at the autonomous state is limited by the constraint that installed RES capacity for a year (y) is less than or equal to 30% of the forecasted annual peak demand for a year (y+1) (Katsaprakakis and Christakis, 2009).

Wind offshore was treated separately from the other technologies considering a specific spatial framework, including 12 suitable areas proposed by the Greek state (Katseli, 2019). Two locations in the Aegean Sea were chosen based on strong wind speeds of >7 m/s, environmentally accessible zones, closeness to the coast, and seabed depths of 50 m. The first wind offshore project, with 498.15 MW, is located on the east side of Lemnos Island and has already acquired the energy production license. The second project under consideration for a production license from RAE is a 445 MW project located north of Agios Efstratios. Both projects are located in the North Aegean prefecture. They will use the Senvion 6.15 MW W/T type. Following an in-depth techno-economic analysis presented in Zafeiratou, Spataru and Bleischwitz (2016), opting for a common interconnection of the two projects with 500 MW DC cables is recommended. The optimisation in both investment cases in terms of sizing, siting and interconnection lead to a high investment of return factors exceeding 17%, proving that offshore wind farms could be a key decarbonisation catalyst at the regional and national level.

Build costs for various renewable energy technologies have been extrapolated at an annual level from 2020 to 2040, presented for the key milestone years in Table 4.11. They have been separated into islands and the NGS to represent economies of scale since multi-MW utility-scale projects are often found on the mainland of Greece, where costs are lower. Overall, declining costs are recorded among all the technologies, led by solar and wind offshore until 2030. The costs are stabilised or reduced at a slower pace, linked mainly to technological limits to further reduce the cost of certain materials. Existing projects are expected to continue operating after their lifetime has expired, thanks to a repowering mechanism. For those projects, a cost ceiling of 75% has been assumed, according to (IEA, 2011).

Table 4.11: Build costs for RES (IRENA, 2013, 2017b; REN21, 2016; John Hensley, 2017)

Year	Biogas	Biomass	Wind Onshore	Wind Offshore	Hydro Small	Hydro Large	Solar	Solar Therm.	Geothermal
Island (€/MW)									
(Baseline) 2016	1420	2830	1250	3300	2520	2000	1150	5000	4100
2020	1320	2800	1180	2910	2340	1840	920	4700	3760
2030	1280	2450	970	2060	2054	1600	560	4120	3110
2040	1150	2300	800	1680	1770	1450	420	3000	2760
Mainland (€/MW)									
(Baseline) 2016	1420	2830	1230	3300	2520	2000	1120	5000	4100
2020	1300	2700	1180	2910	2340	1840	875	4700	3760
2030	1250	2430	900	2060	2054	1600	490	4120	3110
2040	1120	2250	800	1680	1770	1450	360	3000	2760

Operational costs for renewables reflect the 'Levelized Cost of Energy (LCOE)'. In the Greek electricity market, they are recuperated, including a relevant premium either in the form of 'Feed-in Tariff (FIT)' for existing projects until 2016 (Zafeiratou and Spataru, 2016) or in the form of 'Feed-in Premium (FIP)' for wind and commercialised solar technologies through auction schemes assumed to last until 2030. FiT subsidised older renewable energy projects with high remunerations, while FiP aimed to reduce costs for the consumer's benefit. Following 2025, the direct participation of fully commercialised technologies in the electricity market through the Greek version of the Target Model will enable the full integration of renewables in the power system economics and facilitate border-free cross-trading across Europe (Keay, 2013). Therefore, onshore wind and solar technologies are assumed to be remunerated from the day-ahead market or bilateral corporate PPAs between producers and offtakers; meanwhile, the rest of the technologies will proceed with FiP. As presented in Figure 4.12, between 2018 and 2020, the auctions in the Greek market, combined with the high investment interest and equipment costs decline, have dropped prices regarding commercial technologies such as wind and solar. The RES generation costs show a steep reduction as of 2022, as more renewables enter the system in the post-pandemic era, which is anticipated to continue until 2040. Specific technologies such as bioenergy and wind offshore with FiT multiple times higher than the LCOE have a greater margin for reduction.

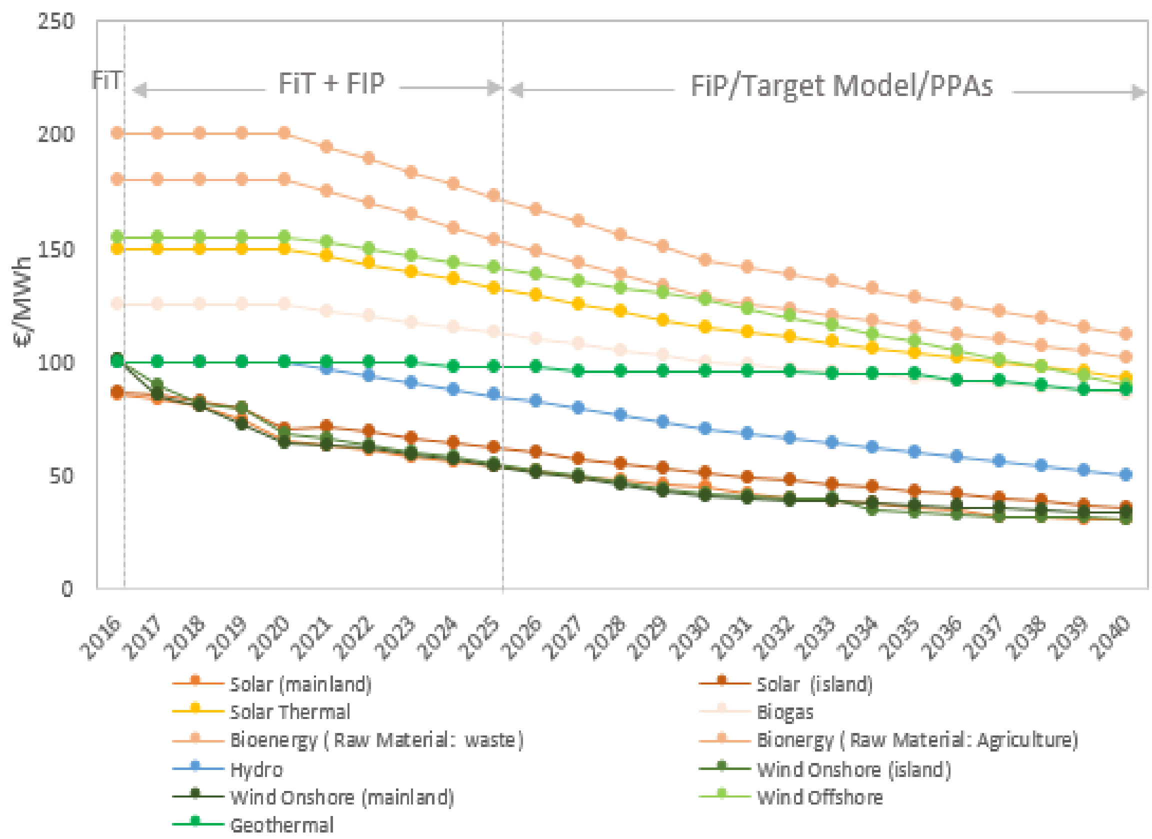


Figure 4.12: RES electricity costs in Greece (Papaefthimiou, 2012; IRENA, 2013; Hellenic Republic - Ministry of the Environment and Energy, 2014b; REN21, 2016)

4.4.3 Ancillary services

Ancillary services provided by thermal generation units have been split into three different types of reserve provision: **regulation** (frequency keeping) capability, **fast raise/lower response or spinning reserve** (for various timeframes such as 6-60 seconds or several minutes), and **non-spinning** (or replacement) reserves. Reserve provision is compensated at 10 €/MW, while real-time dispatch (€/MWh) is compensated considering the merit order of the electricity system. The VO&M costs for keeping the system in standby mode as a non-spinning reserve is included in Table 4.12. Regulation, fast response spinning and non-spinning reserves on the islands are provided by steam generators and gas turbines contributing 10% and 15% of their net capacity, respectively. More flexible units, such as 'Combined-Cycle Gas Turbines (CCGT)' and 'Internal Combustion Engines (ICE)', contribute 20% of the net capacity. Natural gas and hydropower systems provide spinning and regulation reserves on the mainland. Alongside lignite units, they also provide non-spinning capacity reserves. Part of the system's retired and commissioned capacity following 2020 is preserved as a cold reserve (spare capacity) and contributes to the replacement provision (reflecting 10-15% of the annual peak load). This usually comprises oil, lignite or gas-fired generators. In case there is no sufficient upward or downward reserve provision, the system experiences either power shortages or renewable energy power curtailments.

Table 4.12: Variable O&M reserve costs (Kumar et al., 2012; Egill Thorbergsson et al., 2013)

Generator Type	**Reserves VO&M** (€/MWh)
Steam Turbines	2
Gas Turbines	0.8
Diesel <20 MW	2.5
Diesel ≥20 MW	2.5
CCGT	1.8
Diesel (Natural Gas)	1.8
CCGT (Natural Gas)	2.5

Of particular importance is the fact that the upcoming energy transition on islands leads to low inertia, risking local grid stability. Although inverter-based renewables have not been considered a reserve provider due to their priority in dispatch and technical constraints, solar PV offers the system reactive power and voltage support through downward balancing services. Therefore 10% of each solar PV station is allocated to provide a lower spinning reserve. Hydropower stations have been modelled in a synchronous mode to provide a spinning reserve. Furthermore, bioenergy plants operate like conventional power stations and contribute to reserve provision in regulation and spinning reserve provision.

The regional risk (Eq. 4.18), which determines provision requirements for fast response and regulation reserves, has been set to the maximum among; a) 10% of the decade peak load (2020-2030, 2031-2040), which is the minimum regional provision b) a contingency generator: the largest local thermal generator or submarine cable in case of realized HV interconnections c) line risk if the region is interconnected d) regional load risk of 8-12% including a static risk estimated at 3% of the annual peak load as described in the following equation.

$$\begin{aligned} &Reserve\ Risk \\ &= Static\ Risk \\ &+ Max(Min\ Provision, Generator\ \ Contigency, Line\ Contigency, Load\ Risk) \end{aligned}$$

Eq. 4.18

Shortage of ancillary services provision is defined according to Eq. 4.19.

$$Reserve\ Shortage = Reserve\ Provision - Reserve\ Risk$$

Eq. 4.19

In parallel, a set of constraints were inserted in the model to reflect renewables intermittency, which ensures that the committed reserved capacity is always higher than a specific forecasting error rate (ERi), reflecting hourly RES intermittency multiplied by the forecasted hourly RES production as described in Eq. 4.20.

$$\sum_i P_{i,t}^{T} \geq ER_{R,t}^{W/T} \sum_j Q_{j,t}^{W/T} + ER_{R,t}^{PV} \sum_j Q_{j,t}^{W/T} \ ,\forall t$$

Eq. 4.20

Where:

'P' is the ancillary services provision;

'T' is the type of ancillary services: a) regulation, b) fast response, c) replacement);

'R' is the electrical region;

'Q' is the generation produced;

't' is time;

'I' is the conventional generation unit;

'j' is the renewable generation unit;

'W/T' is the wind turbine;

'PV' is the solar photovoltaic;

'ER' is a) for regulation is the error rate in terms of losing a certain percentage of the generation (regulation) unexpectedly;

b) for fast response is the forecasting error rate in terms of fast upwards or downwards variability of the generator (fast response);

c) for replacement is the forecasting generation error rate (replacement capacity).

The interconnection capacities are considered further reserves for the islands. In the Interconnection pathway, the capacity reserve sharing option has been activated amongst the interconnected regions, enabling to share reserves to contribute to ancillary services. At the same time, the N-1 criterion becomes the threshold to secure that local thermal capacity is equal to 90% or more than the maximum capacity of one of the cables, in addition to the reserves required for the demand that the interconnection cannot cover. N-1 is the rule according to which the components remaining in operation within an electrical transmission system after the incidence of a transmission failure are capable of accommodating the new operational situation without violating operational security limits (Glowaski Law Firm, 2017).

4.5 Transmission capacity

4.5.1 Modelling transmission networks

For each year, the PLEXOS model endogenously evaluates whether the planned investment in transmission lines will reduce the total costs; and if the economic benefits will overcome the annual costs associated with the investment project (Di Cosmo, Bertsch and Deane, 2016). Power flows in transmission networks are modelled using a linearised DC-OPF method, which refers to the generator dispatch and resulting AC power flows at minimum costs with respect to thermal limits on the AC transmission lines, described in Eq. 4.21. For the purposes of determining actual power flows, the linearised DC-OPF assumes that resistance is small and voltages are all 1 per unit (p.u.). However, this does not preclude the modelling of thermal line losses (Eq. 4.25) (Lin and Magnago, 2017). In contrast with a transportation model where the flow on all lines is controllable, in a DC-OPF, Kirchhoff's Voltage Law (KVL) constraints are applied; therefore, modelled flows mimic AC flows (Energy Exemplar, 2020). The mathematical formulation of DC-OPF is described below, according to Lin and Magnago (2017):

$$P_j = B_j * (\theta_b - \theta_a)$$

Eq. 4.21

Where:

'Pj' is the actual power flow on transmission line 'j' flowing from node a to node b (in MW);

'Bj' is the susceptance of line j, which in this linearisation is equal to the inverse of the reactance 'Xj p.u.' according to (Sen Gupta and Lynn, 1980)*,* $B_j = 1/X_j$*;*

'θ_a, θ_b' are the phase angles at the sending and receiving nodes, respectively.

Where:

$$X_j\ p.u. = X_j * MVA\ base/(kV_{L-L^2} * 1000)$$

Eq. 4.22

$$X_j = 2pfl$$

Eq. 4.23

Where:

$$kV_{\mathrm{L-L}} = (\sqrt{3} * \frac{kVbase}{\mathrm{MVA\ base}})$$

Eq. 4.24

Where:

'f' is the frequency;

'l' is the inductance;

Mega Volt Amber (MVA) base is 100.

$$Loss = (R_j\ p.u./\ MVA\ Base)\ X\ (Flow)^{\ 2}$$

Eq. 4.25

Where 'resistance per unit', according to (Sen Gupta and Lynn, 1980), is*:*

$$R_j\ p.u. = R_j * \ MVA\ base/(kV_{L-L^2} * 1000)$$

Eq. 4.26

Where 'resistance', according to Electronic Tutorials (2017) *is:*

$$R_j = \rho * L * 10^6/A$$

Eq. 4.27

Where:

'ρ' is resistivity (ohm * m);

'L' is the length of the cable (m);

'A' is the cross-section (mm^2).

Data related to the technical interconnections features such as cross-section, resistivity, frequency, inductance etc., for calculating the power flows of lines were extracted from Bjorlow-Larsen, (2003); ABB (2010); Stavrou (2012); CABLEL (2016); HyperPhysics (2018); Electronic Notes (2021).

4.5.2 Subsea islands interconnections

In Greece, the first island interconnections took place in the 1960s for the nearest mainland islands in the Aegean Sea, using 15 kV MV cables. Subsequently, more distant islands followed, but still within the limits of 40 km, increasing voltage to 20 kV. The interconnection of the Ionian Sea islands was identified with HV cables ranging between 66 kV and 150 kV. Moreover, Evia Island, alongside Andros and Tinos in the Cycladic region, has been interconnected with a 150 kV HV line with the mainland. In 2014, the Cycladic islands' interconnection was announced as an ongoing project expected to be completed entirely by 2024. The Cycladic islands interconnection by 2020 concerns Syros connected with the mainland and Paros electrical system. The second phase of the Cycladic interconnection included Naxos and Mykonos islands, as described below. Crete island is also undergoing its first phase of interconnection, which is expected to complete soon. Concerning the rest of the islands examined herein, they remain independent or interconnected in clusters with MV cables; however still isolated from the mainland and the national grid network.

The existing (25) MV, AC subsea cables and the recently installed HV interconnections were introduced in the model alongside their techno-economic characteristics (capacity, reactance, resistance, installation and maintenance costs). For the sake of this research, as the completion of the interconnection of the Cycladic islands is currently in execution, we considered this project appropriate to be examined for transmission extensions. Table 4.13 indicates the main operational features used for modelling the existing MV submarine interconnections, including the calculation of operating limits and losses described in the previous section. The MV cables are imposed to a FOR described in Eq. 4.28 and a fixed maintenance rate per annum of 1.8% (Woodford, 2011; Nugraha, Silalahi and Sinisuka, 2016). The average time to repair fluctuates between 96 and 1,200 hours, with an average time of 620 hours (Hodge, 2005; Nugraha, Silalahi and Sinisuka, 2016).

$$FOR_{Cables} = 0.19\% * l$$

Eq. 4.28

Where 'l' is the length of the cable.

Table 4.13: Existing MV interconnections' techno-economic features (Woodford, 2011; Stavrou, 2012)

Region	**Transmission Line**	**Number**	**Max Flow**	**Resistance**	**Reactance**	**Length**	**Commission**	**Decommission**	**FO&M per cable**
			(MVA)	**(per unit)**		**(km)**	**(year)**	**(year)**	**(k€/year)**
Cyclades	Folegandros-Sikinos	2	5	5.15E-02	1.89E-03	18..5	1989	>2040	88.8
	Koufonisi-Schoinousa	1	6.6	7.05E-02	3.48E-04	9..2	1983	>2040	44.16
	Naxos-Irakleia	1	6.6	6.75E-02	3.19E-04	8..8	1997	>2040	42.24
	Naxos-Koufonisi	1	6.6	4.75E-02	1.58E-04	6..2	1983	>2040	29.76
	Paros-Antiparos	4	7	1.59E-02	1.66E-05	1.9	1973	>2040	9.12
	Paros-Ios (existisng)	2	12.1	7.63E-02	3.91E-03	27	2000	>2040	108.0
	Paros-Naxos (old) I	5	10.5	2.09E-02	3.10E-04	7.5	1973	2022	36.0
	Paros-Naxos (old) II	1	10.5	1.98E-02	2.78E-04	7.1	1992	2022	34.08
	Paros-Naxos (old) III	1	12.1	2.12E-02	3.02E-04	7.5	2004	>2040	30.0
	Schoinousa-Irakleia	1	6.6	3.53E-02	8.71E-05	4.6	1983	>2040	22.08
	Sikinos-Ios	2	5	1.23E-01	4.36E-04	10.3	1989	>2040	49.44

	Thera-Therasia	2	6	2.15E-02	3.23E-05	2.8	1980	>2040	13.44
Dodecanese	Gyali-Nisyros	2	6	5.52E-02	2.13E-04	7.2	1988	>2040	34.56
	Kalymnos-Leros	2	10.4	1.11E-02	8.83E-05	4	1974	>2040	19.20
	Kalymnos-Telendos	2	5	1.31E-02	4.98E-06	1.1	1980	>2040	5.28
	Karpathos-Kasos	2	5	1.81E-01	9.51E-04	15.2	1984	2032	72.96
	Kos-Gyali	2	6.6	7.97E-02	4.45E-04	10.4	1988	>2040	49.92
	Kos-Kalymnos I	1	10.4	3.53E-02	8.90E-04	12.7	1973	>2040	60.96
	Kos-Kalymnos II	1	12	4.29E-02	1.24E-03	15.2	2008	>2040	60.80
	Kos-Pserimos	2	5	5.13E-02	7.61E-05	4.3	1980	>2040	20.64
	Leros-Leipsi	2	5	1.16E-01	3.87E-04	9.7	1990	>2040	46.56
	Nisyros-Telos	2	6.6	1.23E-01	1.05E-03	16	1989	2030	76.80
	Rhodes-Chalki	2	6.6	1.13E-01	8.89E-04	14.7	1989	>2040	70.56
North Aegean	Chios-Oinouses	4	7	3.09E-02	6.29E-05	3.7	1973	>2040	17.76
	Chios-Psara	2	6.6	1.58E-01	1.75E-03	20.6	1992	>2040	98.88
	Fourni-Thymaina	2	5	2.74E-02	2.18E-05	2.3	1980	>2040	11.04
	Samos-Fourni	2	5	1.01E-01	2.97E-04	8.5	1984	>2040	40.8

HV submarine grid extensions have been planned throughout the upcoming decades to facilitate a regional super-grid among the Greek islands and the mainland, potentially expanding into third countries to address the security of supply issues while also reducing generation costs. Specifically, the Greek islands' transmission extensions plans include 42 out of the 47 non-interconnected islands, representing 98.7% of the total population on the non-interconnected islands and 97.2% of the total electricity generation produced. Due to their small size and distance from the shore, the remaining islands are assumed to continue autonomous, supported by ESS. The selection was based on the main principle of being eligible to become interconnected with neighbouring islands and eventually with the Greek mainland as presented initially in the 'Public Strategic Plan' published in 2004, as well as the 'Ten-year Transmission Extension Plan' published by the IPTO annually following an evaluation analysis (National Technical University of Athens, 2008; IPTO, 2014b, 2021b).

Crete will be imposed to thermal power generation restrictions as of 2022, while as of 2030, the same restrictions will apply to all islands irrespectively of their size; yet, the main part of the Greek islands' interconnection project has been scheduled to be completed by 2030 indicated in Table 4.13. The interconnections will allow local thermal power plants to decommission while encouraging renewable energy development. Furthermore, they will support the islands' systems with imports from the mainland when local generation is not sufficient. The technical description of the upcoming projects is presented hereunder, depicted in Figure 4.13. Interconnections have been included in the model as 'candidate lines', while certain assumptions underpin the techno-economic features. Furthermore, specific projects are subject to sensitivity analysis and variations.

- **Cycladic Islands (A)** - Phase I completed in 2018 includes the AC, 150 kV, 200 MVA, interconnection of Syros with the Greek Mainland in the area of Lavrio in Central Greece and the AC interconnection of Syros with Paros, Mykonos islands of 140 MVA capacity. Additionally, the interconnection of Mykonos with Tinos Island of 200 MVA capacity is included. Phase II expands the cable to Naxos and Mykonos islands (140 MVA), formulating a loop among Syros, Paros, Naxos, and Mykonos to meet the N-1 criterion in 2020. Phase

III (2024) will incorporate a second cable from Lavrio to Syros to allow higher RES exportation (Papadopoulos and Papageorgiou, 2004; IPTO, 2014a; Zafeiratou and Spataru, 2016).

- **Cycladic Islands (B) –** The next phase of the Cycladic islands interconnection concerns a loop connecting the western part of Cyclades (Milos, Serifos and Folegandros) as well as the interconnection of Thera Island (Santorini) with 140 MVA, 150 kV cabling systems. Firstly, Folegandros Island (interconnected with Paros) will be linked to Milos and Milos to Serifos. The governmental proposal includes a separate interconnection from Lavrio (Mainland) to Serifos, assessed hereunder. Also, the expansion from Folegandros to Thera and then to Naxos is anticipated to be implemented by 2024 (IPTO, 2021b).
- **Crete Island** - Phase I was completed in 2021. The interconnection aims to reduce significantly local thermal power generation in Crete through its connection (Chania area) with Peloponnese in the Mainland via AC 2*150 kV, 200 MVA cables. Phase II is estimated to be commissioned in 2024 (first cable immersion in 2022, second in 2024). It proposes the interconnection of the Linoperamata area in Crete with Attica (DC bipolar links, 2*500 MW). This second cable will progressively eliminate the local oil-fired generation and concurrently facilitate the export of RES generation surplus installed on the island to the continental grid (Kabouris, 2016; Zafeiratou and Spataru, 2018). Further to the proposed plan by the IPTO, a 500 MW line is added in 2032 between Crete and Central Greece to enhance the system's reliability following the interconnection of Crete with the Dodecanese islands. In the context of the sensitivity analysis applied, the option to downsize DC cables capacity to 350 MW instead of 500 MW according to the initial foreseen plan is investigated herein as initially envisaged by Kabouris (2016).
- **North Aegean Islands** - Originally, the scheduled year for the North Aegean Islands interconnection was 2030. Nevertheless, the project will have to anticipate its implementation to ensure supply security due to the horizontal local power generation restrictions to be imposed as of 2030. During Phase I, the interconnection between Lesvos and Chios islands and between Chios and the continental National Grid System via Evia island with DC 2*350 MW

cables is assumed to occur in 2027. Chios and Lesvos will be interconnected with a double circuit DC 2*250 MW. Phase II includes expanding the interconnection from Chios to Ikaria and Ikaria to Samos islands through two AC 140 MVA cables by 2028. Phase III proposes the interconnection of Lemnos island to Lesvos via an intermediate substation in Agios Efstratios (AC 140 MVA). Further on, Lemnos will be connected to Northern Greece to the area of Philippi through a 2*250 MW DC cable by the beginning of 2029 (National Technical University of Athens, 2008; IPTO, 2020b).

- **Dodecanese Islands** - Phase I (2028) proposes Rhodes' interconnection with the Symi and Kos-Kalymnos power system via Telos and Nisyros with 280 MVA cables or 360 MVA in case a more ambitious RES plan is applied. Furthermore, Patmos island's interconnection with Kalymnos and Samos ensures that the Dodecanese islands are simultaneously interconnected with the Northern Aegean Sea region. Following these cables' immersion, the Rhodes power station will supply power to the Kos-Kalymnos region and Patmos. Besides, Nisyros geothermal power station (≈40 MW) could cover part of the islands' baseload power requirements. Phase II (2029) proposes the interconnection of the Dodecanese Islands with Crete. The interconnection will operate with two AC cables of 280/360 MVA capacity each. A third cable's immersion might be required later, investigated herein. This project's interconnection route will include the following destinations: Crete, Kasos, Karpathos and Rhodes. The interconnection will also include a medium voltage overhead grid between two substations in Crete (Vai, Atherinolakos) of a total length of 30 km. The option to directly interconnect Kos with the Mainland through bipolar DC links, 2*450 MW, is identified as an alternative to the Crete - Dodecanese interconnection (National Technical University of Athens, 2008; IPTO, 2021b).
- **Skyros Interconnection** with Evia Island, already interconnected with the Greek mainland, will be implemented with DC 3 *250 MW cables through a 154 km length connection, including submarine and underground cables, to transfer energy from large scale licensed wind projects, ready to be implemented in the area of Skyros (HEDNO, 2010).

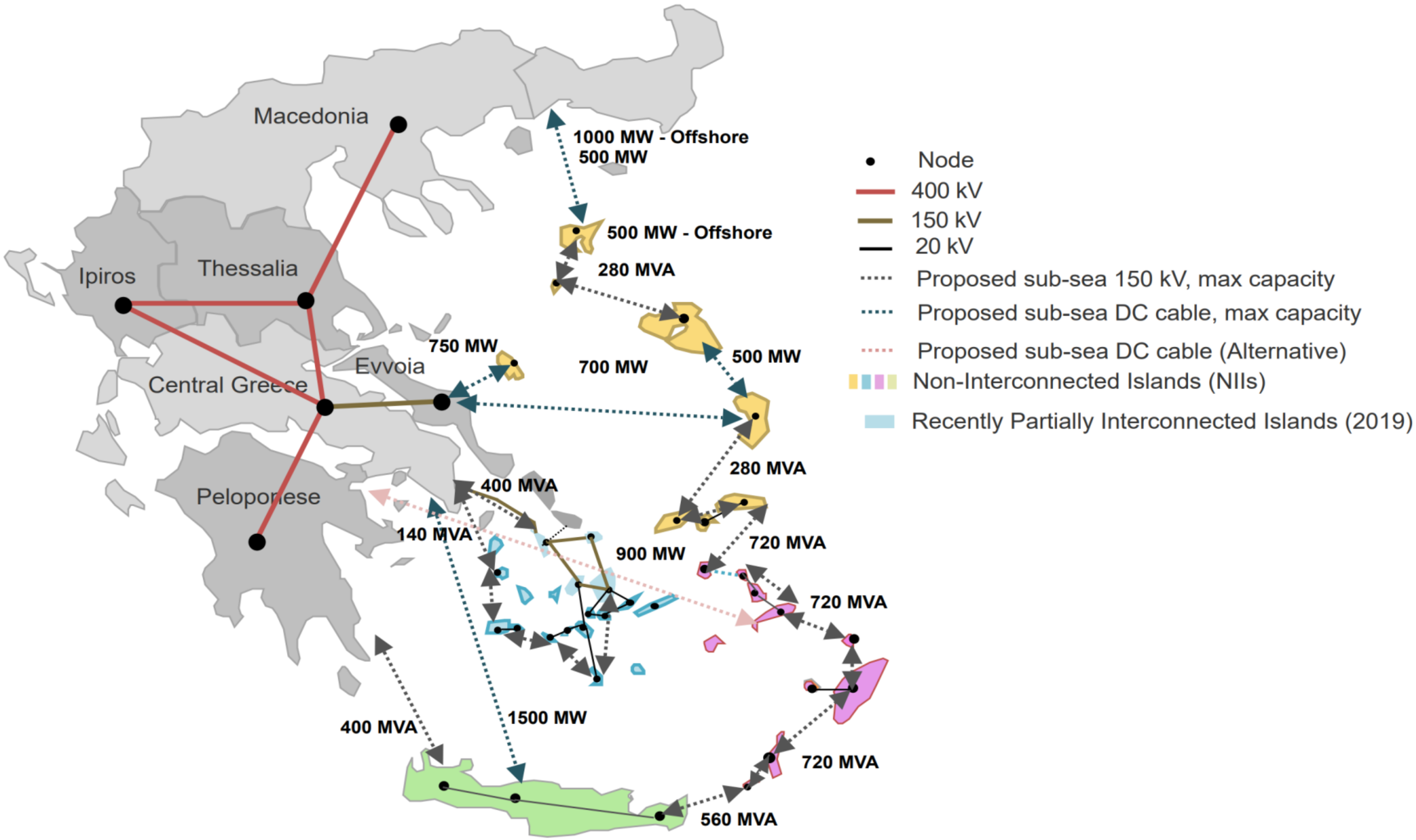


Figure 4.13: Future interconnections Greeks islands map

Table 4.14: Future HV interconnections' techno-economic features (National Technical University of Athens, 2008; Papadopoulos and Papathanassiou, 2010; IPTO, 2014a, 2020a, 2021b)

Region	**Transmission Line**	**Current**	**Number**	**Max Flow**	**Resistance**	**Reactance**	**Length**	**Commission**	**FO&M per cable**	**Build Cost per cable**
				(MVA)[37]	**(per unit)**		**(km)**	**(year)**	**(k€/year)**	**(k€)**
Cycladic Islands Interconnection	Folegandros - Milos	AC	1	140	2.65E-02	4.80E-02	40	2023	171	57,000
	Milos - Serifos	AC	1	140	*3.45E-02*	*8.12E-02*	52	2023	195	65,000
	Serifos - Lavrio	AC	1	200	*4.55E-02*	*13.88E-02*	68.5	2023	202	135,000
	Naxos - Mykonos	AC	1	140	2.65E-02	4.80E-02	40	2020	102.6	34,200
	Naxos -Thera	AC	1	140	4.31E-02	1.27E-01	65	2024	285	95,000
	Paros - Naxos	AC	1	140	5.04E-03	1.73E-03	7,6	2020	32.52	10,840
	Syros - Lavrio	AC	2	200	4.51E-02	3.94E-01	108	2018/2024	345	115,000
	Syros - Mykonos	AC	1	140	2.32E-02	3.68E-02	35	2020	91.5	30,500
	Syros - Paros	AC	1	140	3.05E-02	6.35E-02	46	2022	117	39,000
	Thera - Folegandros	AC	1	140	3.71E-02	9.42E-02	56	2024	201	67,000
Crete Interconnection	Crete West - Peloponnese	AC	2	200	5.51E-02	5.89E-01	135	2021	492	164,000
	(Crete Central - Central Greece)	DC	2	350/500	5.48E-02	0	328	2022/2024	1,095	365,000 / 510,000
	Crete Central - Central Greece	DC	1	500	5.48E-02	0	328	2032	1,530	510,000
North Aegean	Aliveri - Chios	DC	2	350	2.67E-02	0.00E+00	160	2027	532.5	167,500
	Agios Efstratios - Lemnos	AC	2	140	2.65E-02	4.80E-02	40	2028	96	32,000

[37] For DC cables MVA values correspond to MW as a purely resistive load.

	Chios-Ikaria	AC	2	140	4.59E-02	4.09E-01	110	2028	242.1	80,700
	Chios-Lesvos	DC	2	250	1.50E-02	0.00E+00	90	2027	383.4	127,800
	Ikaria-Samos	AC	2	140	5.30E-02	1.92E-01	80	2028	303	101,000
	Lemnos-Philippi	DC	2	250	2.75E-02	0.00E+00	165	2028	216	72,000
	Lesvos-Agios Efstratios	AC	2	140	3.34E-02	2.16E-01	80	2028	180	60,000
	Agios Efstratios-Lemnos	AC	2	140	2.65E-02	4.80E-02	40	2028	96	32,000
Dodecanese Islands Interconnection	Kalymnos-Patmos	AC	2	280/360	3.38E-02	7.81E-02	51	2029	171	57,000 /68,000
	Karpathos-Rhodes	AC	2	280/360	3.55E-02	2.44E-01	85	2028	245.7	81,900/ 91,500
	Kasos-Karpathos	AC	2	280/360	3.13E-02	1.90E-01	75	2028	130.2	43,400/ 54,000
	Kos-Kalymnos	AC	2	280/360	1.01E-02	6.94E-03	15,2	2028	78	26,000/ 32,000
	Nisyros-Kos	AC	2	280/360	1.66E-02	1.88E-02	25	2028	75	25,000/ 33,500
	Patmos-Samos	AC	2	280/360	3.84E-02	1.01E-01	58	2029	216	72,000/ 84,000
	Rhodes-Symi	AC	2	280/360	2.72E-02	5.05E-02	41	2029	105	35,000/ 46,000
	Rhodes-Telos	AC	2	280/360	1.66E-02	1.88E-02	25	2028	134.7	44,900/ 57,200
	Telos-Nisyros	AC	2	280/360	3.31E-02	7.51E-02	50	2028	75	25,000/ 33,000
	Kos-Mainland	DC	2	450	5.94E-02	0	356	2029	1,950	650,000
	Crete-Kasos	AC	2	280	2.92E-02	1.66E-01	70	2029	2007.3	69,100

Skyros	Skyros Interconnection – Evia Island	DC	3	250	2.57E-02	0	154	2030	275.25	91,750
Offshore	Offshore line Lemnos-North Greece	DC	2	500	1.82E-02	0	109	2032	828	276,000
	Lemnos Agios Efstratios	AC	1	500	6.68E-03	0	40	2034	255	85,000

According to Eq. 4.28 (Woodford, 2011; Nugraha, Silalahi and Sinisuka, 2016), for new HV interconnections, forced outages in cables are likewise subjected to their length. A 0.4% risk factor is added for DC cables due to the AC/DC converter (Woodford, 2011). The maintenance rate per annum is 1.64% for cables less than 100 km and 2.33% for longer cables. The time to repair fluctuates between 168 and 1,448 hours, with an average time of 840 hours (Hodge, 2005; Nugraha, Silalahi and Sinisuka, 2016).

4.6 Battery energy storage systems (BESS)

4.6.1 BESS technology and operations

Utility-scale energy storage is one of the technology choices that can support power system flexibility while enhancing a renewable-based operation system on the Greek islands. Although several ESS could demonstrate their applicability in remote areas, the optimum technologies for islands depend on the power system configuration, available resources, and geomorphology. The storage technologies proposed so far involved solar thermal and hydropower solutions at the scale of increasing flexibility for several islands. These technologies depend on climate conditions and the abundance of water resources. Herein, electrochemical storage in the form of BESS has been considered for large-scale deployment across the islands. Other suitable technologies could be CAES and FCH, not considered in the present analysis due to technical, market and environmental limitations but could justify reasons for future research.

During the last years, most market growth has been noticed in Lithium-ion or (Li-ion) batteries, representing over 90% of the total installed capacity for large-scale battery storage (IEA, 2017). They have the highest charge and discharge efficiency of up to 95%. Besides, Li-ion batteries have high energy and power density and a long-life span while considered safe and eco-friendly. Their disadvantages can be summarised around their degradation at high voltages and high temperatures, recorded on the Greek islands over the summer months. Furthermore, they cannot charge in freezing temperatures and need a protection circuit to prevent thermal runway if stressed (Asian Development Bank, 2018). We considered Li-phosphate batteries LiFePO4, which offer good electrochemical performance with low resistance in the current analysis. The key benefits are high current rating and long cycle life, besides good thermal stability, enhanced safety and tolerance if mistreated (Egill Thorbergsson *et al.*, 2013; Battery University, 2021).

Despite its relatively high upfront cost, Li-ion BESS technology could be demonstrated in universal applications while showing optimistic trends for cost reduction (Goldie-Scot, 2019). The factors affecting batteries' feasibility are the network reinforcement, cost to connect BESS to the grid, and a favourable market supported by a policy framework, where batteries will be compensated for providing ancillary services, reserve capacities and power supply to back the economic viability of such projects.

The principal use of batteries in the model built on PLEXOS will be an electric power supply with bulk energy storage coupled mainly with wind energy and solar in complementarity. In this role, the batteries will be used for power transfer (under a contract for difference) and power capacity reinforcement, allowing the island to operate autonomously with flexibility and enhanced resilience. Most islands will rely exclusively on intermittent renewables and energy storage systems and only limited thermal capacity will remain as a backup to support the system. The storage system will be owned, operated, and maintained by a third party that provides balancing services according to a contractual arrangement, committing to a minimum degree of plant availability (Asian Development Bank, 2018).

BESS will provide power to supply peak demand. However, they will likewise serve as a baseload, especially as of 2030 when all thermal power generators shut down in relation to each island's interconnectivity. BESS will support peak shaving, which refers to levelling out electricity and valley-filling peaks. They can reduce renewable curtailment, provide frequency regulation, flexible ramping, black start services, transmission and distribution congestion relief, energy shifting and capacity investment deferral (IRENA, 2017b). BESS will additionally support the power system supply to meet demand without an expensive ramp-up of inefficient peaking generators such as gas turbines and gensets. Besides, BESS offer black start services used to re-energise the transmission system and provide start-up power to generators that cannot self-start, which diesel generators traditionally provide (AESO, 2016). In the long run, peak shaving provides transmission upgrade deferral involving delaying utility investments in transmission system upgrades (submarine, overhead and underground) or even avoiding such investments entirely. Nonetheless, the model does not consider distribution cables; therefore, upgrade deferral and voltage support at that level is not investigated hereunder.

Multiple services provisions are indicated as the main path to recording positive economic return for investments on BESS operating in the ancillary services market (A. Stephan, B. Battke, M. Beuse, J. Clausdeinken, 2016). In this respect, BESS offer ancillary services by allocating 15% of its capacity to each of these services, namely spinning, non-spinning and regulation reserves. BESS will generate revenues assuming standard capacity payment at 10.5 €/MW (LAZARD, 2018; RAE, 2018). Likewise, real-time ancillary services will be reimbursed at wholesale prices (€/MWh).

4.6.2 BESS sizing

The technical lifetime of the lithium BESS was considered 12 years according to Asian Development Bank (2018), and their economic life is ten (10) years. To avoid continuous full depths of discharges that could limit the battery's lifetime, a min and max State of Charge (SoC) was considered according to Table *4.15*. Also, the LiFePO4 capacity degradation per cycle and the charging and discharging efficiencies are presented. Batteries have to deliver voltage support within seconds, considering the available ramp-up ranges between 5 MW/min and 30 MW/min, depending upon the size of the storage system. Therefore, the maintenance of the BESS is anticipated to get aligned with the explicated assumptions of statistics presented in Table *4.16* (Asian Development Bank, 2018). As min, max and mean repair times were not available in the literature, they were aligned with the time to repair other renewable technologies.

Table 4.15: Technical specifications of BESS (Egill Thorbergsson et al., 2013; Sufyan et al., 2019)

Initial SoC (%)	**Min SoC (%)**	**Max SoC (%)**	**Charging & Discharging efficiency (%) ($Eff_{c/d}$)**	**Capacity degradation per cycle (%)**
60	20	97	90	0.01

Table 4.16: Reliability indicators for BESS

Maintenance rate (%)	**FOR (%)**	**Mean time to repair (h)**	**Min time to repair (h)**	**Max time to repair (h)**
2	3	48	4	192

The BESS sizing was calculated based on three principles:

I. **The BESS should cover 90% of the annual peak demand (MW),** through the projection horizon of 2020-2040 in each region, after losses, due to charging/discharging efficiency, assuming 97% Max SoC, presented in Eq. 4.29. This was calculated by building the normal distribution probabilities of the hourly load for all regions (the example of Crete Island is displayed in Figure 4.14). The hypothesis that no other intermittent or dispatchable capacity will meet the peak demand was considered to ensure that the island will not suffer from severe unserved demand incidents.

$$P_{inv,Load} = \frac{90\% * Peak\ Demand_{y=(2020-2040)}}{Eff_d}$$

Eq. 4.29

II. **<u>To absorb the maximum residual generation of wind energy capacity installed on the island (MW).</u>** The batteries and the inverter's design are based on their electricity distribution deviations (surpluses or deficits) (Eq. 4.30). The hourly time duration of net power demand ($P_{net} = P_{inv\ Load} - P_{inv\ RES}$) is utilised to calculate the probability distribution as illustrated in Figure 4.15, which gives the size and frequency occurrence of power discrepancies. The individual areas of electricity divergences are defined by the time duration of net power demand and their respective durations. The positive deviations correspond to energy deficits covered by controlled production units, while negative deviations represent the excess of RES energy stored or discarded.

$$P_{inv,RES} = -\frac{MaxRES\ Residual_{y=(2020-2040)}}{Eff_c}$$

Eq. 4.30

Where: MaxRES Residual= Min $P_{net} = P_{Load} - P_{RES} \leq 0$

The final design of the system in peak capacity load (MW) is performed based on the maximum of $P_{inv,\ Load}$ and $P_{inv,\ RES}$ where usually the maximum is the $P_{inv,Load}$ since the capacity of RES is calculated on the basis of the max peak load of the year.

III. **<u>The BESS should be able to provide an undisruptive power supply to the system covering 90% of the maximum demand recorded on the island between 2020 and 2040.</u>** The model's hourly power supply was considered while deducting the forecasted RES generation. Sequential values of 'Demand - RES supply ≥ 0' were included to build the normal load distribution of 'Max Energy Demand' according to Figure 4.16.

$$P_{Storage} = \frac{90\% * \sum_{i=1}^{8760} Max\ Energy\ Demand\ _{y=(2020-2040)}}{Eff_d * (SoC_{MAX} - SoC_{MIN})}$$

Eq. 4.31

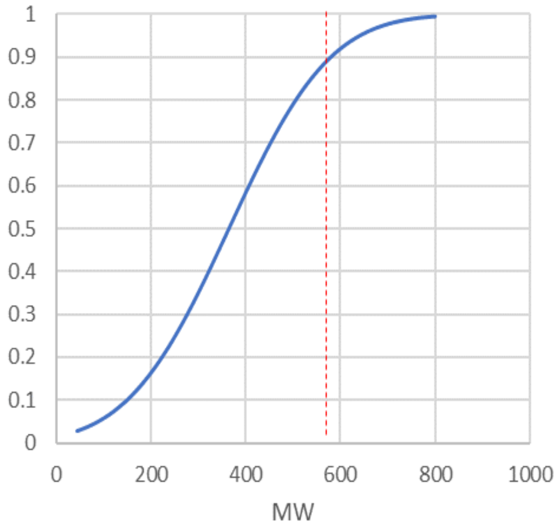


Figure 4.14: Probability function of peak demand for 2040, the example of Crete Island

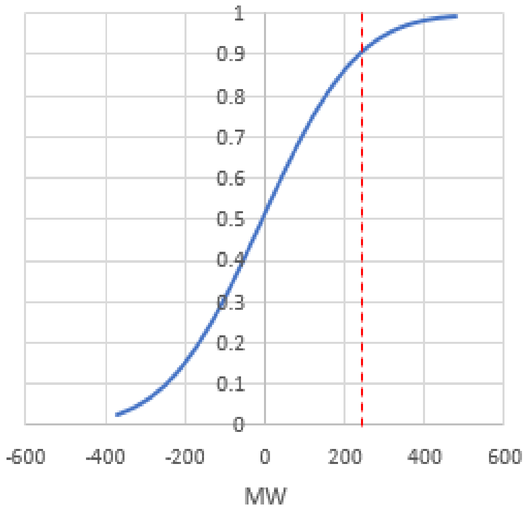


Figure 4.15: Probability function of net hourly demand for 2040, the example of Crete Island

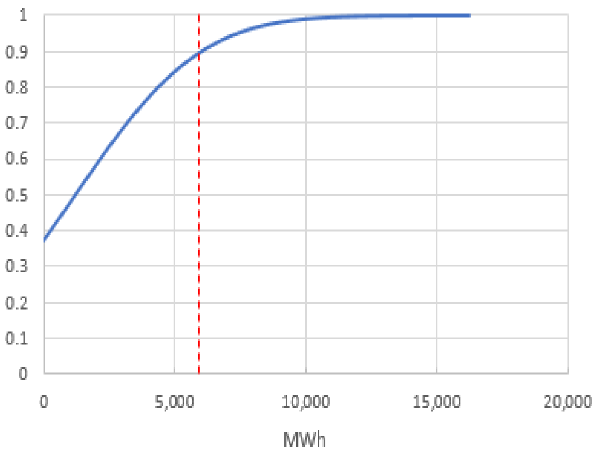


Figure 4.16: Probability function of net cumulative hourly demand for 2040, the example of Crete Island

The hybrid (BESS and wind) system's sizing was designed for every AES according to the forecasted annual demand, as presented in Table 4.17. Although it is not always the cost-optimal option for systems consisting of more than one island, deploying multiple smaller BESS units was deemed a more realistic approach with higher modelling flexibility. No pairing with specific wind capacity is considered if the BESS is deployed under the interconnection scenario as sufficient wind capacity is built. PLEXOS additionally has the flexibility to deploy along with the projection horizon units of smaller or larger capacity (within the available range provided) while respecting the requirements of the systems and the cost-optimisation approach. In the mainland, BESS of 2 GW / 8 GWh capacity split equally among the nodes was considered to be built by 2040, inspired by the Hellenic Republic - Ministry of the Environment and Energy (2019a) and Biskas (2021)

Table 4.17: Input capacity and max power of BESS per unit and wind farm capacity for the BAU Scenario[38]

Region	Node (island)	Capacity	Max Power	Storage Duration	Wind Capacity
		(MWh)	(MW)	(hours)	(MW)
Chios	Chios	880	88	10	105
Crete	Crete Central	2000	200	10	250
	Crete East	2000	200	10	250
	Crete West	2000	200	10	250
Ikaria	Ikaria	70	10	7	5
Kos-Kalymnos	Kalymnos	400	40	10	60
	Kos	1000	100	10	130
Karpathos	Karpathos	70	17,5	4	16
Lemnos	Lemnos	70	10	7	15
Lesvos	Lesvos	500	100	5	135
Milos	Milos	100	25	4	30
Mykonos	Mykonos	150	50	3	51
Patmos	Patmos	140	14	10	9
Paros	Folegandros	20	5	4	4
	Naxos	300	60	5	35

[38] For load demand inputs according to ISLA_EGI Low_Eff and High_Eff scenarios, the capacity and max power of the BESS were adjusted considering the respective probability functions.

	Paros	300	60	5	170
Rhodes	Rhodes	950	160	6	240
	Rhodes	950	160	6	240
Samos	Samos	360	60	6	100
Serifos	Serifos	48	8	6	5
Skyros	Skyros	10	10	1	7
Agios Efstratios	Agios Efstratios	4	0,5	8	1
Symi	Symi	130	13	10	9.5
Syros	Syros	400	40	10	53
Telos	Telos	2,88	0,8	3.6	-
Thera	Thera	240	60	4	112

The cost of BESS relies on the kW/kWh ratio[39] subject to the cost of the BESS (max energy storage capacity), the inverter (max power/load), as well as other expenses (electrical works, permitting, land use) presented in Eq. 4.32. The cost per kW is incrementing for batteries with larger storage capacity compared to those aiming to cover mainly instantaneous peak demand. The reference price of the battery cell in 2017 was 0.22 € per kWh stored and 0.7 €/kW for the inverter (Asian Development Bank, 2018; Fu *et al.*, 2018).

$$Total\ Cost\ BESS\ \left(\frac{€}{kWh}\right) = Battery\ Energy\ Cost\ \left(\frac{€}{kWh}\right) + [Inverter\ Power\ Cost\ \left(\frac{€}{kW}\right) + Other\ Expenses\left(\frac{€}{kW}\right)] * \frac{1}{Storage\ Duration(h)}$$

Eq. 4.32

Even though battery cell prices fell by 80% between 2010 and 2017, according to the International Renewable Energy Agency (IRENA) 2019 , costs are

[39] The input for PLEXOS was calculated on a (€/kW) basis by multiplying the different cost elements with the size of the BESS and dividing the total amount by the size of the inverter.

still a significant driver of techno-economic viability. The decline of current prices provides an opportunity for mainstream acceptance and commercial use of batteries on islands. Li-ion cell prices are expected to continue falling over the next few years; as manufacturing capacity ramps up due to scale-up drivers. In this analysis, the cost reduction of Li-ion batteries between 2020 and 2040 derives from the dedicated modelling study conducted by the National Renewable Energy Laboratory (US) (Cole *et al.*, 2019) and is illustrated in Figure 4.17. BESS are assumed to be installed following 2020, considering that no battery has been installed on the Greek islands by the modelling cut-off date (31/12/2019). The final costs per kW (inverter size) and per kWh (BESS size) on each island are illustrated in Figure 4.18. As an output of the sizing approach, systems with small energy capacity requirements (1- 4 hours) record lower built costs per kW as the primary catalyst in the final total cost configuration is the inverter's size. On the contrary, higher energy storage capacity systems record lower values per kWh and higher per kW due to a lower duration denominator.

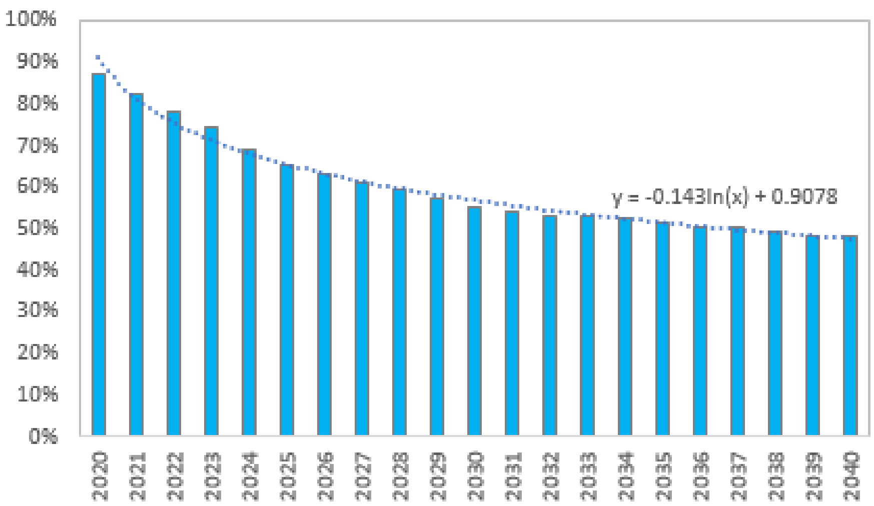


Figure 4.17: Cost reduction for battery cells as a percentage (%) of 2017 reference prices (Cole et al., 2019)

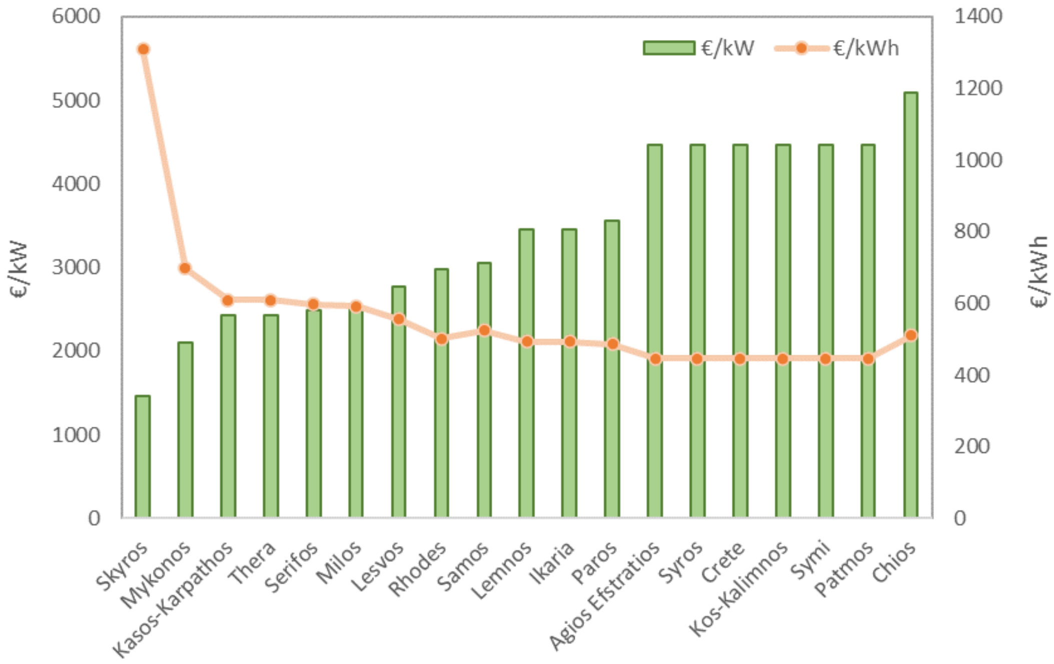


Figure 4.18: Total BESS built costs per kW and kWh for each Electrical System

4.7 Electric Vehicles (EVs)

4.7.1 EVs' deployment

In order to measure the impact of electromobility on the Greek islands, it was assumed an analogous deployment of EVs on the mainland between 2020 and 2040. A regression analysis was applied between the GDP growth rate derived from the World Bank (2019a) and new sales, as illustrated in Figure 4.19, to project future passenger vehicles registrations in Greece, while an annual scrap rate of 40,000 vehicles/year was assumed according to (Eurostat, 2017). The original 2017 figures and historical registrations for each island were provided by the Hellenic Statistical Authority (2018b). Balanced growth of passengers' cars was assumed across all islands in line with the national figures due to the absence of regional historical data.

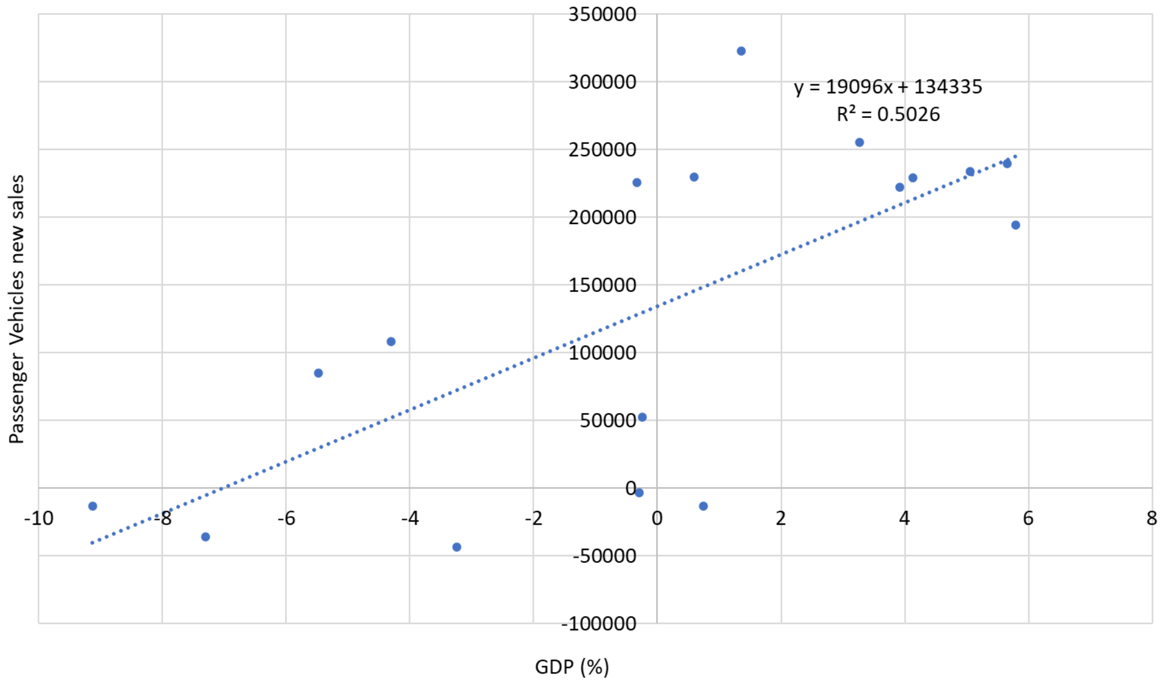


Figure 4.19: Regression analysis between new EVs registrations and GDP growth

Two EVs integration scenarios (Figure 4.20) were included as there is still uncertainty in the adoption pace in remote regions such as the Greek islands.

I. **Scenario 1 (S1)** supposes slow growth in line with the MERGE EU project figures, which were published back in 2010, assuming EV penetration of 4% in 2030 and extrapolated to almost 20% in 2040 (approximately 125 thousand EVs) (Hassett, Bower and Alexander, 2011; Hatziargyriou, 2012).

II. **Scenario 2 (S2)** supposes the achievement of the target of 24% integration of EVs into the passenger vehicles market by 2030 according to the NECP (Hellenic Republic - Ministry of the Environment and Energy, 2019a). In 2040 the figures are extrapolated to 82% share, translating into 517 thousand EVs deployed on the Greek islands.

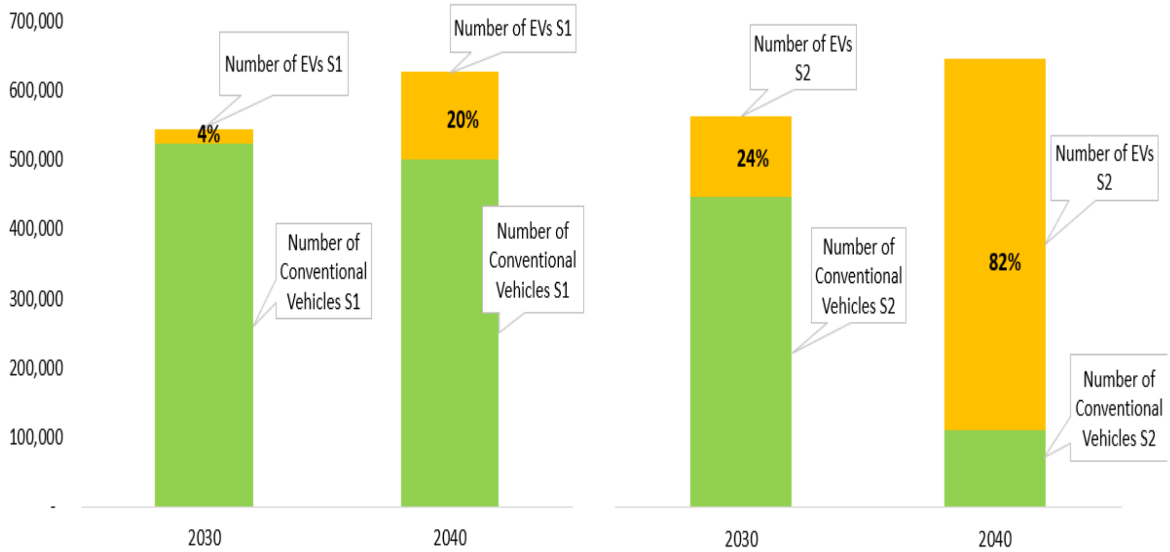


Figure 4.20: EVs in scenarios S1 & S2 vs. ICEVs

4.7.2 Modelling approach

To model EVs' impact on the Greek islands' electrical system, we encompassed 2030 and 2040 EV deployment projections in the PLEXOS electricity model. We used the three representative demand load weeks (Average, Maximum, Minimum) for the two milestone years as a chronological simulation basis. The short-term analysis utilises the results extracted from the long-term investment planning of PLEXOS; without considering additional developments to assess whether the existing energy plans could suffice additional EV charging demand on the islands. Considering long-term demand projections for the mainland, they embed forecasts for electromobility. EVs charging load was emulated using the 'Purchaser Function' in PLEXOS, which requests additional power above the native and pump/utility battery storage demand recorded (Eq. *4.33*). The model's electricity price is configured, taking into consideration the dispatch merit order, including the additional loads. No differentiation between BEVs, petrol PHEVs, and diesel PHEVs was applied as PLEXOS models the electrical load and not the vehicle type.

$$Load_{R,t} = NL_{R,t} + PL_{R,t} + BL_{R,t} + PuL_{S,R,t}$$

Eq. 4.33

Where:

'Native Load (NL)' is the actual consumers demand load per region (R) for each time unit (t);

'Pump Load (PL)' is the load requested to pump water in hydropower systems;

'Battery Load (BL)' is the charging load from utility-scale batteries;

'Purchaser Load (PuL)' is used to simulate EVs charging load for specific time zones during the day for each scenario (S).

From a computational perspective, the vehicle batteries were emulated as one single large unit per node. The actual capacity of EV batteries (BSEV) in each transmission region (R) [40] (Table 4.18) was configured by multiplying the respective number of vehicles for each Scenario (S) by the size of a typical battery (BSEVt). This corresponds to a Fiat 500e for 2030 and a Volkswagen ID.3 Pro S for 2040 (PUSHEVS, 2019; Battery University, 2020; Electric Vehicle Database, 2020), as described in Eq. 4.34. The actual load for each island (EVL) was calculated by pondering the percentage (%) of EVs charging at a specific time (t) (% EVs connected) multiplied by the capacity of the charger (Cc) (Eq. 4.35).

$$BSEV_{S,R,y} = Number\ EV_{R,y} * BSEVt_y$$

Eq. 4.34

$$EVL_{S,R,y,t} = Number\ EV_{S,R,y,t} * \left(\%\ EV\ connected_{S,y,t}\right) * \ Cc_{S,y}$$

Eq. 4.35

[40] Considering all islands interconnected under the transmission region

Table 4.18: The aggregated size of EVs batteries (BSEV)

Island	Year			
	2030		2040	
	Scenario			
	S1	S2	S1	S2
	MWh			
Chios	26.3	350.4	478.4	1980.5
Crete	302.6	4035.5	5450.3	22576.4
Ikaria	4.3	57.6	78.7	325.8
Kalymnos	10.3	137.9	188.3	779.6
Karpathos	2.9	38.8	53.0	219.4
Kos	15.3	204.6	279.3	1156.6
Lemnos	8.0	106.6	145.5	602.5
Lesvos	38.7	516.6	705.2	2919.8
Milos	2.4	32.1	43.8	181.3
Mykonos	3.8	50.9	63.4	263.7
Naxos	8.1	107.3	142.8	592.0
Paros	6.4	85.2	110.9	460.3
Patmos	2.2	29.6	40.4	167.1
Rhodes	58.7	783.6	1069.7	4429.1
Samos	16.6	221.4	302.2	1251.2
Skyros	2.0	26.1	35.6	147.7
Syros	9.9	132.7	180.5	747.5
Thera	7.4	98.6	128.0	531.1

The input assumptions used to describe the types of EVs and the charging infrastructure in the modelling exercise are included in Table 4.19. A minimum state of charge (SoC) at 20% was considered to avoid the fast ageing of batteries. Efficiency for charging and discharging (η_{cov}) has been set at 88% (Mongird *et al.*, 2019). In addition, it was assumed that 85% and 15% of usage split between EV owners on weekdays and weekends. However, the charging and discharging rates are estimated considering the average driving distance set on each island per day and the EV's average consumption, as well as the pattern to represent drivers' daily habits in terms of the hour of departure and arrival (Hellenic Statistical Authority, 2016a; Benaki, 2019).

Table 4.19: EVs modelling input assumptions (Hellenic Statistical Authority, 2013; EN+, 2017; Siemens, 2017; PUSHEVS, 2019; Battery University, 2020; Electric Vehicle Database, 2020)

Modelling Input Assumptions	**Unit**	**2030**	**2040**
Average Distance per weekday[41]	km	20-37	
Average Distance per weekend	km	16-30	
Average Consumption	kWh/100km	17,11	
BSEVt	kWh	24	77
EV range	km	150	450
Electric Charger – residential (Cc)	kW	3,7	7
Electric Charger – public (Cc)	kW	22	43

4.7.2.1 *Transport related emissions calculation*

Beyond the impact of EVs on reducing emissions from grid balancing services allowing the efficient integration of renewables, there is a strong effect in the transport sector from the replacement of conventional cars. An average BEV using electricity at a global level, considering the present global average carbon intensity (518 gCO_2eq/kWh), emits fewer carbon emissions than a global average ICE vehicle using gasoline over its life cycle (Till *et al.*, 2019). However, considering the Greek islands with high carbon intensities exceeding the 650 $kgCO_2/MWh$, the

[41] Subject to the size of the island as indicated in Hellenic Statistical Authority (2013)

shift towards transport electrification should be implemented only if combined with the parallel phase-out of thermal units.

In order to calculate the emissions avoided on each island from the transition to electric mobility (Eq. 4.36), as an alternative to EVs, we considered emissions for a new gasoline ICE vehicle purchased in 2025 to be 0.102 kg/km (JRC, 2020). Emissions are measured on a tank-to-wheel (TTW) level for an average medium-sized conventional car. TTW refers to the activities between the point at which energy is absorbed (charging point; fuel pump) and the discharge phase (driving). The vehicle's energy chain fragmentation allows direct comparison between electric and conventional refuelling options. For a BEV with no direct emissions, the upstream emissions are calculated following a power plant-to-wheel approach to remain within the scope of this research project.

$$Emissions\ Saved_{R,S,y} = EmissionsICEV_{R,y} - EmissionsEV_{R,S,y}$$

Eq. 4.36

Where:

$$Emissions\ ICEV_{R,y} = Driving\ Distance * Number\ ICEV_{R,y} * TTW$$

Eq. 4.37

$$Emissions\ EV_{R,S,y} = Driving\ Distance * Number\ EV_{R,y} * Con_y * PtW_{R,y} * \eta_{conv}^2$$

Eq. 4.38

Where:

'S' is the EVs growth scenario (S1 or S2);

'y' is the milestone year;

'R' is the region;

'TTW' is the average emissions released from ICEVs use at 0.102 kg/km;

'Con_y' is the average electricity consumed for recharging EVs;

'PtW' refers to the average CO_2 intensity per region at 2030 and 2040.

4.7.3 EVs Charging profiles

Overall, the complete set of Scheduled and Unscheduled options, as well as the Tourism scenario and V2G strategies described in the following chapters for the three representative weeks in 2030 and 2040, as illustrated in Figure 4.21, is emulated in two different states: **Autonomous Batteries without generation restrictions (AB.y.1.0.a)**[42] and **Interconnected (I.x.1.0.a).** The selection of the specific pathways caters to synergies between utility-scale storage and interconnections with EVs.

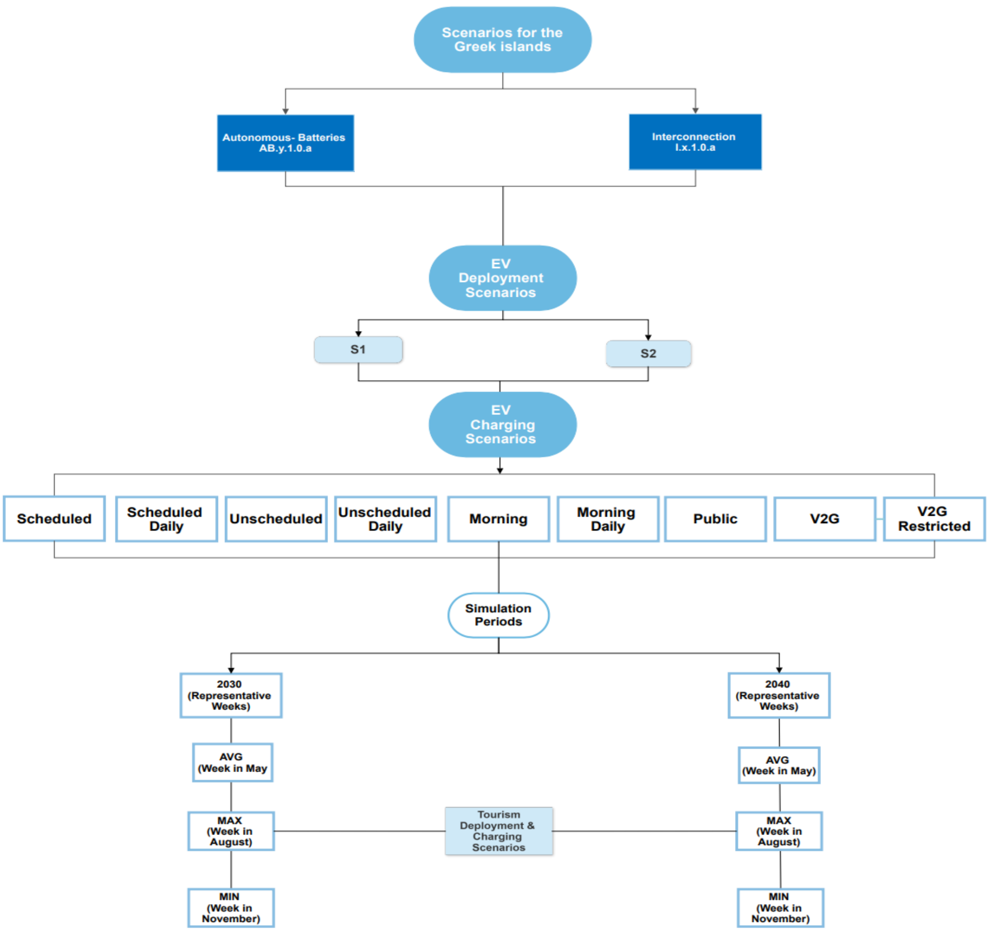


Figure 4.21: Overview of EV scenarios developed

[42] The principal autonomous pathway (AB.x.1.0.a) imposed to generation restrictions was initially selected; however, unserved demand was magnified within a range of 4-40% across all EV scenarios for 2030 and 9-51% for 2040. Therefore, a plausible Autonomous scenario such as (AB.y.1.0. a) was finally preferred without substantial power interruptions.

One of the most critical requirements in simulating EV charging and discharging is to ensure that the car has sufficient energy to complete the next day's trip. As long as this prerequisite is met, the power system operator can optimise the timing of charging/discharging, the intensity of the loads (or the generation dispatched for bidirectional uses) and the speed at which these operations are executed. The ultimate goal is to suffice to charge demand while providing ancillary services to the system. The full benefits of introducing EVs into the system are directly linked to the available energy sources to cover the demand and recharging strategies. Therefore, herein seven different charging patterns were identified. Firstly, a baseline was set with a non-EV scenario for 2030 without EV load. Each charging profile was developed to capture the impacts of controlled and unconstrained charging patterns, as described below.

I. **Controlled Scenarios** encompassing scheduled strategies, including a daily charging option, assume that users will charge their vehicles during nighttime to benefit from lower electricity tariffs. Simultaneously, utility companies using smart meters will charge to fill load valleys. This usually implies adopting smart charging techniques either through direct control of the vehicle or indirect charging by designing the vehicle to respond to price signals (Richardson, 2013).

II. **Unscheduled or Unscheduled Daily Scenarios** assume that vehicle owners will charge their cars when it is most convenient, usually during their return to home (**Public charging**) or upon their return (residential charging). Opportunistic charging behaviour assumes that vehicle owners will continuously charge their cars daily.

III. **Morning or Morning Scheduled Daily Scenarios** investigate the complementarity of EV loads incorporated in solar power by directly using its excess generation. In this scenario, the assumption is that charging occurs during morning hours, either at home or at work through public or private slow chargers.

The charging scenarios indicate the timeframes on which the electric vehicles are charged, considering statistics from the Hellenic Statistical Authority (2016a) and Benaki (2019). Through pondering the weekly driving distance per island, the specificities of the typical EV, as well as the requirement to have the car sufficiently charged early in the morning, it is proved that recharging is required to take place twice a week. Two hypothetical, convenient days, e.g., Monday or Tuesday (day 1 or 2) and Thursday or Friday (day 4 or 5) have been selected. Alternatively, an opportunistic approach assumes daily charging occurs across all categories, requesting lower demand loads. This assumption configures the factor (t) in Eq. 4.35.

The departure and arrival time selection among the scenarios was based on information about the working hours at the national level, relevant peculiarities existing on islands primarily related to the tourism industry, and data from the SHFB survey (Hellenic Statistical Authority, 2016b). Among other information, the survey specified the time of leaving and returning home and the share of the population that remains at home. Thus, the data show that the majority of the professionally active population departs from home between 7:00 and 9:00 and returns between 17:00 and 18:00. Deviations among the scenarios aim to capture the impact of different behavioural and social life patterns as well as the consumer acceptance of EV charging strategies. For example, according to Dallinger and Wietschel (2012), indirect charging with electricity tariff incentives is more beneficial as there are higher probabilities of acceptance than direct external control.

According to Table 4.20, in 2030, under the assumption that EVs are charged with slow chargers at home or work, there is a requirement for six hours of charging to reach a 100% SoC. On a daily basis, this is reduced to two hours. With the use of fast chargers in public spaces, one hour is sufficient and can usually be combined with the return at home. The public charging profile is combined with a scheduled one assuming that 40% are charging their cars at home during the night and the rest, 60%, with public chargers during the evening, inspired by the analysis conducted (Virta, 2019). By 2040, faster chargers will become available in the market and affordable. In this respect, biweekly charging requires only two hours, with the requested load rising steeply. The charging timespan is shortened to 20 min for public charging. However, super-fast charging comes with a cost, as despite the lower number of EVs connected simultaneously to the grid, there is a tradeoff related to the chargers' increased capacity affecting the charging loads.

Table 4.20: G2V charging scenarios description

N	Category	Charging Profile Scenario	Timeframe		% of EVs connected to the grid simultaneously (hourly)	
			2030	2040	2030	2040
I.a	**Controlled**	Scheduled	00:00-7:00	00:00-7:00	100%	50%
I.b		Scheduled (daily)	00:00-7:00	00:00-7:00	20-40%	20%
II.a	**Uncontrolled**	Unscheduled	18:00-01:00	18:00-22:00	100%	50-100%
II.b		Unscheduled (daily)	18:00-22:00	18:00-21:00	30-70%	20-40%
II.c		Public Charging[43]	18:00-20:00	18:00-20:00	30%	30%
			00:00-7:00	00:00-7:00	40%	20%
III.a	**Morning**	Morning	10:00-16:00	10:00-15:00	100%	50%
III.b		Morning (daily)	10:00-16:00	10:00-15:00	20-40%	20%

[43] Biweekly night charging for the number of vehicles which have access to private chargers

The charging profiles presenting the EV loads for S1 and S2 are illustrated in Figure 4.22 to Figure *4.23*. The time duration of biweekly charging profiles is anticipated to shift during the day. The daily profiles indicate lower demand as they occur more frequently. Opportunistic, unscheduled daily charging assumes more cars charging simultaneously compared to the rest of the scheduled scenarios. Daily morning charging assumes that most active users will schedule to plugin their car during the first hour they arrive at work and before they leave but less during lunchtime. In 2040, the charging scenarios concept is anticipated to remain the same; however, charging becomes faster while taking advantage of high-capacity chargers. As a result, larger EV load profiles are recorded in smaller periods stressing further the system.

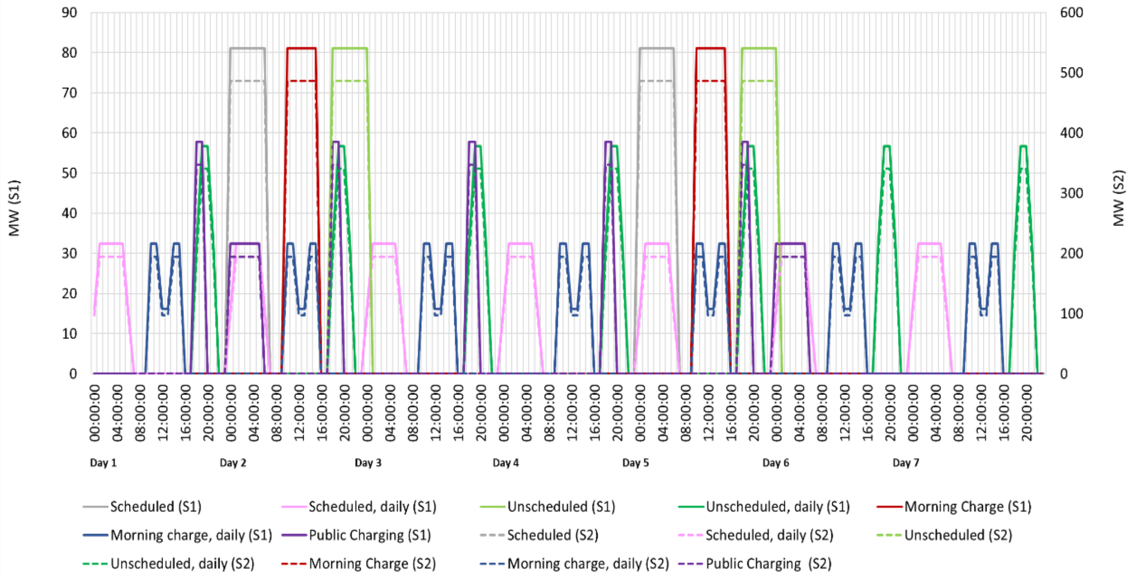


Figure 4.22: Charging profiles 2030 - S1 and S2

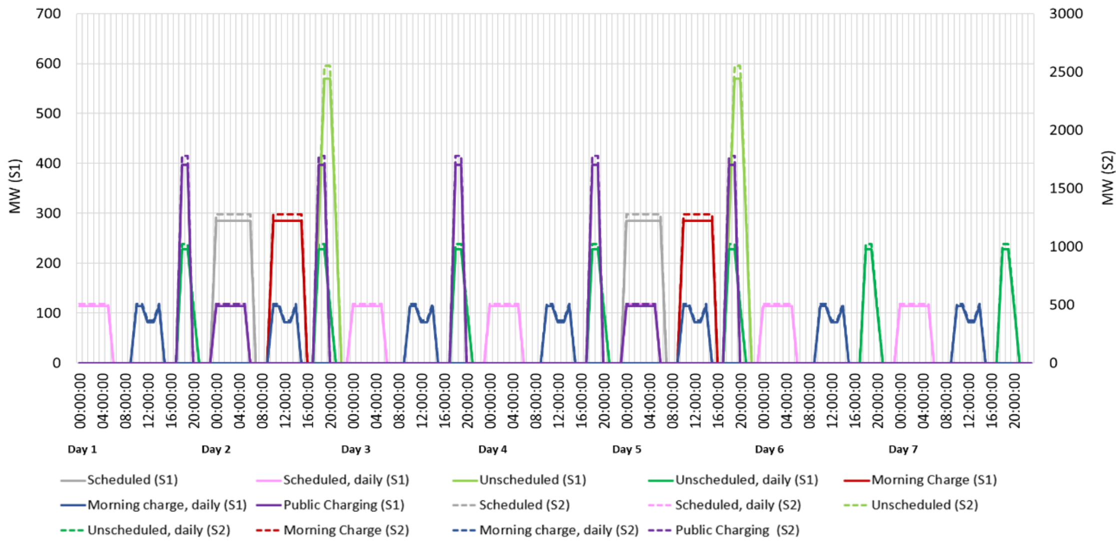


Figure 4.23: Charging profiles in 2030 – S1 and S2

4.7.3.1 *Tourism impact*

The above scenarios concern the local fleets possessed by islanders. However, this approach does not encounter the significant impact of tourism activities on the utilisation of electric vehicles. Therefore, the impact on local grids from 'imported' electric vehicles belonging to or used by the tourists during the MAX week is investigated. The rental car companies listed on each island and their available fleet were recorded (Hellenic Republic - Ministry of Tourism, 2018). That load was extracted from average and minimum weeks EVloads and added during the maximum load week in August. Furthermore, imported EVs that travel with ferries were considered alongside the local fleet during that week. Tourism projections per region were considered as described previously to capture the volume of tourists that will arrive on the islands. According to data from the Hellenic Statistical Authority (2011), tourists were divided between those arriving by plane and ferry. It was assumed that 60% possess a car with three passengers per vehicle (Benaki, 2019; Hellenic Statistical Authority, 2019c). The final number of additional EVs due to tourism activities is illustrated in Figure 4.24, showcasing such a scenario's extensive impact, adding double the EV capacity already existing in the islands' regions.

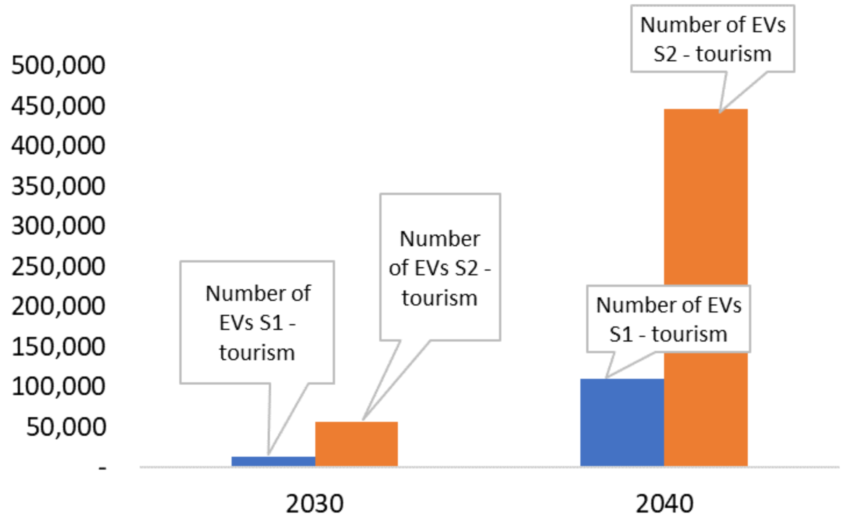


Figure 4.24: Number of additional EVs due to tourism activities

A hybrid-controlled charging pattern was adopted, assuming that 30% of the hotels will possess chargers available for their customers while 70% will charge during the day with public chargers. By 2040, the number of hotels that can offer night charging will increase to 60%, considering learnings from the US[44] (Fox, 2018). The charging times are distributed harmoniously across the day, as presented in Table 4.21. The tourism scenario is combined with the public charging option to test the system's impact under a critical pattern. As mentioned earlier, public charging is avoided on the weekends and public holidays[45]. The charging profiles for the two scenarios S1 and S2, are illustrated in Figure 4.25 and Figure 4.26.

[44] https://www.plugshare.com/map/hotels

[45] such as the 15th of August

Table 4.21: Charging patterns in the Tourism scenario

N	Category	Charging/ Discharging profiles	Time-frame 2030	Time-frame 2040	% of EVs connected to the grid simultaneously (hourly) 2030	% of EVs connected to the grid simultaneously (hourly) 2040
IV	**Tourism**	Timeframe of charging	00:00-07:00		10% in hotels	10% in hotels
			10:00-13:00,16:00-19:00		4-8% in public chargers	2.8% in public chargers
		Timeframe of discharging	7:00-10:00, 19:00-00:00		Driving or parked - not plugged in	

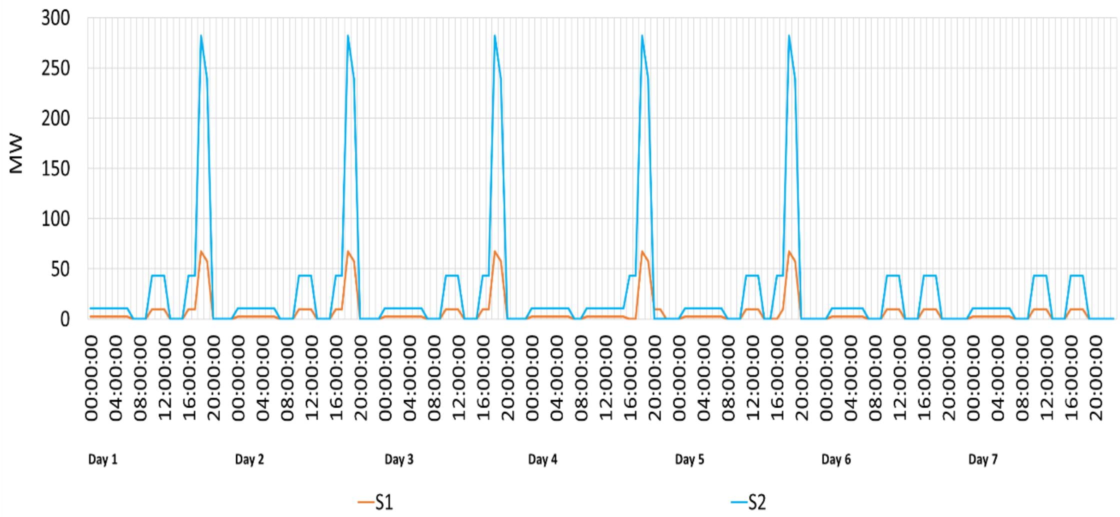


Figure 4.25: Charging profiles in 2030 - S1 and S2

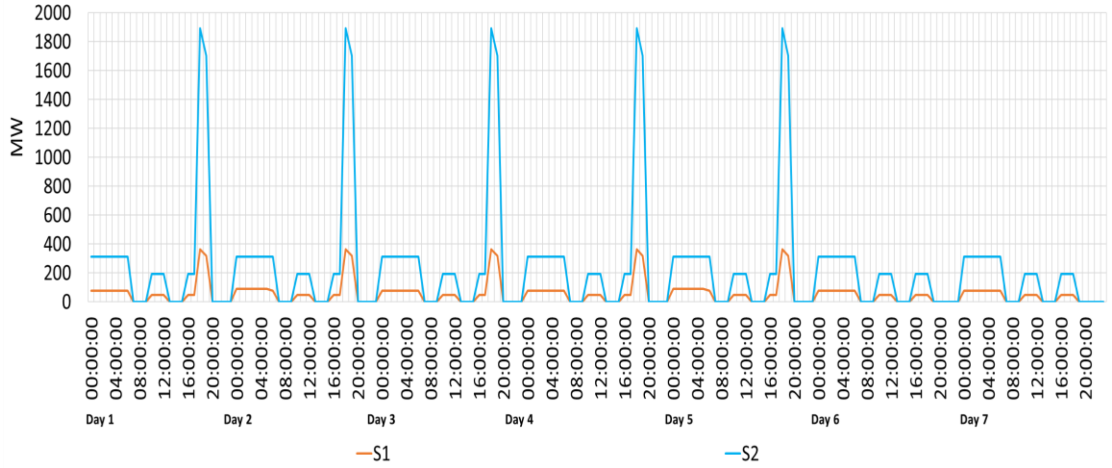


Figure 4.26: Charging profiles in 2040 - S1 and S2

4.7.3.2 *Vehicle to Grid*

The opportunity of having EVs exchanging electricity with the grid may have considerable economic benefits. However, the V2G concept behaves similarly to utility-scale batteries with additional constraints to meet the drivers' requirements. By adjusting their charging levels, the EVs can flatten peak loads, fill load valleys and provide ancillary services to assist in the real-time balancing of the network; in other words, acting as a demand response mechanism accommodating renewables intermittency. Furthermore, smart charging could support distribution system operators to mitigate congestion, help consumers manage their energy consumption, and increase their rates of renewable power self-consumption. According to Bundestag (2019), VRES curtailments would be limited to 8% - 13% instead of 10%-23% on a remote island if RES are coupled with V2G smart charging technology. The downside is related to the wear on the vehicle's battery and the transformers and power quality degradation. Besides, smart systems should be integrated into the existing infrastructure, and the necessary policies as well as market instruments ought to allow for the wide adoption of such a technology.

V2G scenarios are explored herein to investigate whether the above justification could demonstrate a suitable business model for the Greek islands' power systems under an Autonomous or Interconnected state. This analysis assumed that the necessary smart charging infrastructure is already available, allowing bidirectional communication for management and billing purposes. In PLEXOS, electricity evicted from vehicles to the grid was imitated using the storage function. In this case, two storage objects were linked to the generator representing the EVs (Figure 4.27). The head storage imitates the vehicle's battery, providing power to the vehicle. In contrast, the tail storage represents a virtual pool from which the head storage can pump electricity and charge the battery. The discharging of the car takes place through an hourly 'natural outflow' function representing the energy consumed on each island/node (i) and aggregated to the region level (R) through the day, assuming a timespan between 09:00 to 18:00, calculated per hour (h) according to the following equation:

$$Natural\ Outflow_{i,h} = Daily\ Distance_i * \ Consumption\ EV_i * \frac{Number\ of\ EVs_i}{Hours\ out\ of\ plug}$$

Eq. 4.39

In order to keep the balance between the two storages, the same positive natural inflow is entering the tail storage. When the car is not connected to the grid, the power generator capacity and the pumping loads are set to zero. Herein, two charging scenarios were included, the **V2G unconstrained** and the **restricted** for the two EV penetration Scenarios (S1 & S2), as indicated in Table 4.22.

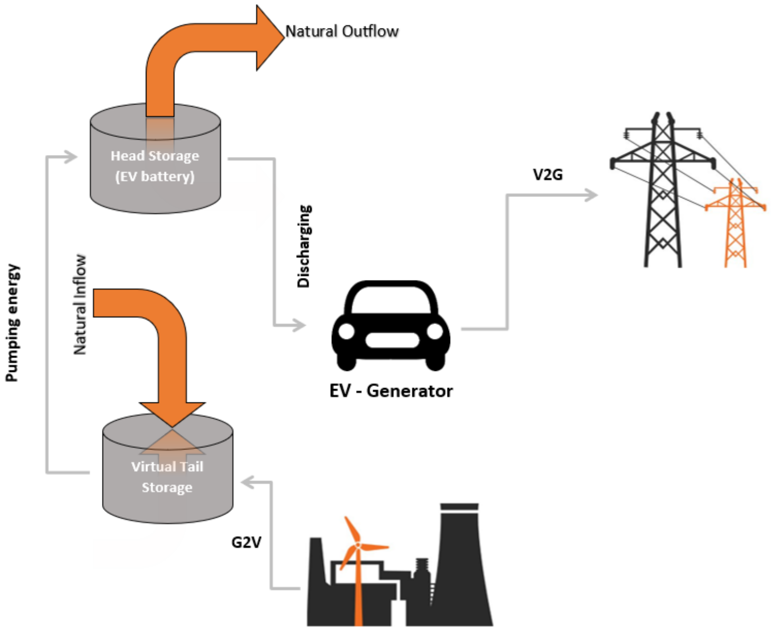


Figure 4.27: V2G schematic applied in PLEXOS model

Table 4.22: V2G and G2V Charging Profile

N	Charging Profile Scenario	V2G and G2V Time frame		Discharging (off the grid)
V.a	V2G	18:00-23:00	00:00-08:00	9:00-18:00
V.b	V2G - restricted	02:00-08:00		9:00-18:00

Electric vehicle discharging entails variable costs which contribute to configuring the merit dispatch order on each island's electrical system. The EVs' electricity cost is set in the PLEXOS model as described in Eq. 4.40, which is explicated according to Kempton and Tomić (2005). For providing an incentive to EV owners to contribute through pooled EV groups to the electricity market, a markup equal to 10% of the cost of electricity C_{el} was considered in the model.

$$C_{V2G} = {}^{110\% * C_{el}^{EV}}\!\big/_{\eta_{conv}} + C_{deg}$$

Eq. 4.40

Where:

'C_{el}^{EV}' the cost of electricity for discharging the car during the valley and off-valley hours;

'η_{conv}' is the discharging efficiency of the EV battery;

'C_{deg}' is the cost associated with the car's degradation relevant to the V2G; operation, calculated according to Eq. 4.41.

$$C_{deg} = {}^{C_{bat}}\!/_{(E_C * BSEV_i * DoD)}$$

Eq. 4.41

Where:

'C_{bat}' is the cost of the EV car battery, including the replacement labour cost;

'E_c' is the battery's lifetime in cycles in Table 4.23*;*

'$BSEV_i$' is the total size of the EV battery per island/node, as included in *Table 4.18.*

Table 4.23: EVs specifications considered in the V2G analysis (Cole et al., 2019; Mongird et al., 2019)

Indicator	**Value**
Reference cost	145 €/MWh (2030)
	125 €/MWh (2040)
η_{conv}	88%
DoD	80%
E_c	0.01% degradation per cycle[46]

[46] Assuming two cycles per week for 52 weeks, per year, in 12 years, the car will have lost approximately 12.5% without V2G operation. Under a V2G scenario the lifetime of a battery can be reduced to 7-8 years

4.8 Validation

PLEXOS model in short-term operation is validated by comparing real and historical data against the BAU modelling outputs for 2016, as HEDNO (2017) provided. The islands were split into three comparable groups: large, medium, and small-sized systems defined by RAE (2021c). The results illustrated a high-level precision for electrical systems such as Crete and Rhodes (Figure 4.28), where detailed technical operation features (heat rates, max and min stable level) have become available and included in the modelling exercise.

Minor discrepancies in the range of 2 - 15% are recorded in medium and small-sized island systems, as illustrated in Figure 4.29 and Figure 4.30. The modelling exercise for these AES incorporates a set of assumptions with lower granularity and precision recovered from the literature. These assumptions concern thermal stations' technical operating conditions resulting in mismatches compared to the actual data. In most cases, PLEXOS generates slightly higher results, primarily due to not enforcing all technical operating constraints. Another possible reason might have been underestimating possible real-life outages frequently observed during the summer months on the Greek islands, as average values were included for 2015 and 2016. For example, higher generation on Karpathos and Kasos islands could be attributed to the aforementioned reasons and underestimating cable losses. A side effect of such discrepancies may lead to wind energy curtailments that might or might not be reflected in the modelling simulation subject to the RES generation, the technical operating parameters, and the model's constraints. The modelling outputs for solar and wind are close to the real-life measured data with discrepancies in the range of 3-10% for solar and 2-18% for wind. As anticipated, wind generation entails higher stochasticity through the years.

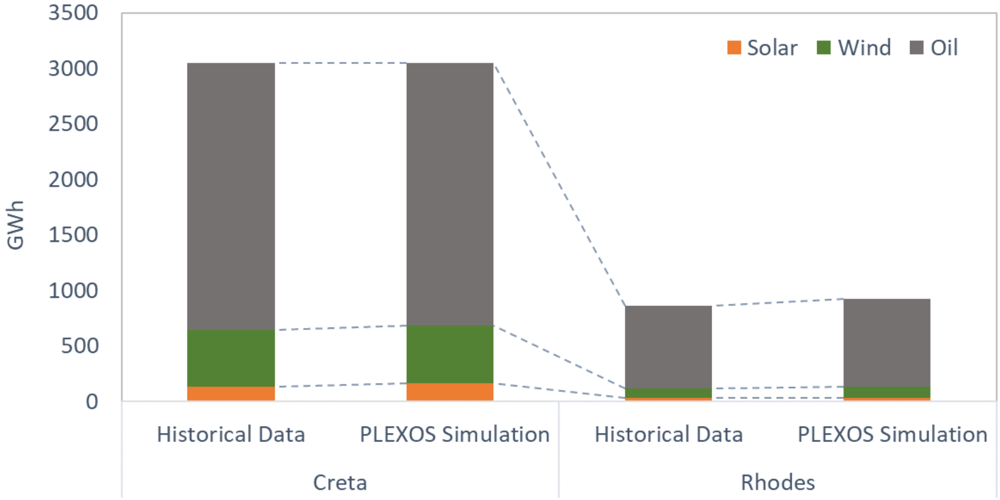


Figure 4.28: 2016 Historical vs. simulated power generation data for large-sized AES

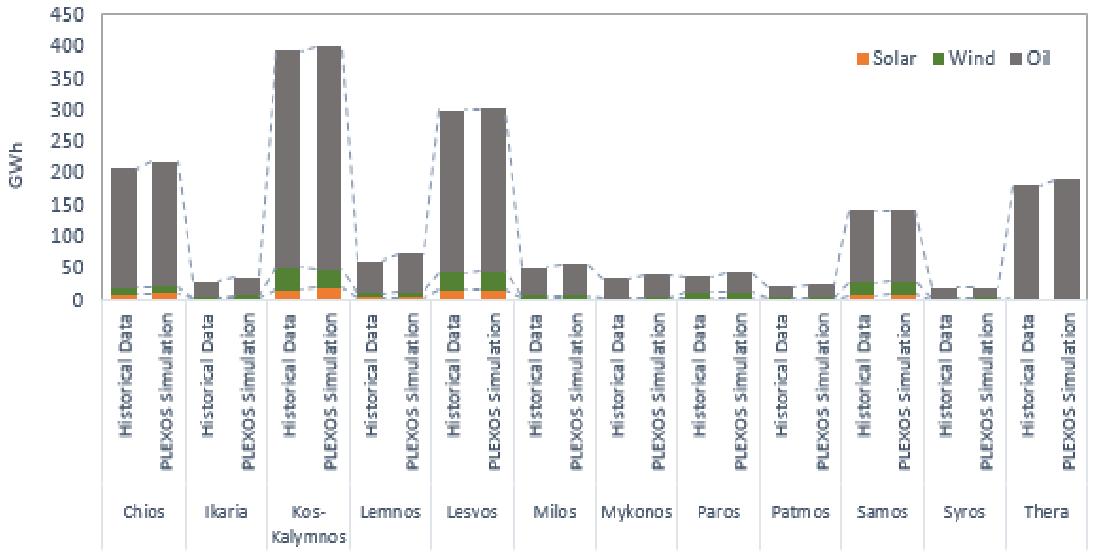


Figure 4.29: 2016 Historical vs. simulated generation data for medium-sized AES

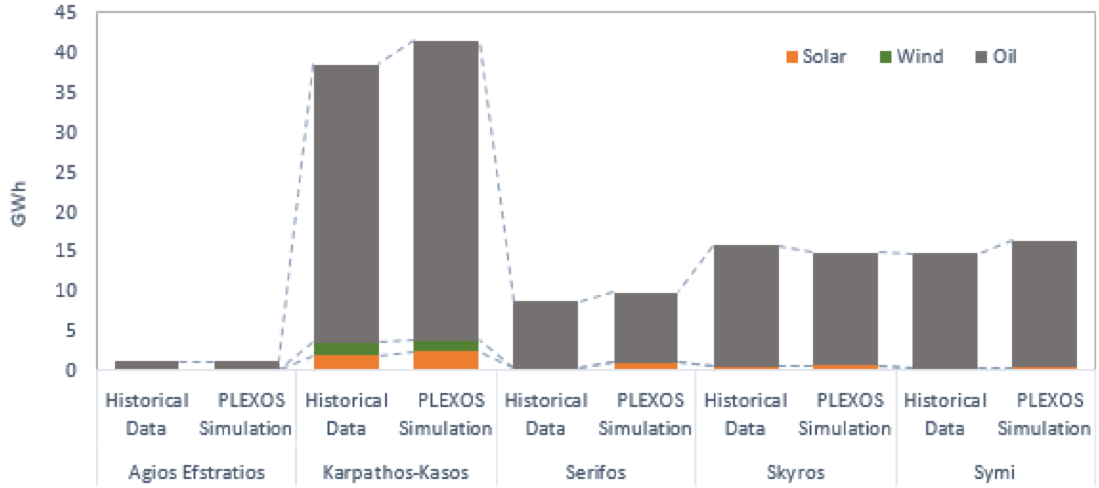


Figure 4.30: 2016 Historical vs. simulated power generation data for small-sized AES

Cumulative results concerning the whole island region are illustrated in Figure 4.31, considering the BAU scenario. The historical data versus PLEXOS projections show minimum differentiation between 2017 and 2018. By 2019, the model does not capture wind and solar development in the region resulting in a discrepancy of 212 GWh. Finally, in 2020 there is a relative increase in renewable energy generation captured by the model; however, 2020 may be considered an outlier due to the COVID-19 pandemic, resulting in significantly lower demand levels than anticipated.

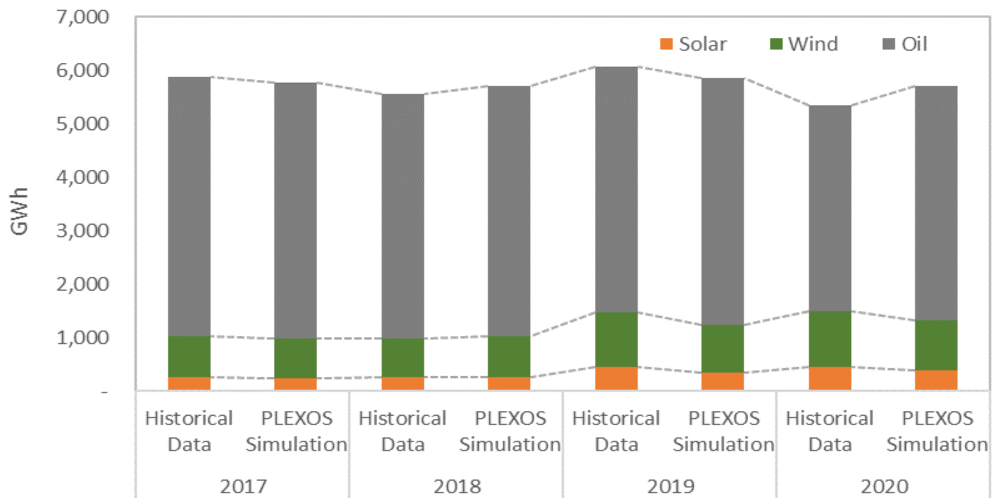


Figure 4.31: 2017-2020 historical vs. simulated power generation data for the Greek islands' region

Average generation costs from the PLEXOS model were compared with real generation costs (Figure 4.31). The generation costs discrepancies are attributed to the operating conditions, fuel prices, taxes, and additional indirect costs assumptions included in the model. Furthermore, the average tariffs for RES generation do not always reflect individual projects' characteristics. The divergence goes up to 31%, with the highest recorded on Crete and Ikaria. The main reason is the hydro storage stations on the islands, which incorporate high-level aggregated data available regarding the operational reservoirs and power plants. Furthermore, uncertainty in assumptions regarding VO&M, FO&M, start-up, and shut-down costs increases such discrepancies. Overall, despite the minor discrepancies, the modelling approach and the assumptions employed prove to simulate and optimise the future operation of the Greek islands' power sector under various scenarios.

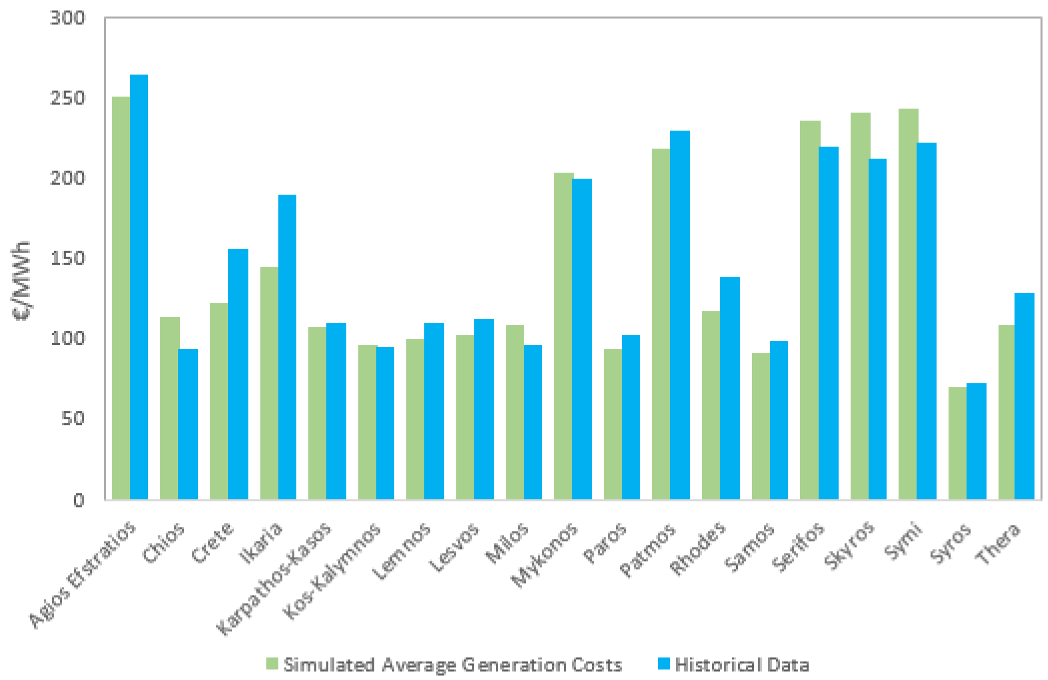


Figure 4.32: 2016 Historical vs. simulated average power generation costs per AES

5. Results assessment for secure, affordable and sustainable electricity on the Greek islands

5.1 Summary

This chapter narrates the results of the proposed scenarios according to the Energy Trilemma Index (ETI): Security of Supply, Economic Affordability and Environmental Sustainability as configured by the World Energy Council (2019) for the future Greek islands' electricity system assessment. Part of this chapter has been published in (Zafeiratou and Spataru, 2022).

The first section includes results considering the Greek electricity mix, emphasising RES penetration subject to the principal scenarios; also, a sensitivity analysis is applied. The short-term dispatch profile, including the principal scenarios, is presented with an analysis of the generation mix. Furthermore, the system reliability and the recovery capacity are discussed, considering the CRM, LOLP and unserved energy. The sensitivity analysis concerns the unserved demand, while a further assessment of different RES penetration levels is included. Also, the seasonality impact is evaluated. The power flows exchange profiles between the islands' region and the NGS and an overview of the BESS utilisation are provided. Finally, the EVs implications on the security of supply on the Greek islands for 2030 and 2040 are calculated under the Autonomous Batteries (AB.y.1.0) and Interconnection (I.x.1.0.a) scenarios.

The second section explores the economic impact of interconnections, energy storage and autonomy on the total system costs at a national and regional level. This is attained while presenting total system costs and levelised costs per region. The power generation costs in hourly average prices and the SMP at a national level are discussed, emphasizing possible cost reductions. Moreover, the economic implications of electromobility on islands are presented.

The third section around environmental sustainability is focused on CO_2, NO_x and SO_2 emissions measured in CO_2eq. The emissions at the national and regional levels are presented against the targets set for emissions reduction by 2030 and 2040. Emissions intensity is also included for each of the main scenarios. Finally, the environmental impact of EVs concerning emissions from the electricity sector but also emissions savings and the avoided consumption of fossil fuels from the transport sector are presented.

Overall, it is concluded that interconnecting the Greek islands is inevitable to guarantee a secured, clean and affordable electricity system for the future. However, certain smaller AES may operate optimally under an autonomous-battery case (AB.x.1.0.a). BESS could play a catalytic role in eliminating power shortages and reducing further emissions to reach the ambitious goals in both contexts.

5.2 Security of supply

5.2.1 Long-term RES integration

5.2.1.1 *System level*

Renewable energy development is a high priority for Greece to align with the European Green Deal and achieve climate neutrality by 2050. The Greek NECP has proposed ambitious renewable energy targets across all energy sectors, with the power sector leading the national decarbonisation strategy (Hellenic Republic - Ministry of the Environment and Energy, 2019a). Despite their small size, the Greek islands show increasing demand trends due to high levels of tourism, adding 10 GWh to the system by 2040, highlighting the importance of careful energy planning. In parallel, they can play a significant role in renewable energy growth when combined with parallel infrastructure deployment.

By 2030, the system responds to thermal generation restrictions imposed by Directives 2010/75/EU and 2015/2193/EU while 2.5 GW capacity of energy storage is added to facilitate intermittent RES acceleration in the Autonomous Scenario and 1.5 GW in the Interconnected, excluding 2 GW in the mainland. The scenarios assuming the massive scale-up of battery storage systems (AB.x.1.0.a and IB.x.1.0.a) are the front runners in RES deployment with 37 and 38.6 GWh renewable energy generation, respectively, according to Figure 5.1. RES development in the mainland is slightly affected by the different trajectories until 2030, steered mainly by the phase-out of lignite generation. In light of these developments, all scenarios but the BAU Autonomous (A.y.1.0.a) assume the replacement of approximately 12,000 GWh lignite-fired generation in operation in 2016 with natural gas, wind and solar capacity. Furthermore, roughly 300 MW RES capacity is displaced from the mainland to the islands under the interconnection pathway, benefiting from increased capacity factors. In this respect, the interconnection scenarios increase the supplied power's efficiency by reducing the total generation by 3,000-4,000 GWh annually compared to the autonomous pathway while reducing power generation curtailments on islands. In the autonomous case, renewables in the continental grid are growing independently, receiving a boost under the 2030 EU targets supported by various mechanisms. Islands' participation in the total RES share is limited between 6% in the autonomous and 17.5% in the Interconnection Scenarios, considering the available resources and infrastructure. Shares remain relatively low since the market anticipates the Dodecanese and Northern Aegean's large-scale interconnections projects in 2030 to proceed with massive RES development in the region.

In 2040, the Interconnection pathway coupled with battery storage systems (IB.x.1.0.a) will take the lead in renewable energy production with 51.5 GWh. The Autonomous Scenario (A.y.1.0.a) records the lowest RES levels (32.7 GWh) due to the continuation of renewables integration constraints in isolated island grids, while no regulation to facilitate offshore wind deployment has been foreseen.

Between 2030 and 2040, the Autonomous Scenario reaches a saturation level of intermittent energy technologies; islands such as Samos and Chios showcase RES penetration, exceeding 35% of the total installed capacity. In the case of Crete, it reaches 40% without surpassing the operational threshold of 35% as it includes dispatchable RES technologies such as hydro. In the mainland, incentives for sustainable energy investments are contained, with natural gas being the dominant fuel, while lignite-fired generation is not eliminated according to the 2020 national energy transition plans. RES generation on islands represents only 12% of the national RES production, and in the case of autonomy supported by battery electricity storage, it increases to 27%. An integrated electricity system under I.x.1.0.a and IB.x.1.0.a scenarios incorporating the continental network and the islands deploys its full clean energy potential while supporting offshore wind reflected in an additional 3,600 GWh of clean energy annually. As such, 30-32% of the renewable generation in Greece is produced in the islands region.

Only IB.x.1.0.a attains the ambitious 2030 EU and national targets imposing 57% and 61% share of renewables in electricity generation followed by AB.x.1.0.a. The main reason for limiting further RES expansion beyond the access to the HV grid is related to natural gas infrastructure investments already in place (as indicated in ANNEX II.b). Furthermore, more than 3.4 GW will be commissioned between 2020 and 2025 (Hellenic Republic - Ministry of the Environment and Energy, 2019a; IPTO, 2021b). 16,000-18,000 GWh of RES are generated on islands in the Interconnection Scenario, signalling for relatively lower RES deployment on the mainland. Similar to 2030, in 2040, the EU and national targets proposing 70% and 72% RES share are reached only by the Interconnection-Batteries Scenario (IB.x.1.0.a).

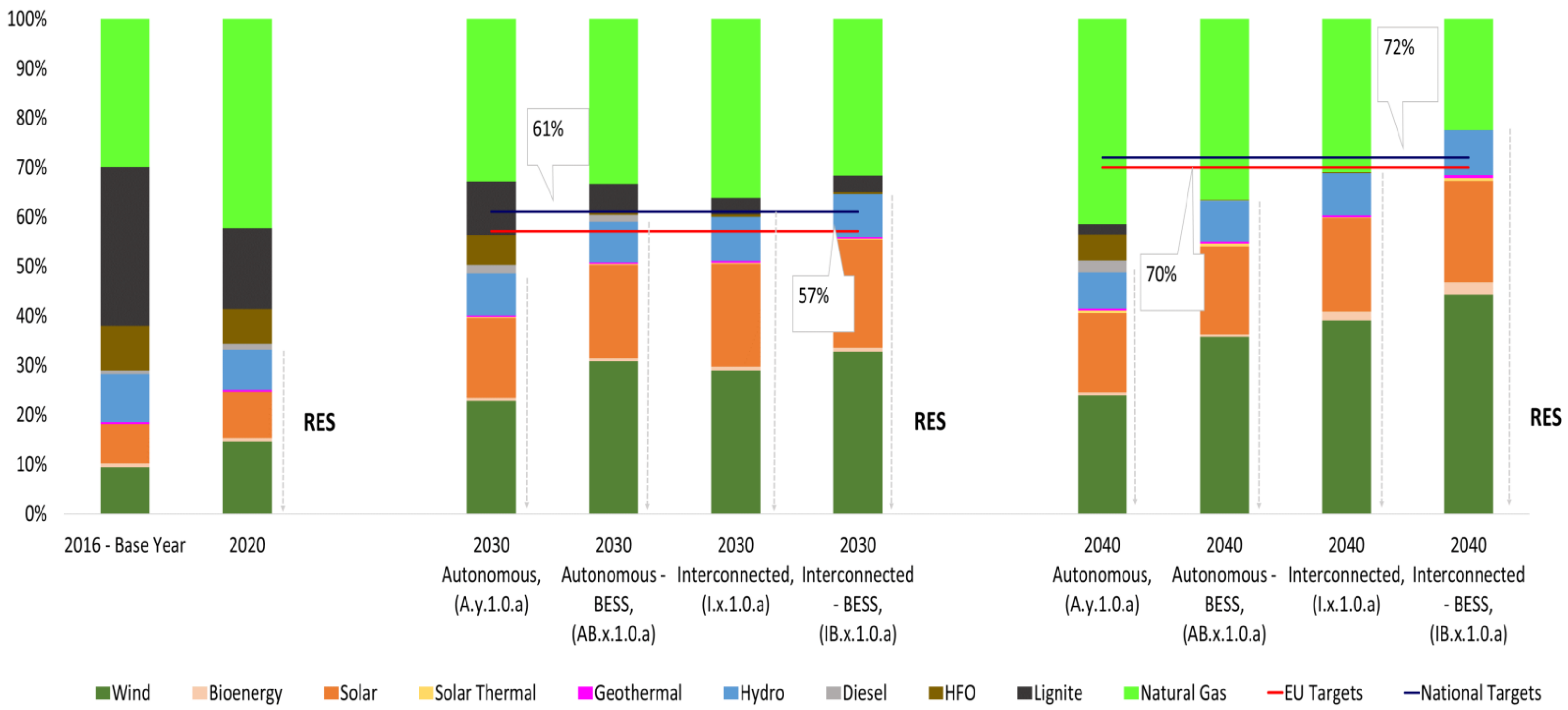


Figure 5.1: Annual power generation at the system (national) level - Principal scenarios

5.2.1.2 *Sensitivity analysis*

Figure 5.2 illustrates the cumulative renewable energy generation for the entire projection horizon of 2020 - 2040 under the 35 examined scenarios. RES share represents the percentage of renewables participating in the local generation mix. Concerning offshore wind, only the local demand's percentage contribution was accounted for, as the rest is transmitted to the continental part.

Under the Autonomous Pathway (Storyline A), it is clear that in the BAU Scenario A.y.2.0, a fixed trajectory of 2016, considering limited RES deployment, energy isolation and modest policies, the lowest levels of renewable energy (33,600 GWh or 24% share) are recorded. Increased demand through the Low_Eff scenario combined with the Current Policies IEA fuel projection in A.y.2.1 would lead to similar results. Under operational restrictions limiting capacity factors in A.x.2.0, the shift to higher clean energy integration inevitably increases to 32%, while if additional RES capacity is available to be installed (A.x.1.0), the share exceeds 52%. Following on, A.y.1.0.b and A.y.1.0.d show a considerable increase of 20% in RES generation, assuming the Cycladic interconnection and offshore wind projects leading to 45-46% RES share. Particularly for Crete, the largest NII, in case natural gas infrastructure is introduced (A.y.1.0.e), limits by some means the massive RES scale up on the island to 20% compared to the A.y.1.0.a., with the average share in the region being reduced by 2%. The storage deployment triggers RES growth as hybrid wind-battery systems try to fill the generation gap. Sensitivity analysis in fuel scenarios shows that the ultimate case is driven by ‘New Policies’ when combined using Low Sulphur oil at a national level, reaching 79% RES share in AB.x.1.0.a. It comes as no surprise that under a scenario where generation restrictions are not imposed (AB.y.1.0), renewables continue sharing 76% of the electricity mix, as they become the cheapest available option. On the other hand, the thermal generation does not restrict the deployment of RES in this pathway but achieves to eliminate the uncertainty for capacity reserves.

Assuming interconnections occur under a low-environmental awareness context, where RES deployment and energy efficiency measures are limited, the Interconnection Scenario I.x.2.1 would only record 75,199 GWh and 67% RES share. It is followed by the I.y.1.0.a. lifting local thermal generation restrictions in the interconnected context constraining local RES generation to 72% (I.y.1.0.a) compared to 84% under the I.x.1.0.a principal scenario. The IB.x.1.0.b batteries-interconnection scenario, despite representing the cost-optimal case recording 83% of RES share in the islands region, in absolute numbers, it generated only 82,800 GWh, assuming no offshore wind development while shifting power generation to the mainland. This is because RES deployment takes place only on large-sized island systems prioritising cost-competitiveness. In contrast with the Autonomous-Batteries set of scenarios, it is evident that in the interconnected system where demand can be supplied through different generation streams, the continuation of oil-fired operation will inhibit a marginally larger share of renewables. In the rest of the Interconnection scenarios, we notice that demand, fuel, and carbon prices have a much more prominent role than the Autonomous Batteries case as generation in the mainland is competing with the islands region. In contrast, RES deployment is a oneway approach to cover demand on the islands in the autonomous case. In this respect, IB.x.1.0.a, the scenario combining interconnectors with storage to enhance systems reliability and flexibility, allows for the highest average RES penetration in the local system, equal to 86% between 2020 and 2040. The I.x.1.0.f scenario assuming the introduction of natural gas on the island of Crete while interconnected would reduce Crete's renewables generation by 26% and the regional RES generation by 14%, whilst raising the share to 87%, as imports from the mainland are displacing local generation.

The variations among the demand scenarios show that in the Low_Eff demand scenario deriving from ISLA_EGI, reflected in I.x.1.1, RES share declines by 4%. Lower demand levels (I.x.1.2.a) in the High_Eff Scenario would leave RES generation intact while the remaining demand would be supplied from the mainland. This highlights that the various trajectories will exploit the maximum available RES capacity irrespectively of demand fluctuations. There is little margin for additional capacity to be deployed in higher demand growth, leading to a marginal increase in local oil-fired generation. The ultimate scenario in terms of RES deployment is the I.x.1.2.b (174,000 GWh/90%) which assumes an ambitious High_Eff Scenario, with the aggressive carbon costs boosting clean energy technologies emergence without limiting local RES deployment. In this case, interconnectors provide channels for exporting the surplus to the mainland, while local demand decline does not affect RES growth. Such results highlight the impact of energy efficiency policies in conjunction with infrastructure development.

RES deployment at the island level is primarily associated with the size of the system. According to the results, Crete leads clean energy generation across all scenarios. However, it is worth noticing that while marginal variations are recorded among the Autonomous Scenarios, under the Interconnection Scenarios, RES capacity is 250% higher. Crete is followed by the Rhodes system, which will quadruple its RES generation under the Autonomous Battery Pathway. This is anticipated because Rhodes exploits its available RES resources supported by local storage to meet daily demand due to energy isolation. On the contrary, RES generation on Rhodes is reduced by 42% under the interconnection scenario compared to the AB.x.1.0.a case.

Due to its high wind energy potential, which remains unexploited, Skyros will deploy significant RES capacity (333 MW) only under the interconnection pathway to allow the direct export of power to the main consumption centres. In the permitting phase, such a project will undertake part of the costs for the underwater cable between Skyros and the mainland. The Northern Aegean Sea region could quadruple its RES generation following its interconnection if battery storage is employed. In an Autonomous-Batteries Pathway, RES generation increases by 300% compared to a BAU context. For the Cycladic islands, we notice that under the Autonomous Battery Pathway, there is a need for large-scale onshore RES projects to meet the demand. However, the deployed capacity should respect spatial and environmental constraints. For example, in Syros, for covering the demand loads under the Autonomous-Batteries pathway, wind development has to overrule spatial restrictions of 0.53 W/T per 1000 acres by installing 38 W/T when the limit is 35 W/T. Another critical dimension not captured herein affecting the deployment of clean energy is the public acceptance in the touristic islands. Under the Interconnection storyline, the installed RES capacity is reduced by approximately 40%. Specific systems such as Kos-Kalymnos, Lemnos, Paros and Syros will keep operational thermal capacity until 2040. Nevertheless, the majority, e.g. Crete, Karpathos Milos, Mykonos, Thera, Rhodes, Symi, Chios, Ikaria and Agios Efstratios, decommission their oil-fired units or maintain them in cold-reserve with a total capacity of 972 MW. The capacity of oil-fired units is reduced drastically under the IB.x.1.0.a scenario with only 400 MW kept in cold reserve and no operational units.

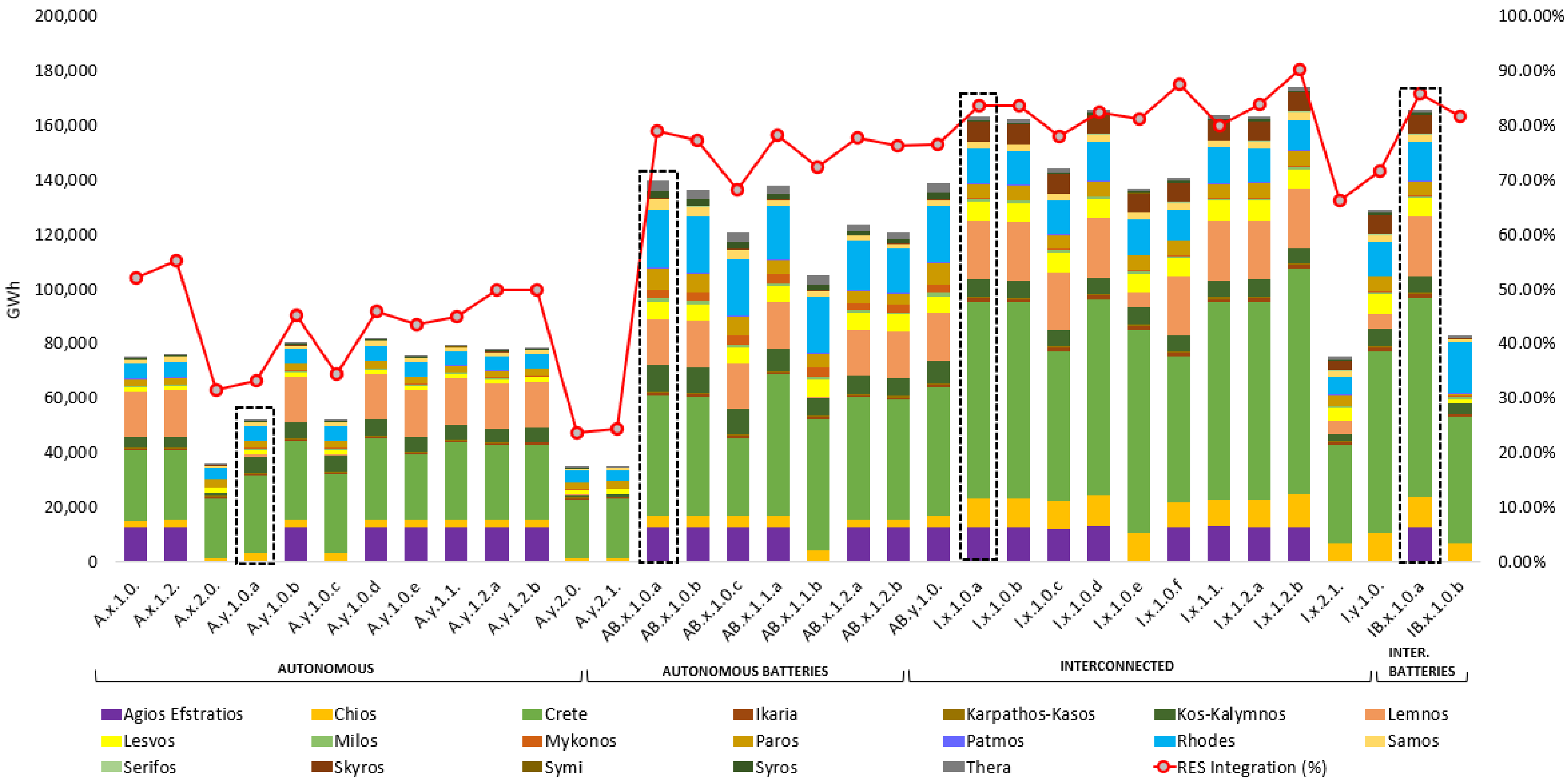


Figure 5.2: Regional cumulative RES generation (2020-2040) in the Greek islands' region – Sensitivity analysis

5.2.2 Short-term dispatch

The Principal Scenarios representative hourly generation profiles, including an additional scenario for the Autonomous-Batteries Pathway (AB.x.1.0.a) assuming no generation restrictions for the Greek islands region, are illustrated in Figure 5.3 to Figure 5.8. The profiles are extracted for representative weeks in May, August and November for the milestone years, as explained in Section 4.3.1. In the Autonomous Scenario (A.y.1.0.a), the primary power source continues to be imported oil fuels such as HFO and diesel oil, sharing on average 80% of total generation[47]. HFO is mainly used to cover the baseload, while on certain islands such as Serifos and Agios Efstratios etc., where no HFO is used, this role is taken over by diesel, which is otherwise used to cover peaks. By 2040, diesel will become the primary fossil fuel due to its chemical consistency, which entails lower emissions and carbon costs. Renewables continue to have a limited role, representing 19% in 2030 and 23% in 2040 among those weeks. The RES generation mix consists of wind, solar, hydro, and in complementarity geothermal, while bioenergy only has a minimal role in the autonomous pathway after 2030.

Significant unserved demand during morning and evening peaks equals 3.5% of the weekly demand for 2030 (ranging between 0% for the minimum load week and 10% for the maximum). Unserved demand is escalated to 13% by 2040 over the maximum week. These incidents occur mainly during summer weeks, when demand is considerably higher, while it is eliminated during wintertime. Unserved demand in the form of blackouts is a common phenomenon for the Greek islands region as considering 2016 data, 300 MWh of power shortages were recorded (HEDNO, 2017b). This is estimated to escalate as demand increases while the local networks rely on old-fashioned, inflexible steam and gas turbines.

Unserved demand increases under the AB.x.1.0.a scenario where utility-scale battery storage systems are employed if power generation restrictions are

[47] With higher values recorded over the maximum load weeks and lower over the minimum

imposed. Even though the sizing of the storage systems was designed under the criterion to cover the 90th percentile of the annual peak demand without the support of other local generators; in practice, the hourly dispatch profiles fail to meet demand peaks, recording 5% of the unserved load in the average week and 11% in the maximum. The generation mix consists mainly of wind (39%) while in total, an average of 65% RES integration is achieved already in 2030, which further increases to 75% in 2040. Therefore, conventional fuels such as HFO and diesel have a limited contribution. By 2040, unserved energy is reduced to 2.5-5%, but curtailments increase to 10% as the ‘duck effect’ of a net-load profile becomes more prevalent. In this Autonomous Scenario, bioenergy is marginally higher as it offers the system a low-carbon baseload generation profile. Bioenergy could potentially offer a reliable baseload source for the islands if the raw material source could be secured.

On the other hand, without generation restrictions, the Autonomous Battery Scenario (AB.y.1.0) manages to balance demand and supply effectively, eliminating any unserved demand while reducing curtailments. In the average week, the principal fuel sources remain diesel and heavy fuel oil, sharing 55% of the total generation. During the maximum week, thermal generation is reduced to 33% and the minimum to 11% due to increased RES generation low demand. It is worth noticing that over the minimum week, power shortages are mainly recorded on Crete; therefore, diesel-fueled generators are dispatched during the evening of the 21st of November. Overall, the results show higher wind generation during winter and summer than in spring, while solar power records its maximum efficiency over summer months aligned with data presented in Section 4.4.2. In 2040, RES share increases to 65% versus 36% in 2030 following the installation of offshore wind projects near Lemnos and Agios Efstratios islands, while 52 GWh of wind offshore is exported to the mainland over the mainland a standard week.

During the maximum and minimum load weeks, local offshore wind generation[48], including other renewables, exceeds local demand, leading to 105 and 91 GWh of exports, respectively.

It is observed that despite the phase-out of local thermal generation, the interconnectors do not manage to cover demand continuously, resulting in 3% of demand loads remaining unserved under I.x.1.0.a. In 2030, imports from the mainland will cover 57% of the island region's demand during the average week, while the rest is supplied mainly by local renewable energy systems. On the contrary, higher local RES generation is recorded in the maximum week, limiting imports to 25% of the local demand. Winter months reflected in the minimum week experience low load levels imports contained to 13%. By 2040, the landscape will change as the islands region can export energy to the mainland. Wind energy capacity grows significantly in the area, reaching approximately 3 GW (including offshore wind) compared to 0.8 GW in 2030. Solar power plays a role mostly in the morning peaks. Solar thermal installed only on Rhodes and Crete shifts specific capacity to evening to provide energy over the second daily peak. The most vulnerable islands are the Dodecanese islands. This translates into a RES share of 81%, with imports representing only 13% of the local demand and unserved loads limited to 2.5% during the average week. These figures go as high as 95% for RES in the maximum week with 11% imports and approximately 7% of the local generation exported. Finally, over the weeks experiencing low load levels, 178 GWh of clean energy or 60% of local generation is exported with zero imports while the entire demand is covered by local, sustainable energy. In general, interconnections might affect the island’s local generation to serve demand needs in the continental part as they become part of a broader interconnected system.

Finally, if BESS are installed, represented through IB.x.1.0.a Scenario, variable renewable sources such as solar and wind are successfully managed to

[48] Wind offshore is depicted in the following figures with different colour as the surplus is directly transmitted to the mainland

balance demand and supply and effectively eliminate power shortages. Batteries assist in meeting peak loads by contributing on average to 8% of the weekly demand in 2030 and 2040 dispatched during morning and evening peaks. While minor differences between the average and maximum weeks are observed, these values increase to 24.5% through 41 GWh for the minimum week in 2040 due to high local generation and demand discrepancies. These events lead to frequent arbitrage requirements benefiting from the significant amount of renewable energy swinging in the market. In parallel, part of the loads in the interconnected system is served through exports from the islands region. BESS provide night, valley filling services through charging, absorbing on average 15.5 GWh in 2030 and 16.2 GWh in 2040. In 2030, imports will continue to be vital for the electrification of the islands. Synergies between interconnections and energy storage bring zero wind energy curtailments to the islands. By 2040, the local clean electricity dispatch will cover approximately 70% of the local demand over a representative average week. As strongly interrelated with weather conditions, when maximum loads are recorded, the combination of battery operation and interconnections allows for exporting 25% of the locally produced wind energy to the mainland. During periods with low loads in conjunction with strong winds usually encountered until February, almost the entire demand can be supplied locally, with 119 GWh of the available generation exported.

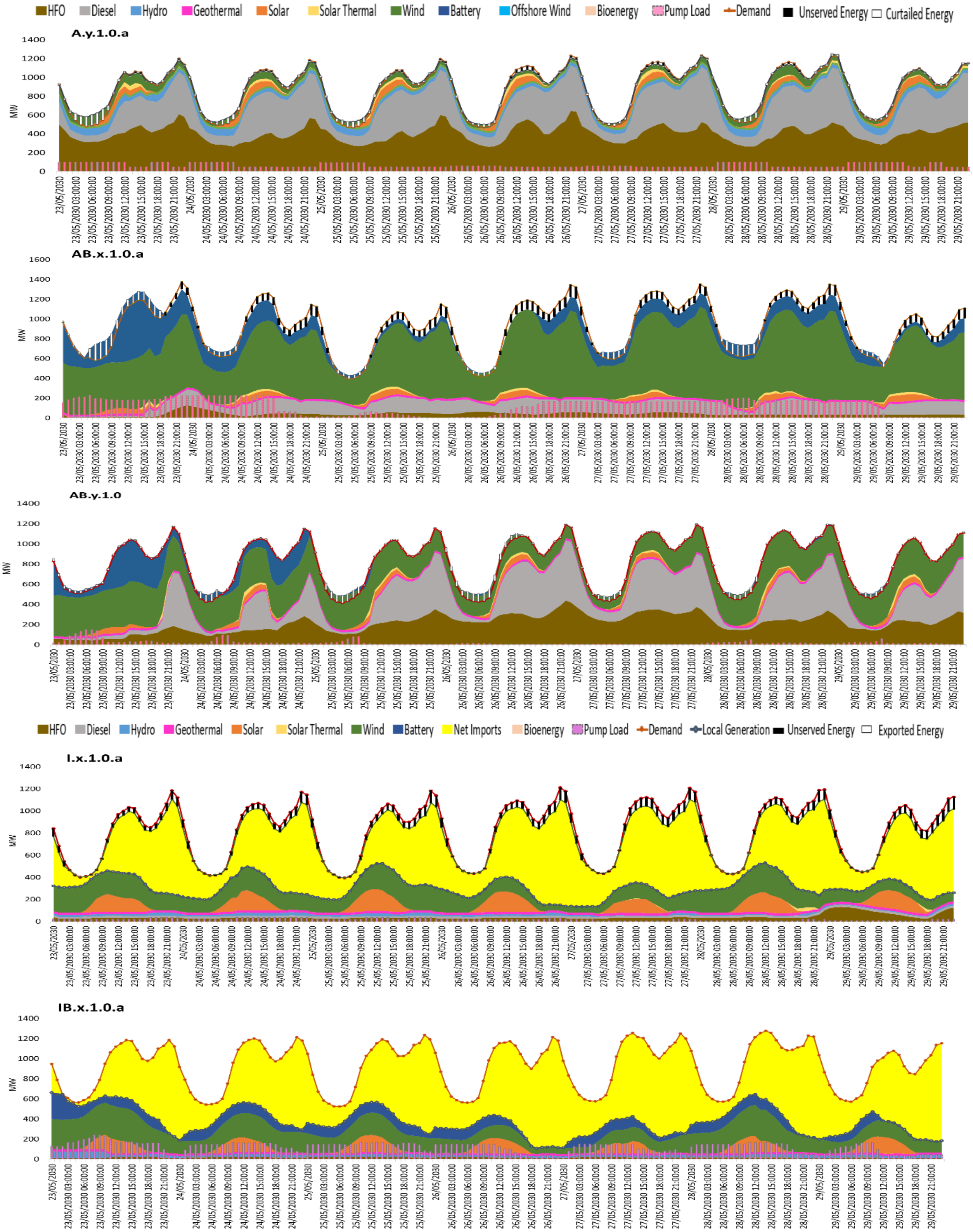


Figure 5.3: Representative weekly electricity hourly dispatch in the Greek islands region for 2030 - Average load week

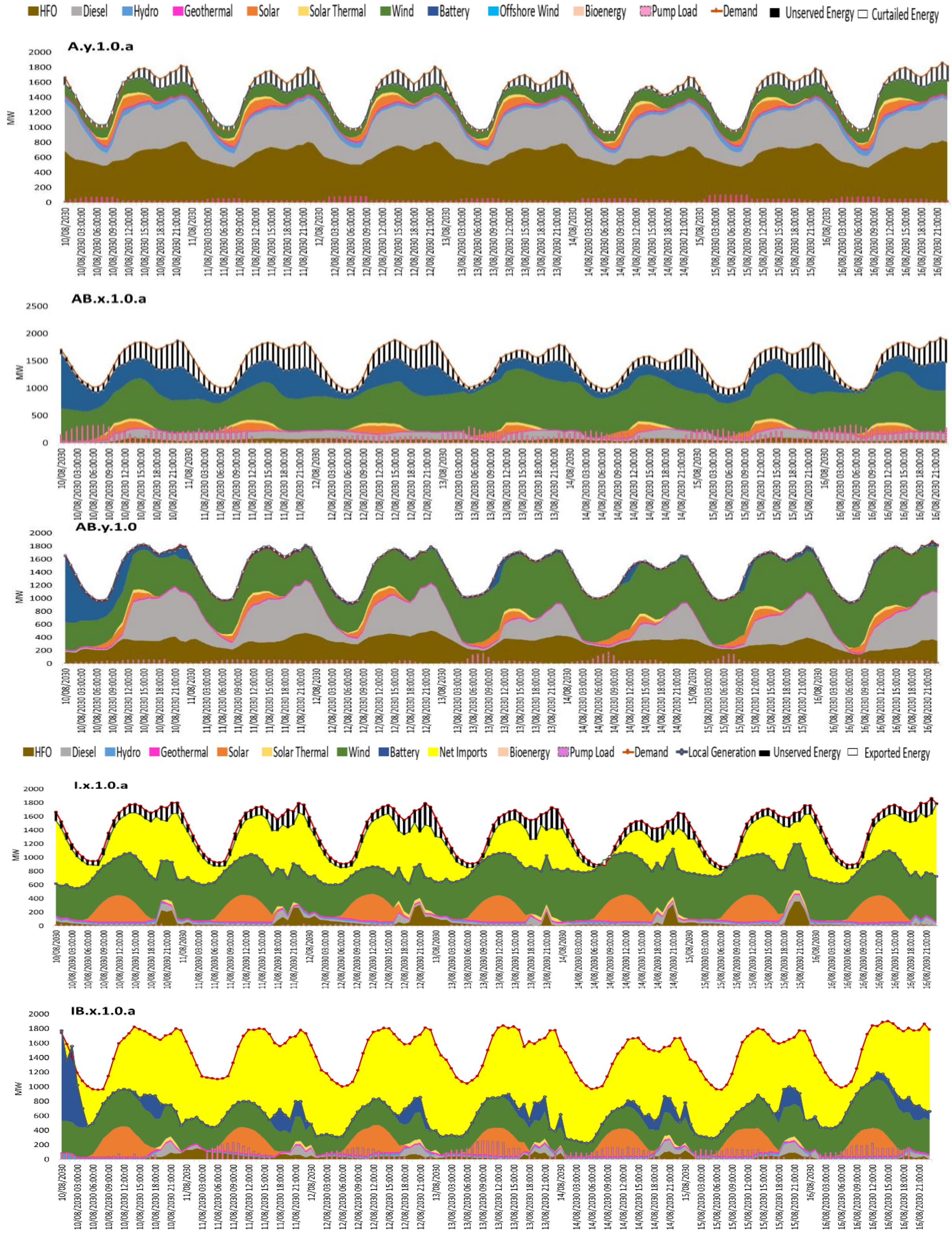


Figure 5.4: Representative weekly electricity hourly dispatch in the Greek islands region for 2030 - Maximum load week

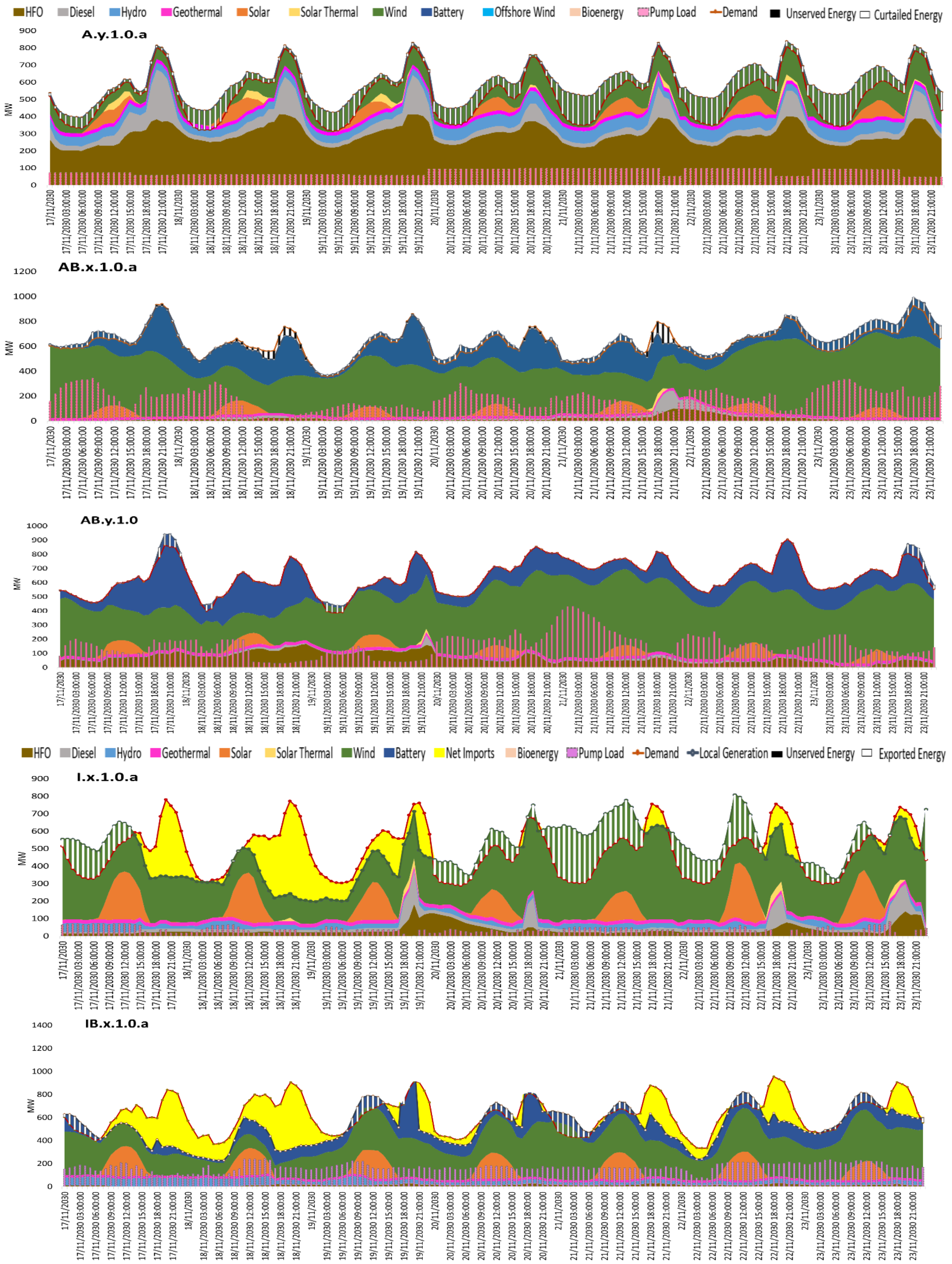


Figure 5.5: Representative weekly electricity generation hourly dispatch in the Greek islands region for 2030 - Minimum load week

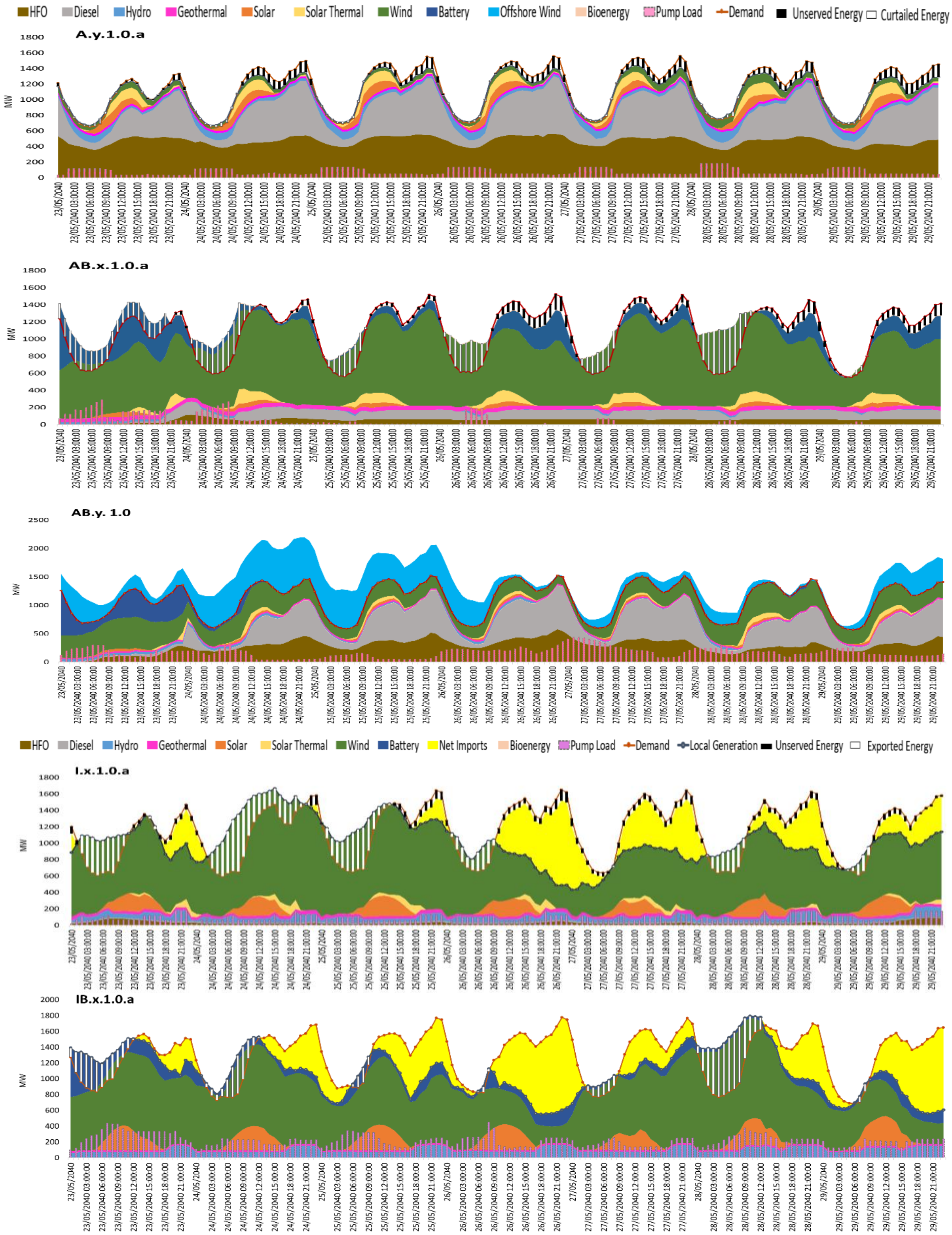


Figure 5.6: Representative weekly electricity generation hourly dispatch in the Greek islands region for 2040 - Average load week

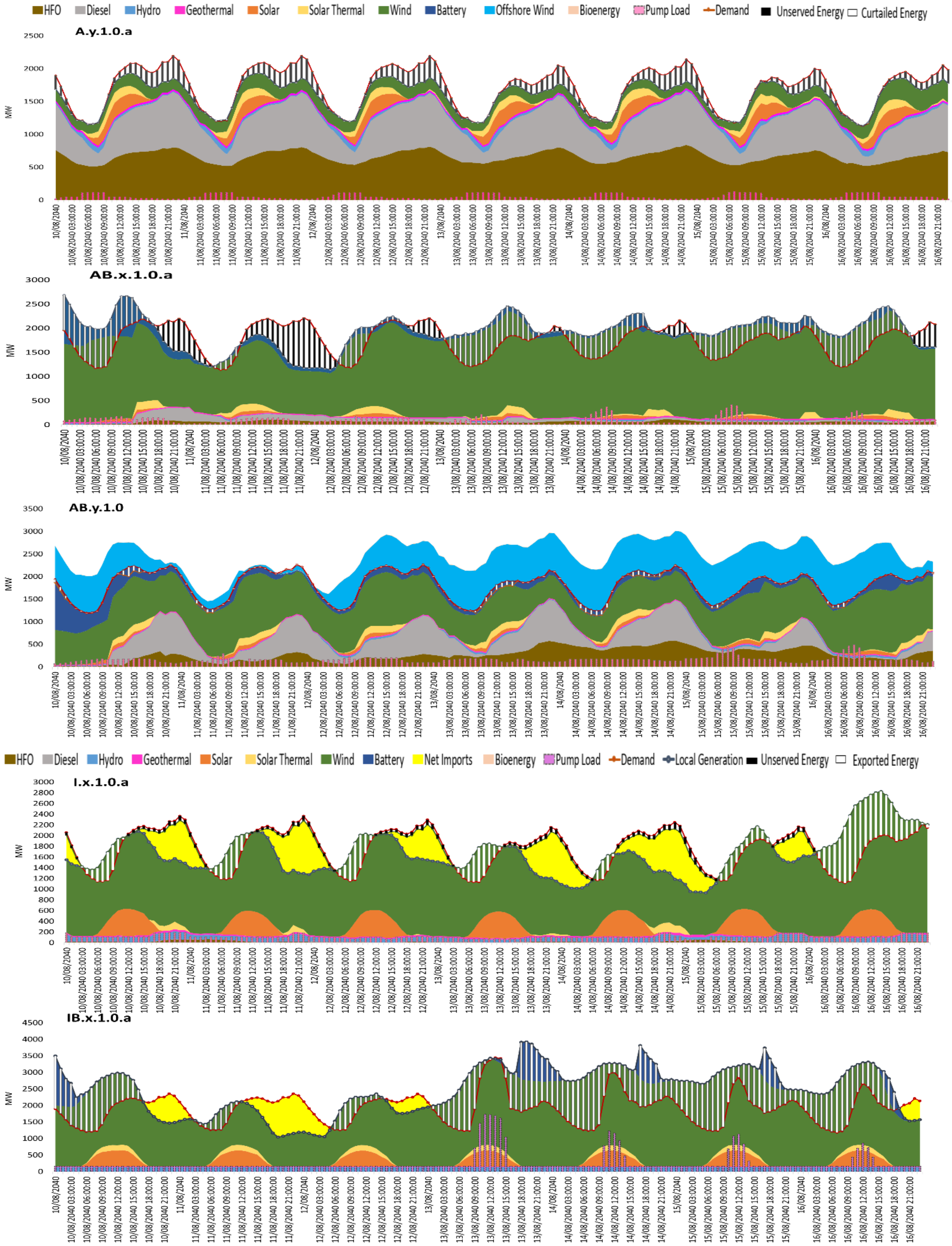


Figure 5.7: Representative weekly electricity generation hourly dispatch in the Greek islands region for 2040 - Maximum load week

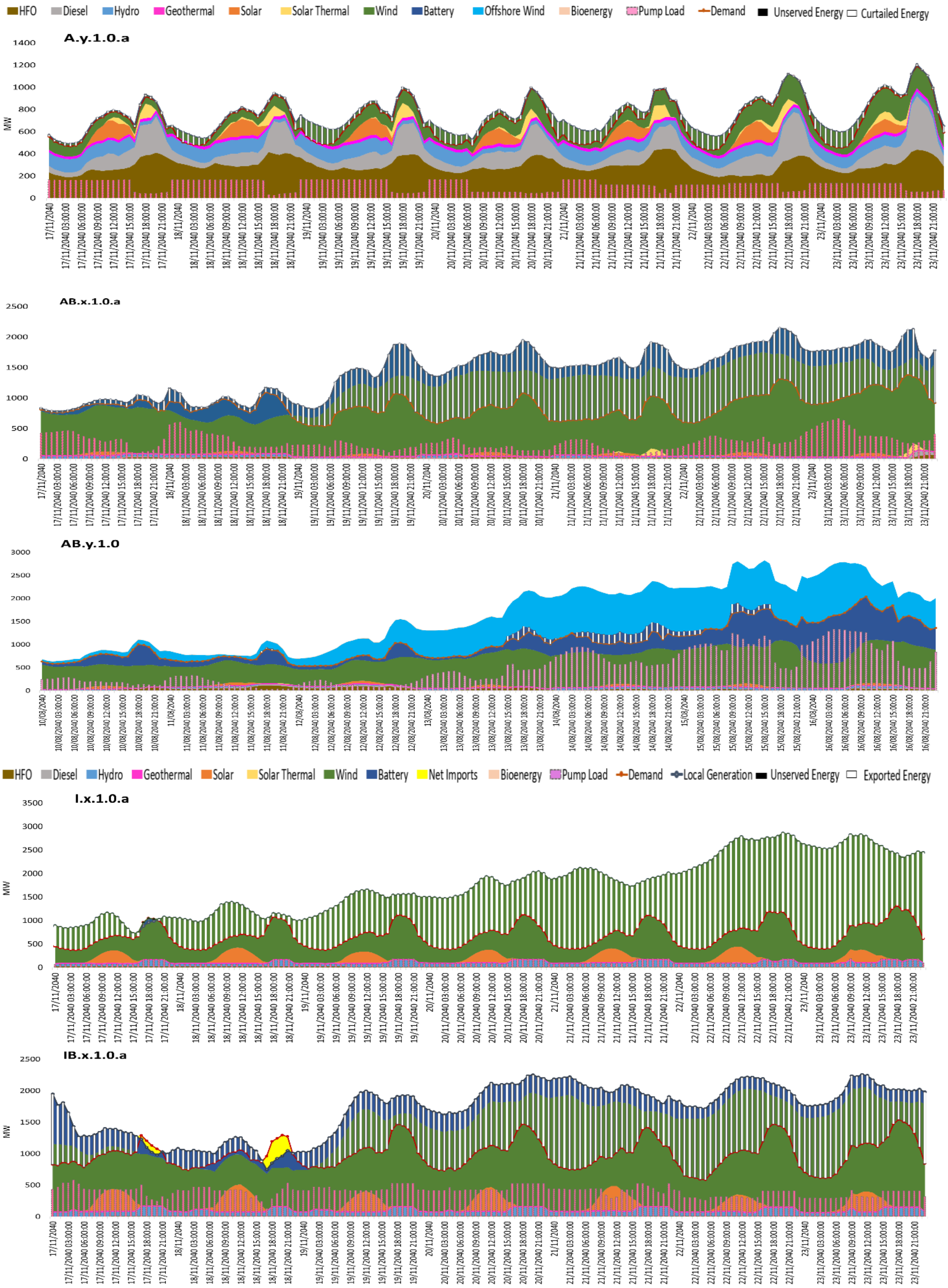


Figure 5.8: Representative weekly electricity generation hourly dispatch in the Greek islands region for 2040 - Minimum load week

5.2.3 System balancing and reliability

The system's reliability depends on local generation and transmission qualitative and quantitative characteristics such as the installed capacity, capacity factors, and planned and unplanned outages. Given the expected high penetration of renewables into islands' systems, the generation adequacy, reserve capacities, and frequency stability provided via ancillary services are investigated herein. In this respect, electricity systems need sufficient flexibility to address unpredictability in demand and generation. The LOLP indicator demonstrates the probability that demand will exceed the system's capacity in a given period considering parameters such as weather data, renewable and thermal generation, and forced outages as calculated in section 4.3.1. LOLP relies on the available reserve margin (%), as electrical systems with sufficient reserve margins have a low probability of demand exceeding generation. The available capacity reserves against the peak load reflected in the CRM, within a range between 15-20%, are considered adequate at the national level, with the Greek NGS currently recording a CRM of 45%. On the contrary, it has to exceed 50% in AES due to the lack of diversity in the electricity generation mix, while autonomous systems cannot import energy (North American Electric Reliability Corporation, 2013). Therefore, energy isolation leads to oversizing local generation capacity to secure the avoidance of power shortages.

In contrast with LOLP and CRM, which are long-term reliability indicators usually deriving from transmission and generation expansion planning, unserved demand is an outcome of short-term hourly dispatch modelling, indicating considerable losses not captured by the LOLP. Figure 5.9 and Figure 5.10 depict the long-term reliability performance of each island system under the four Principal Scenarios. NGS records have been excluded with zero levels of LOLP and sufficient CRM in all the scenarios.

In 2030, the Autonomous-Batteries Scenario (AB.x.1.0.a) demonstrates the highest CRMs exceeding 100% across almost the majority of the electrical systems, with average values at 350%. Such levels are anticipated as local generation is expected to meet the 90th percentile of peak demand through storage generation, leading to heavy investments in renewable capacity. Nonetheless, due to the increased intermittency of wind, unserved demand is recorded as mentioned below. The Autonomous (A.y.1.0.a) Scenario shows that a BAU projection will not display reliable operational island profiles for Crete, Paros, Rhodes, Lesvos, Milos and Patmos, demonstrating low generation capacity levels in parallel with relatively higher demand growth reflected in CRMs below 50%. Similarly, LOLP in most islands exceeds the accepted figures of 0.03% (representing approximately one day of power outage over ten years) (Hellenic Electricity Market Operator, 2019), with an average of 36%. The results show that AES have to secure higher firmed capacity levels, especially on Rhodes and Patmos but also on Paros and Crete electrical systems. In this respect, it is proved that most systems cannot meet the reliability threshold while continuing energy isolation unless they invest heavily in oil thermal power generators that would endure high costs.

The Interconnection Scenario (I.x.1.0.a) scores an average LOLP of 30% as certain firm capacity is replaced by renewables energy experiencing high generation unpredictability. The CRM is sufficient for the majority of the island systems exceeding 163% on average, except for Mykonos and Patmos, due to the relatively limited RES capacity deployed combined with the decommissioning of thermal capacity. The employment of BESS in conjunction with interconnections in IB.x.1.0.a provides an additional layer of security in the power system reflected in increased local CRM of 214% driven by additional clean energy capacity deployed. In parallel, the LOLP lowers to zero across all islands, except Crete, Paros, Mykonos and Samos, where limited impact is evidenced in terms of additional RES and storage capacity invested by that time.

By 2040, the AB.x.1.0.a scenario presents the highest local reliability with 0% LOLP and average CRMs of 240%, exceeding the 50% threshold across all island systems. On the other hand, the A.y.1.0.a scenario shows a higher probability of power shortages in most Cycladic and Dodecanese islands. These regions are expected to experience an increase in demand due to forecasted tourism growth without the analogous investments in thermal and renewable generation capacity. Exceptions are the Crete and the Northern Aegean Sea islands, which seem to operate adequately under a BAU case.

The Interconnection Scenario (I.x.1.0.a) significantly reduces regional LOLP in systems such as Crete and Paros, as additional generation capacity is built through 2030-2040. Others maintain LOLP at high levels as local thermal capacity decommissioning deteriorates reliability indicators even in periods with low demand. On the other hand, in the I.x.1.0.a Scenario, several electrical systems present CRMs below the approved levels, and occasionally negative figures are observed as almost the total local oil-fired capacity has been phased out by then while peak loads are expected to increase. The IB.x.1.0.a scenario achieves to significantly support the islands' systems while increasing the average CRM to 250% and reducing the average LOLP to 15%. Nonetheless, specific systems such as Mykonos, Patmos and Syros seem to score poorly for the same reasons discussed earlier.

The multi-regional LOLP concerning the Interconnection storyline significantly reduces load probabilities across all systems; however, the risk has not been outscored. Certain Dodecanese and Cycladic islands and Crete show a relative vulnerability, with LOLP ranging between 1% and 2% under the current interconnection plans. Specifically, for Crete island, the results show that to secure the continuous power supply on the island by 2030, when oil-fired generators are phased out, large-scale battery and pumped hydro systems need to be deployed. Alternatively, in conjunction with renewables, natural gas could balance Crete's system without abolishing emissions at the local level. In 2040, interregional LOLP is further reduced across the islands under the Interconnection (I.x.1.0.a) case, with the exception of Mykonos, Paros, Milos, Karpathos and Symi, where it is proved that the Cycladic and Dodecanese island complexes will require before 2040 reinforcement in their generation or transmission capacities. Finally, the IB.x.1.0.a scenario showcases zero multiregional LOLP indicators across the whole islands region, demonstrating the most energy secure principal scenario.

Unserved energy is represented as the percentage out of the annual system load, mainly dependent on regional demand, generation operational profiles, and weather conditions. The Autonomous-Batteries (AB.x.1.0.a) Scenario, despite the high levels of generation capacity, relies exclusively on intermittent resources and becomes highly volatile on weather conditions. Therefore, the largest contingency is related to variable renewable energy sources, threatening the reliability of the local system with systematic power cuts. Practically, the autonomous systems record annual shortages ranging between 0 and 25% of their annual demand, with an average value of 10% in 2030. Nonetheless, even though medium and large-sized autonomous systems cannot rely exclusively on battery storage, smaller systems with an annual peak demand of <6 MW could eventually become 100% RES without their interconnection to the NGS. Such examples are Agios Efstratios, Milos, Serifos, Antiparos, Folegandros, Nisyros, Oinouses, Pserimos, Symi and Telos. In the BAU Autonomous case (A.y.1.0.a), small unserved demand shares are recorded in 2030 close to the present values. Under the Interconnection Scenario (I.x.1.0.a), the unserved demand shares rise by an average of 5.6%. The area with the most extensive and most severe incidents in terms of duration and intensity is the Dodecanese region, with an average value of 14%. The complexity of the Dodecanese electrical system lies in its remoteness, the number of islands, and increasing demand. The absence of dispatchable capacity in parallel with high contingency risks and exceptionally steep demand peaks during the summer severely impacts the reliability of the neighbouring interconnected islands. Assuming the support of BESS, the unserved demand incidents are eliminated across all systems.

Power shortages continue over 2040, with similar absolute values considering the Autonomous-Batteries Principal Scenario (AB.x.1.0.a), which leads to lower rates (%) as load increases. Regarding the BAU (A.y.1.0.a), unserved demand increased to almost 7% compared to 3% in 2030. The island systems suffering the most are Crete, Serifos, and most of the Dodecanese Islands except for Rhodes. Under the Interconnection Scenario, the mean regional reliability is improved to almost 4% while it becomes evident that the Cycladic region becomes the weakest link, where local capacity cannot suffice the demand, which shows the failure to balance successfully demand and supply in the region while relying on imports from the continental part of central Greece which is the major electricity consumer in Greece. The introduction of BESS when submarine interconnections are installed in the IB.x.1.0.a eliminates uncertainties and risks associated with managing demand and supply, resulting in zero unserved demand.

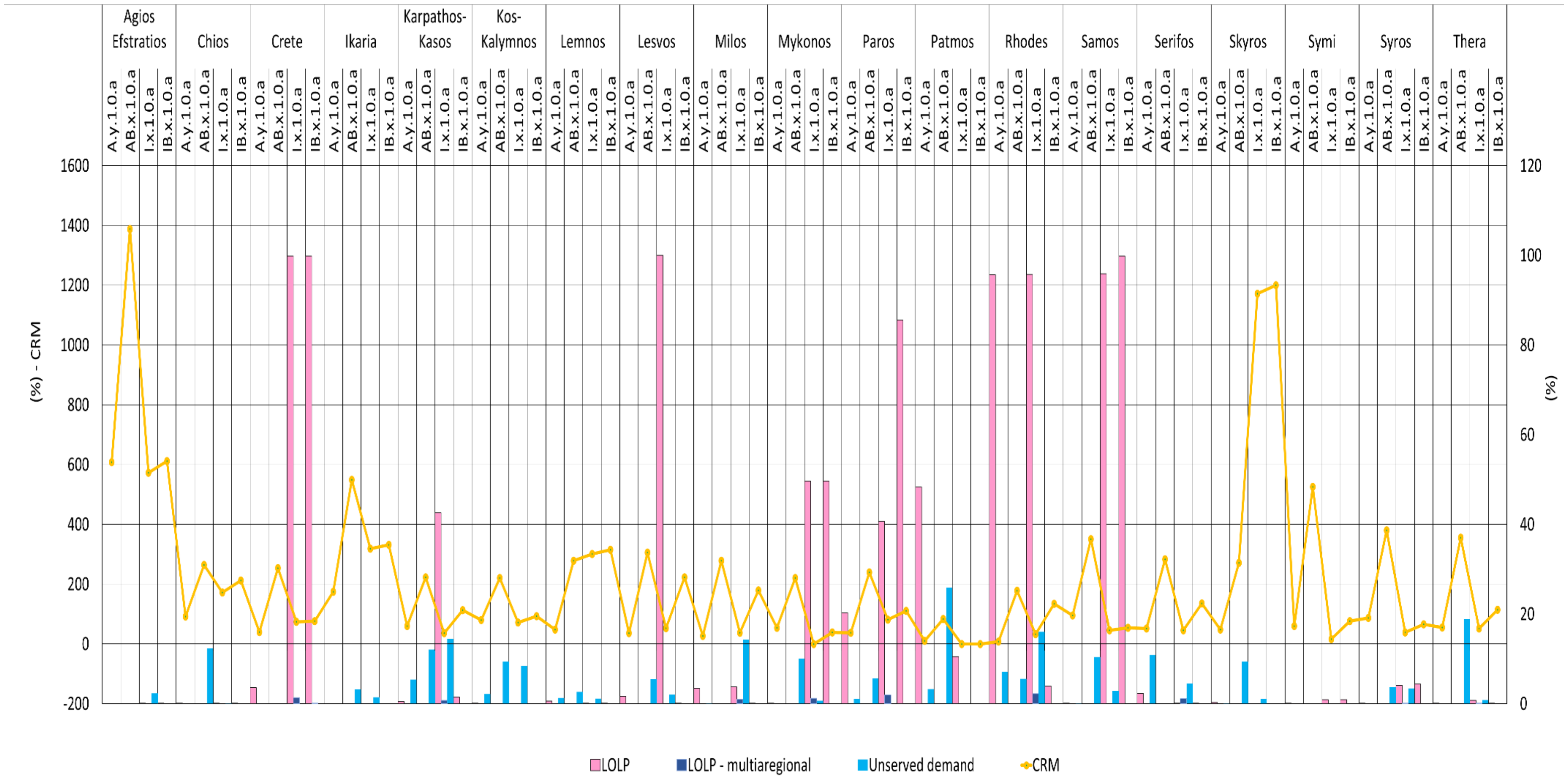


Figure 5.9: Regional CRM, LOLP and unserved energy for 2030 - Principal scenarios

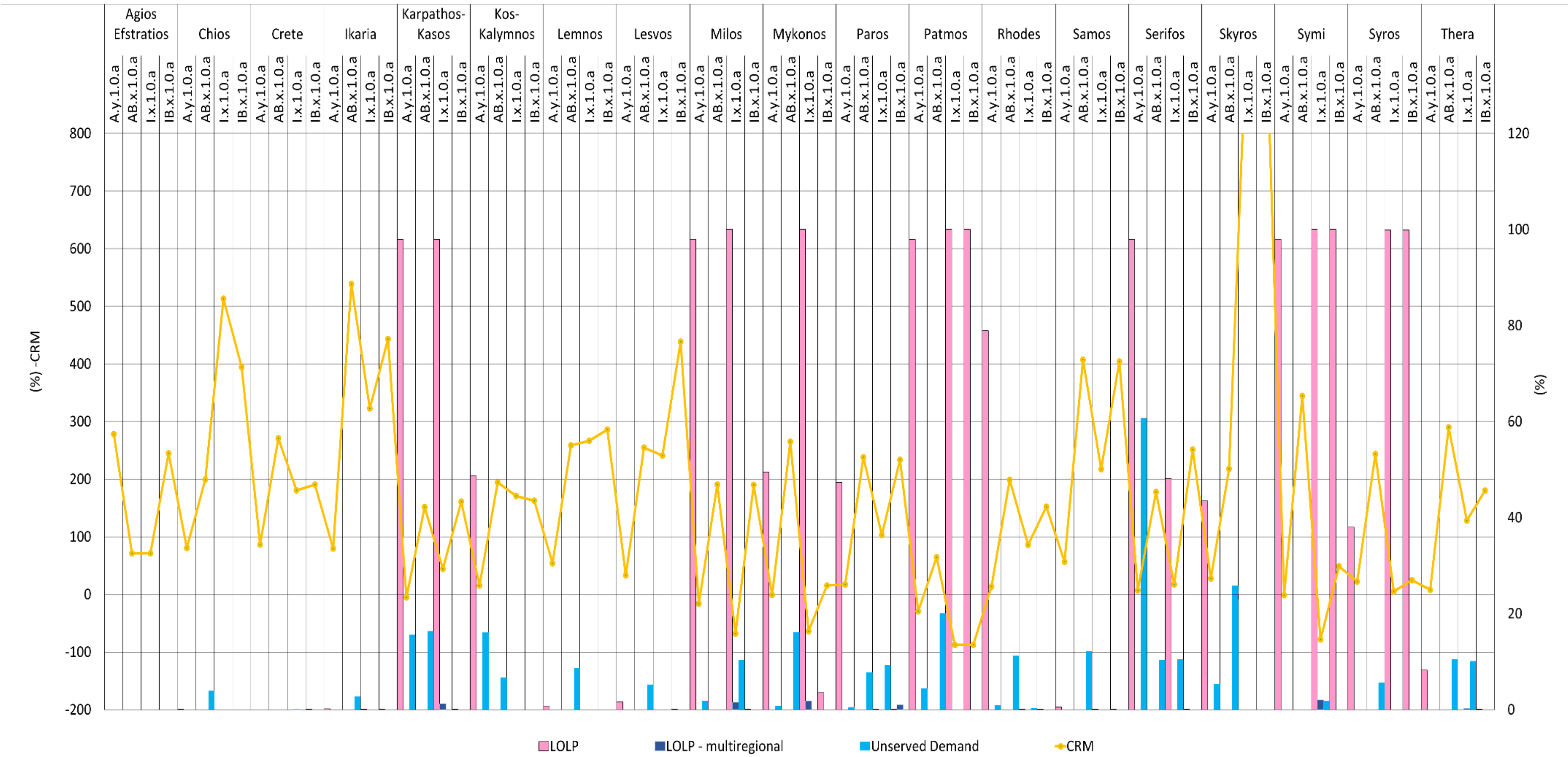


Figure 5.10: Regional CRM, LOLP and unserved energy for 2040 - Principal scenarios

5.2.3.1 *Sensitivity analysis*

Unserved demand and curtailed energy, considering the whole range of the explored scenarios for the Greek electricity system, are depicted in Figure 5.11. It becomes evident that the highest unserved demand is recorded in the Autonomous Pathway, assuming that generation restrictions are imposed in oil-fired generators (i.e., A.x. scenario). In particular, considering a scenario where renewables are not peaking up while local thermal generation is hampered (A.x.2.0), unserved loads reach 37% of the total demand in 2030 and 38.5% in 2040. Continuing in a BAU pathway where no generation restrictions are imposed (i.e., A.y.), unserved demand is reduced below 5%. Under the Autonomous case, in 2030, the power shortages are recorded mainly on Crete and Rhodes as the largest autonomous systems with increasing annual demand. Energy efficiency improvements are assumed under the High_Eff ISLA_EGI scenario in A.y.1.2.a assist in reducing unserved energy by 0.7% with similar figures for the A.y.1.2.b. Compared to the BAU demand scenario, the autonomous energy-intensive scenario reflected in A.y.1.1 employing Low_Eff demand projections would trigger additional undeserved loads by 1%. By 2040 the gap is increased to 1.3% between the High_Eff and the BAU scenario, while the Low_Eff continues to record additional unserved energy of almost 1%.

The AB pathway records higher unserved rates than the Autonomous (A.y.) for 2030, ranging between 4 and 14% of the total demand, while by 2040, they decrease to 1-5%. On the contrary, the AB.y.1.0 scenario without generation restrictions records zero unserved demand. Considering the interconnection scenarios in 2030, the average unserved energy still ranges between 0 and 9%. It is observed that under such a case, unserved demand is considerably reduced over time to eventually 0-1.5% in 2040, as the local system is supported further by new generators. The implementation of ambitious energy efficiency measures under the High_Eff scenario combined with submarine interconnections in I.x.1.2.a shows that the unserved demand rate can go as low as 0.15% in 2040. The interconnection scenario supposing no generation restrictions (I.y.1.0) and the pathway coupling batteries and interconnections (IB.) show zero unserved energy benefiting from dispatchable generation regulating the local demand and supply effectively. If NG is introduced to Crete combined with interconnection (I.x.1.0.f), load shedding is reduced to 1.5% in 2030 and 0% in 2040.

Curtailed loads concern primarily wind being the most volatile energy source. They are primarily present in those scenarios supposing oversized RES capacity to meet the annual demand peaks (i.e. A and AB pathways). Usually, such systems aim to fill the demand gap resulting from generation restrictions by investing heavily into thermal capacity, which operates with a capacity factor of 5.7-17.2%. The endeavour to build a reliable autonomous system depending entirely on RES, results in curtailments of 2.5% in 2030 and up to 4% in 2040. On the contrary, the Interconnection scenarios eliminate curtailments caused by overgeneration, which cannot be absorbed. Exceptions are the High_Eff demand scenarios I.x.1.2.a and I.x.2.1.b as they record lower demand levels. Especially the latter one builds additional renewables due to the increased carbon taxes assumed, resulting in 2.5% and 4.3% of curtailed power, respectively.

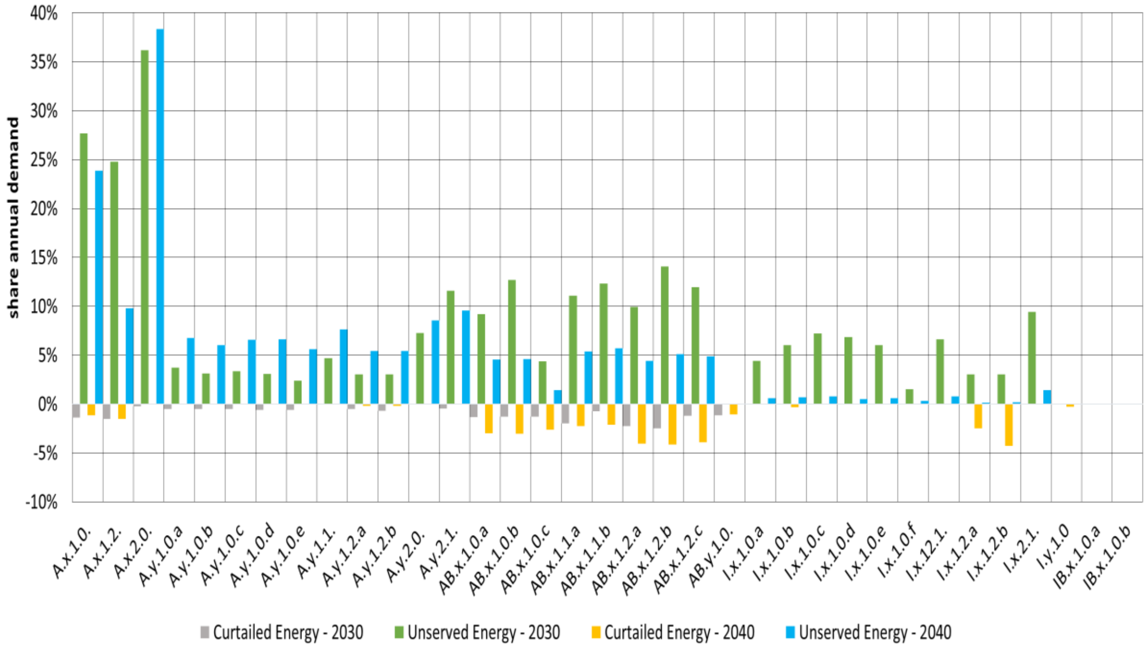


Figure 5.11: Unserved and curtailed energy across scenarios in the Greek islands' region – Sensitivity analysis

The impact of RES integration in reducing unserved demand is illustrated in Figure 5.12. The two main pathways presented are the Autonomous and the Interconnected, exploring the impact of balancing demand and supply while introducing RES coupled with the local thermal generation or optimally submarine grid extensions. In the Autonomous Pathway, a pattern is evidenced, showing that unserved demand continues to increase in time as there are no practical alternatives to fill the demand gap. Notably, reducing RES from 1.1 GW to 0.8 GW increases power shortages by 44% in 2030 and 11% by 2040, i.e., 700 GWh compared to 630 GWh in the original scenario (A.y.1.0.a). On the other hand, adding an additional 500 MW to 1.6 GW of RES can reduce unserved demand by 55% in 2030 and 21% in 2040, i.e., 495 GWh.

In the Interconnection Scenarios, the unserved energy peak is reached in 2030, while following the completion of the whole interconnection project in the islands region, RES deployment increases. The lowest unserved demand is recorded when 5.3 GW RES are deployed. It is worth noticing that by reducing local RES capacity to 4 GW, load shedding increases by 38% in 2030, going from 330 GWh up to 536 GWh, while in 2040, the gap is reduced from 80 to 140 GWh. A further reduction to 2.6 GW, which implies underutilisation of the submarine infrastructure, would end up to an almost 100% increase, translated into 654 GWh of power interruption in 2030 and 343 GWh in 2040 recording a fourfold increase.

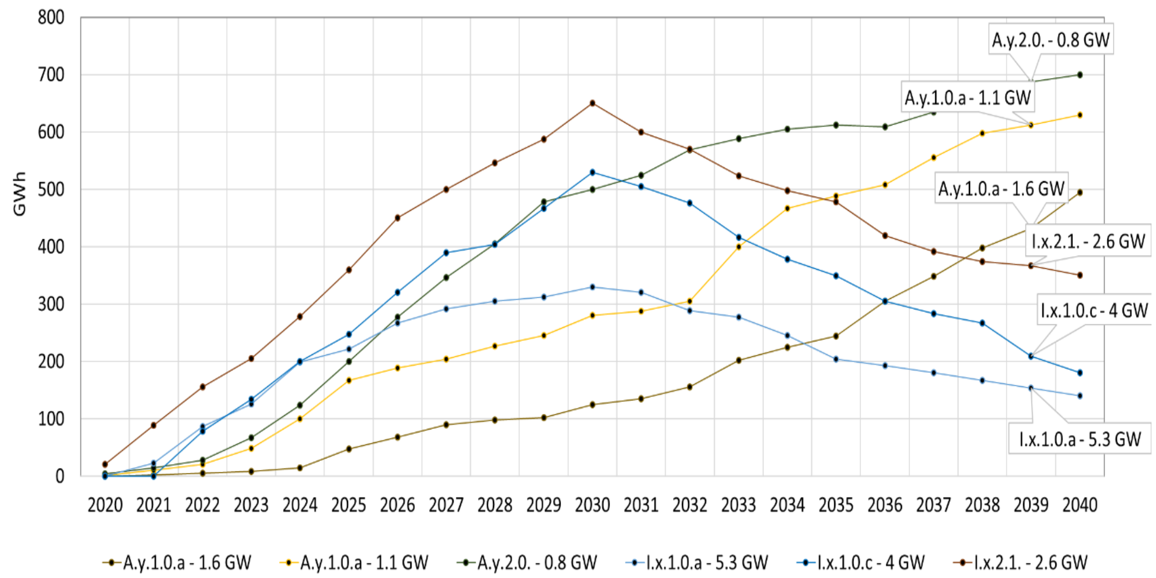


Figure 5.12: Unserved demand under various RES integration scenarios

5.2.3.2 *Seasonal variability*

Planned and forced outages play a vital role in configuring regional reliability. Maintenance is proportional to the size of generation capacity and, as anticipated, is increasing between 2030 and 2040. Maintenance is usually scheduled to avoid peak load times and therefore reduce the impact on the system, therefore taking place mainly during autumn and spring months. Over those periods, the highest maintenance factors range between 37.8 MW for the Interconnection and 73 MW for the Autonomous Batteries Scenario in 2030, increasing up to 160 MW in 2040, according to Table 5.1. Regarding transmission maintenance, it takes place every two years. As a highly volatile type of infrastructure, submarine cables are scheduled to undergo maintenance between January and April and between October and December. While generation maintenance is scheduled optimally by PLEXOS, transmission maintenance is treated as modelling input.

Forced outages are unplanned outage events that cause the most extensive disruption in the system. They are random, and under this research, they have been calculated using Monte Carlo simulation (Section 4.4.1). While maintenance events are excluded from the formula calculating power shortages, forced outages are considered when calculating reliability indices due to their randomness. Table 5.2 displays no consistent pattern in forced outages among the seasons, especially concerning wind, which usually records such events during periods experiencing the highest capacity factors. In general, the Autonomous scenarios employing BESS experience higher forced outages reaching up to 546 MW in 2040 due to the region's massive scale-up of renewable energy capacity.

Table 5.1: Planned outages (maintenance) of generation & transmission capacity per representative week

Generation Maintenance (MW)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	424	43.4	41.3	42.4	61.4	61.6
AB.x.1.0.a	66.6	73	65.1	66.6	160.11	116
I.x.1.0.a	27.3	37.8	18.5	27.3	73	45.5
IB.x.1.0.a	24.3	36.5	19.9	24.3	63.7	62.1

Transmission Maintenance (MW)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	N/A	N/A	N/A	N/A	N/A	N/A
AB.x.1.0.a	N/A	N/A	N/A	N/A	N/A	N/A
I.x.1.0.a	106	511	350	0	359.7	98
IB.x.1.0.a	0	256.7	87.9	0	0	150

Table 5.2: Forced outages of generation & transmission capacity per representative week

Generation Forced Outages (MW)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	15.76	45.18	24.34	29.6	64.2	49.71
AB.x.1.0.a	348	74.24	148	209	546	150

I.x.1.0.a	60	51	75.82	216	216.5	192.2
IB.x.1.0.a	444	264	51.3	193	203	253

Transmission Forced Outages (MW)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	N/A	N/A	N/A	N/A	N/A	N/A
AB.x.1.0.a	N/A	N/A	N/A	N/A	N/A	N/A
I.x.1.0.a	0	150	1108	5	1002	0
IB.x.1.0.a	496	250	150	250	350	650

Seasonal variability is represented in Table 5.3 through the following reliability indicators LOLP, LOLE, and EENS. The results show that during the summer months, when demand is three times higher than in the winter, LOLP is increasing to 33% in 2030 under the interconnection pathway. By 2040, the highest volatility is observed in the Autonomous scenario, with 63.2%. LOLP has a temporal dimension represented through LOLE. The average regional hourly LOLE increases significantly between 2030 and 2040, recording approximately 24 seconds per hour under I.x.1.0.a. The highest risk is during evening hours 18:00-22:00 when demand is soaring and there is no contribution from solar energy. During these periods, demand-side management or storage in IB.x.1.0.A could contribute effectively to peak shaving, reducing to 6% the LOLP in 2030 and 11.5% in 2040; however still above the approved threshold. The employment of energy efficiency measures for reducing demand in I.x.1.2.a could further reduce LOLP by 10%.

While LOLP declares the probability of power outage and LOLE the duration, EENS is the expected energy not supplied, showing the intensity of the incident. Despite increasing its local thermal capacity, the Autonomous scenario is likely to record frequent power outages over the summer months as demand related to tourists' arrivals grows uncontrollably. As such, A.y.1.0.a, followed by I.x.1.0.a, record the highest EENS exceeding 100 MWh/h during summer.

As previously explained, regional figures for reliability indicators under the interconnection scenarios have little impact as they include a zero-interconnection capacity. However, subsea interconnections among the Greek islands have been designed to respect the N-1 criterion. Even under a total failure, a transmission line continues supplying power to the island, temporarily securing the system's smooth operation. The system is tested by enforcing the N-1 rule, assuming that specific transmission capacity is set to zero. The results show in Table 5.4 that interconnections exhibit mostly zero multi-regional reliability indicators. On the other hand, summer peak loads in I.x.1.0.a showcase volatility.

Table 5.3: Average hourly regional reliability indicators per representative week

Average LOLP (%)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	13	0.011	14	63.2	5.3	6.3
AB.x.1.0.a	0.09	0	0	0.15	0	0,02
I.x.1.0.a	33	0.73	15.92	42.1	26	36.85
IB.x.1.0.a	6	0.35	0.3	11.5	0	6.56

Average LOLE (min/day)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	7.2	0	7.9	36	3.17	3.6
AB.x.1.0.a	0	0	0	0	0	0
I.x.1.0.a	18.7	0.36	9	20.8	14.4	23.8

IB.x.1.0.a	3.6	0	0	6.5	3.6	3.6

Average LOLE (min/day)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	7.2	0	7.9	36	3.17	3.6
AB.x.1.0.a	0	0	0	0	0	0
I.x.1.0.a	18.7	0.36	9	20.8	14.4	23.8
IB.x.1.0.a	3.6	0	0	6.5	3.6	3.6

EENS (MWh)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	42.98	0.0355	0.39	109.41	3.37	1.27
AB.x.1.0.a	0.8	0.01	0	0.1	0	0
I.x.1.0.a	83	0.34	68.28	101	27	72
IB.x.1.0.a	2.75	0.88	1	21.74	12.81	9.92

Table 5.4: Average hourly inter-regional reliability indicators per representative week

Multi-regional LOLP (%)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	N/A	N/A	N/A	N/A	N/A	N/A

AB.x.1.0.a	N/A	N/A	N/A	N/A	N/A	N/A
I.x.1.0.a	0.28	0	0	0.11	0	0
IB.x.1.0.a	0	0	0	0	0	0

Multi-regional LOLE (MWh)						
	2030 Max	**2030 Min**	**2030 Avg**	**2040 Max**	**2040 Min**	**2040 Avg**
A.y.1.0.a	N/A	N/A	N/A	N/A	N/A	N/A
AB.x.1.0.a	N/A	N/A	N/A	N/A	N/A	N/A
I.x.1.0.a	0	0	0	0	0	0
IB.x.1.0.a	0	0	0	0	0	0

5.2.3.3 *Ancillary services provision*

As the max provision depends mainly on the local thermal generation in the islands' region, the BAU Autonomous Scenario (A.y.1.0.a) records relatively lower risk levels, translated into low local reserve requirements (Figure 5.13). The Autonomous-Batteries (AB.x.1.0.a) scenario experiences 30 to 50% higher risk for lower, raise and regulation provision requirements compared to the BAU Autonomous case A.y.1.0.a., whereas in 2040, the gap increases to 35 - 60% ranging between 3,000 and 4,000 GWh. This is attributed to replacing the contingency generator with large-scale hybrid battery-wind farms deployed on the islands. Under the Interconnection scenario, the risk is reduced to 1600 GWh as local renewable energy expansion is regulated compared to the AB pathway. If batteries are employed in IB.x.1.0.a, the risk is further reduced to 900 GWh for raise and lower reserves. Spare capacities reserve requirements are directly linked with the units committed, fluctuating according to the largest contingency generator, showcasing a much higher risk under the Interconnection scenarios due to decommissioning existing oil-fired generation to provide replacement services.

Through time, there is a 20-30% increase in regional raise and lower reserve risk concerning the Autonomous scenario attributed mainly to static and load risk growth and replacements in the contingency generators with larger ones. The Autonomous-Batteries scenario sees an increase ranging between 20 and 40% aligned with the installation of RES capacity. Such requirements are also directly linked to the decommissioning of thermal units that cannot provide lower or raise services but only tertiary, as they are not committed. The Interconnection scenarios (I.x.1.0.a and IB.x.1.0.a) record a negligible fluctuation concerning the raise and lower reserves between 2030 and 2040 since interconnection capacities allow for reserves sharing across the network. Due to oil-fired generation restrictions following the interconnections, certain capacity is phased out or operating at their minimum, resulting in reserve shortages. In I.x.1.0.a, the incidents of lack of available reserve capacity for lower response in 2030 is 832 GWh while it lowers down to 554 GWh if battery storage is added. As anticipated, concerning raise and regulation services due to lack of sufficient dispatchable capacity, up to 1,850 GWh of reserves shortage is recorded, reduced to 20 GWh in the IB.x.1.0.a scenario. In the Autonomous-Batteries case (AB.x.1.0.a), no reserve shortage is experienced due to the large capacity of BESS participating in the reserve share. In 2040, shortages are drastically reduced to zero if storage and interconnection infrastructure are combined in the IB.x.1.0.a scenario. On the other hand, in the I.x.1.0.a interconnection scenario, lower and raise shortages remain at high levels.

Once interconnected, the reserves sharing option is enabled, allowing NGS to provide balancing services to the islands' region and vice versa. Therefore, the risk, including all types of ancillary services except the lower in the mainland, is lessened according to Figure 5.14. The vulnerable category for reserves provision is the replacement. It is also interdependent to lignite-fired production, estimated to become completely phased out by 2028 under most scenarios; therefore, 4,370 GWh of shortage is recorded across the Autonomous pathway, which is preserved in 2040.

Costs spent in the ancillary services market are proportional to the reserve provision requirements, with the AB.x.1.0.a scenario recording 165€ million in the ancillary reserves market in 2030 and 212€ million in 2040. The costs are significantly reduced across the other scenarios, with the interconnection involving 21€ million in 2030 and 40 € million in 2040.

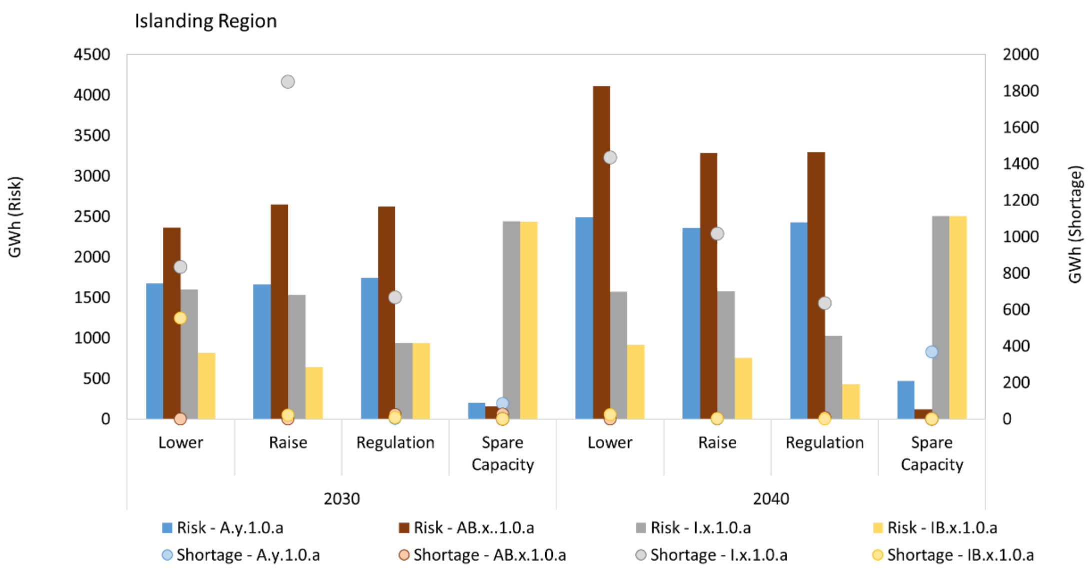


Figure 5.13: Annual ancillary services risk and shortage for the islands' region - Principal scenarios

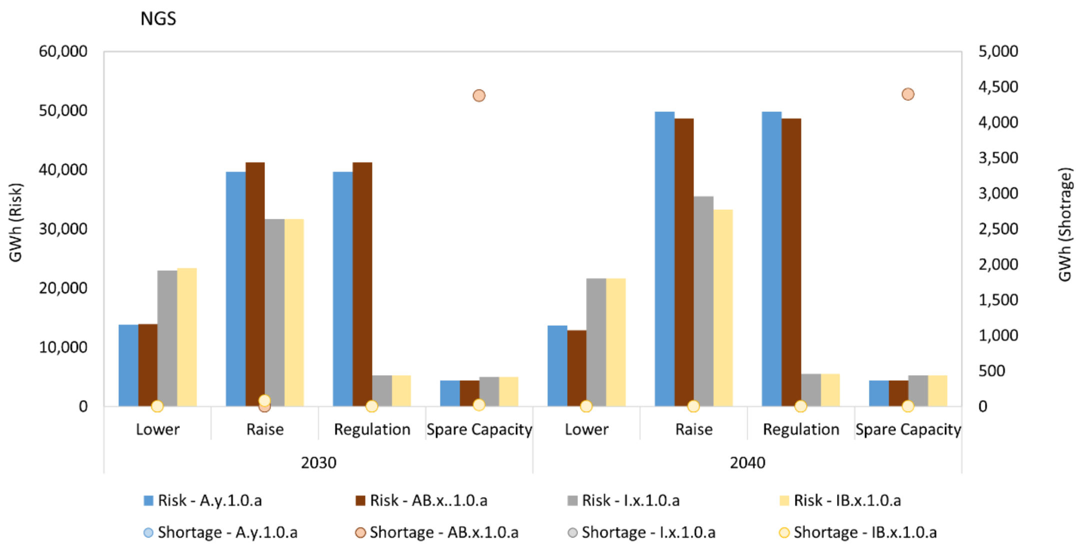
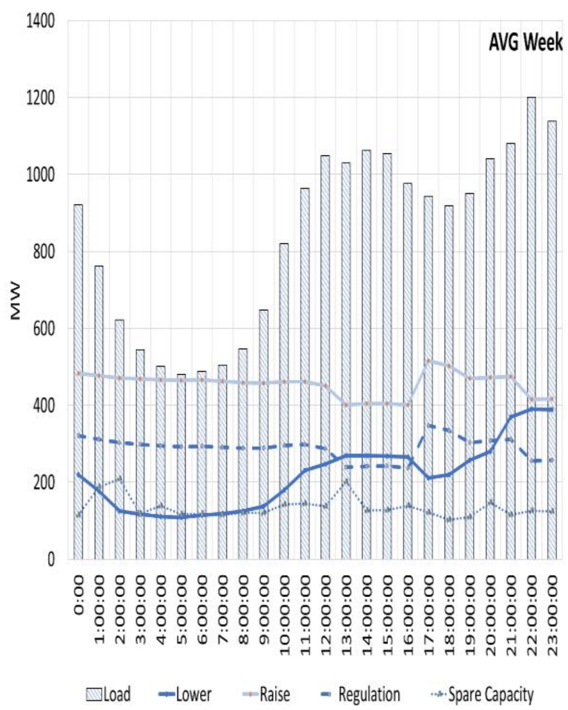
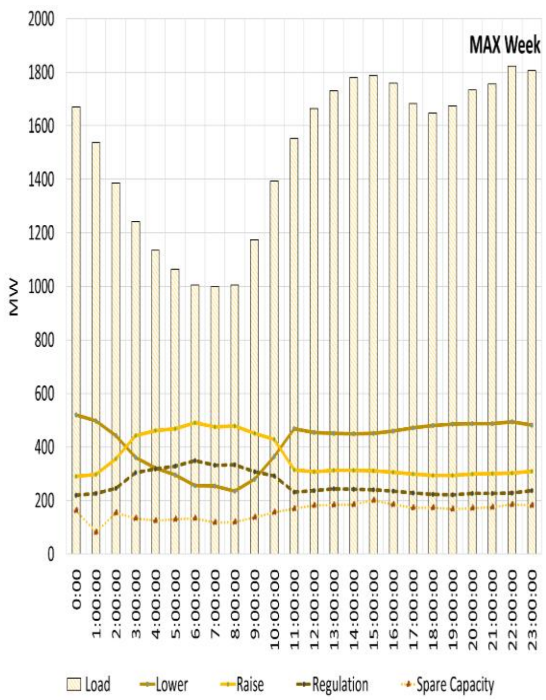


Figure 5.14: Annual ancillary services risk and shortage for the Greek NGS - Principal scenarios

Seasonal and hourly variations prove that the period showcasing the highest reserves capacity requirements is summertime (MAX week), when demand and renewable energy generation record their highest peaks compared to the rest of the year (Figure 5.15). On the other hand, as load risk reduces during spring, autumn (AVG week) and wintertime (MIN week), reserves for ancillary services reduce simultaneously. Across the day, downward services increase availability during high demand due to the large number of units being committed to dispatching. Therefore, operational plants are available to lower their capacity due to unexpected requirements for lower services. This usually overlaps when the largest wind combined with solar generation is dispatched from 9:00 in the morning until evening. Spinning and regulation services fluctuate over the year, usually available to supply raise services when demand peaks are forecasted. During the maximum load weeks, the available generation is usually insufficient to meet demand while recording shortages during the peaks; therefore, the capacity to provide reserves is limited. Spare capacity requirements fluctuate over the day, showing that additional capacity is dispatched to cover loads in the minimum week over the evening hours with a higher margin for lower reserves provision. In general, during the minimum and average weeks, the load profiles shift as the consumption pattern differs, demonstrating that the highest hourly risk is usually during times of high-RES dispatch.





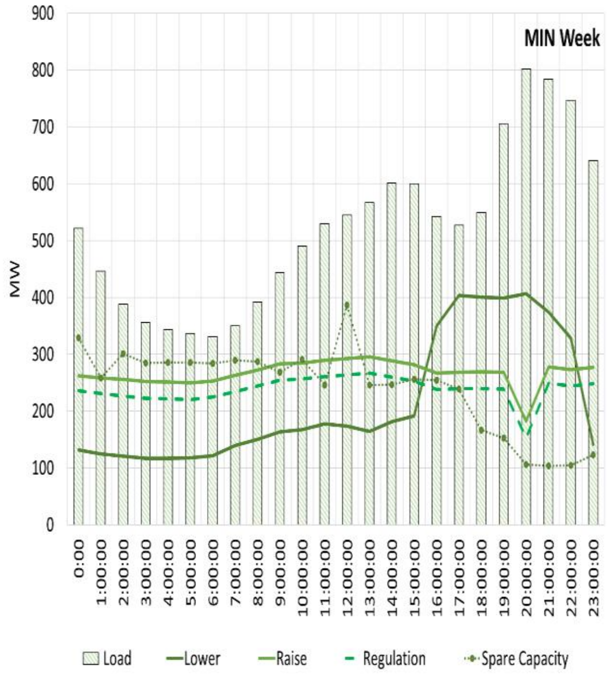


Figure 5.15: Seasonality and hourly variability of ancillary reserves provision in the Greek islands' region per representative week

5.2.4 Interconnectivity and power flow exchange

The annual regional interchange, which is the sum between imports and exports for 2030 and 2040, is depicted in Figure 5.16. The analysis proves that power flows intensity and intermittent renewable energy generation are correlated. It is evident that in 2030, the NGS mainly exports power to newly interconnected regions with the IB.x.1.0.a scenario producing lower power flows by 15% in 2030 compared to I.x.1.0.a, despite a slight increase in imports, owing to the efficient system balancing. The majority of the islands are experiencing net imports except for the small island of Skyros, directly interconnected to the mainland, with more than 333 MW wind onshore installations, flowing most of the generation to the mainland.

By 2040 the overall number of flows is almost equalised between the two scenarios since BESS supports the addition of 560 GWh compared to the Interconnection Scenario despite the peak shaving and valley filling services. As the power flows balance reverts, NGS becomes a net importer of clean energy produced in the islands' region, primarily from islands such as Crete, Chios, as well as Lemnos and Agios Efstratios hosting wind offshore farms close to their coast. Despite the considerable increase in local RES generation, islands such as Milos, Thera, Syros and Mykonos still rely on the mainland's electricity imports to cover summer peaks. On Rhodes, regardless of the significant import reduction of up to 83%, the system remains energy dependable to Crete and the mainland. This creates vulnerability issues in the interconnected island network of Dodecanese islands. The replacement of the current scenario with a direct line between Kos and the central part of the Greek mainland (I.x.1.0.b) would reduce the region's exportable capacity; therefore, it is not recommended.

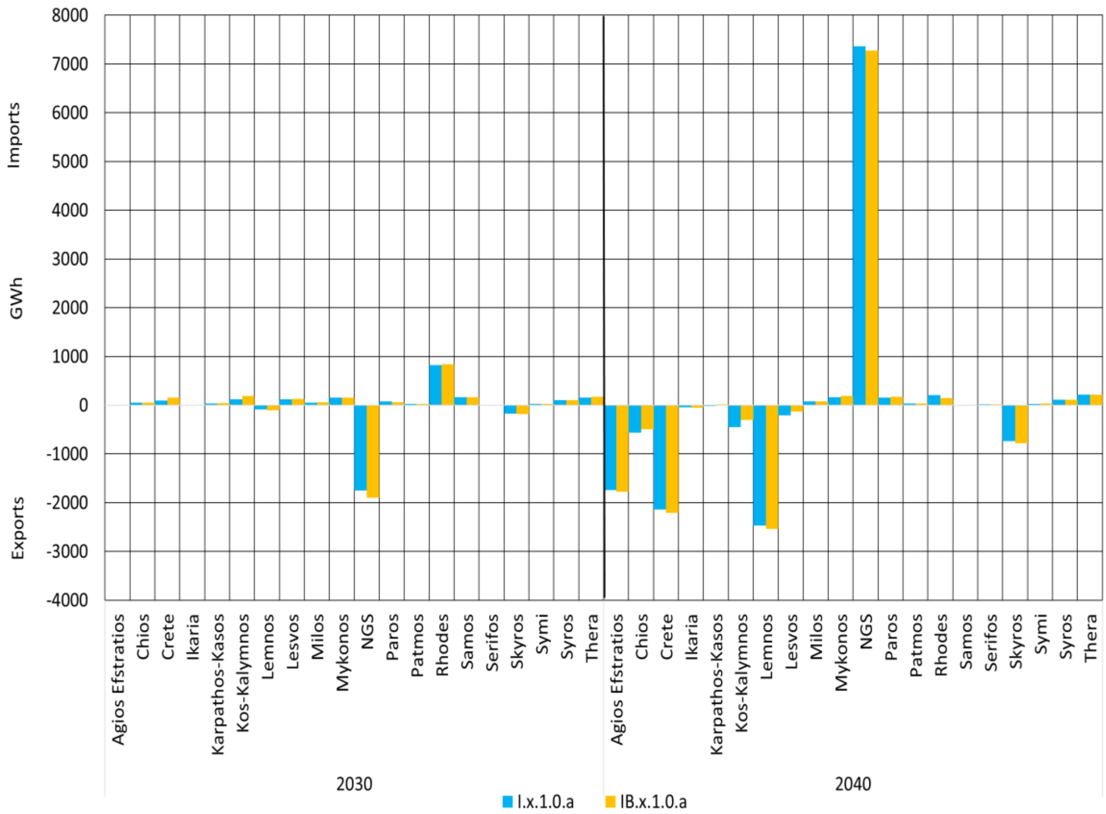


Figure 5.16: Regional electricity interchange in 2030 and 2040

5.2.4.1 *Short-term dispatch*

Figure 5.17 depicts the import and export balance seasonality during the three representative weeks in 2030. The interchange profile aligns with the demand profile, where imports increase over morning and evening peaks while being reduced overnight. Renewable investments are triggered by adding battery storage at the interconnected system (IB.x.1.0.a), leading to higher generation profiles able to cover local demand while eliminating unserved loads. To achieve this, local BESS require additional imported energy to charge the energy systems while balancing local and imported dispatch effectively. During the week recording the maximum load over the summer, the import graph records steep spikes and an unbalanced profile due to on-demand battery charging and discharging. Over the minimum week in winter, certain islands can export their surplus to cover demand in the Greek mainland, especially during evenings.

By 2040, the local renewable energy development allows for energy exports from the islands to the mainland, as illustrated in Figure 5.18. In the Interconnection Scenario (I.x.1.0.a), considering a week with moderate loads (AVG), there are 19 GWh exported to the NGS weekly, which corresponds to 10% of the local energy production. In IB.x.1.0.a exports are limited to 12 GWh with 44 GWh imports. During the max week under IB.x.1.0.a, we notice that the Greek islands' network will export 127 GWh to the mainland (45% of the local generation) due to frequent charging and discharging cycles and favourable weather conditions for solar and wind energy production. At the same time, solar power production increases over the summer months, and batteries signal charging during the morning hours to balance the supply. Batteries discharge during hours of lower available production while exporting flows towards the NGS. During winter, the islands' region exports 116 GWh of clean energy, which translates into 39% of the local generation. This amount is sufficient to cover 9% of the electricity demand requirements in the NGS. Despite the discrepancies due to scenario assumptions and seasonality, imports peak is mainly recorded during evening hours when demand increases.

Figure 5.17: Net hourly interchange between the Greek islands' region and the NGS for 2030 per representative week

Figure 5.18: Net hourly interchange between the Greek islands' region and the NGS for 2040 per representative week

5.2.4.2 *Congestion*

The increase in local electricity consumption can create congestion zones at some network routes. According to Figure 5.19 and Figure 5.20, several lines are congested, while in this study, only those lines exceeding 3,000 hours per year have been considered as severely congested (Di Cosmo, Bertsch and Deane, 2016). These incidents cause a non-optimal network operation (losses in transmission, an increase in operation cost, etc.) and may require a network upgrade. Flexibility in energy storage and demand management allows the avoidance of additional infrastructure investments. Furthermore, it enables to gain from load shedding benefits while keeping overall load and produced energy (Andrey *et al.*, 2016).

It is noticed that the lines connecting Lesvos to Agios Efstratios and Lemnos and the cables between Naxos and Mykonos as well as Crete to Peloponnese experience congestion incidents reaching or exceeding 4,500 hours by 2030, escalated to 6,700 hours in 2040. These events signal new transmission capacity or a more effective demand and supply management using BESS and demand-side management. The lines connecting Lesvos, Agios Efstratios and Lemnos are utilised to transmit energy from Evia island to the northern part of the North Aegean region, with limited touristic interest but high-RES potential, which results in export loads. The results prove that the 140 MVA cable has been undersized. In this sense, it is recommended to increase its capacity to reach 280 MVA or install a third cable to be fully exploited following 2040. Alternatively, BESS could support the local systems in reducing congestion levels and limiting losses. On the other hand, the northern part of North Aegean and the Dodecanese region present no congestion issues.

The line between Naxos and Mykonos is congested as Naxos and Paros are supplying power to Mykonos. If BESS are employed, Mykonos will increase its power generation by 113 GWh, relieving the congestion phenomenon in the Naxos-Mykonos line allowing for transmitting power smoothly between the islands of Thera, Mykonos, Naxos and Paros. The low power flow levels in the cables in the Cycladic islands (Folegandros-Milos, Milos-Serifos, Naxos-Thera, Syros-Mykonos and NGS, Thera-Folegandros) highlight that most of the generation produced in the Cycladic region is consumed internally until 2030, while the cables operate mainly for import purposes instantly. By 2040, cables interconnecting the Western Cycladic islands (i.e., Milos, Serifos & Folegandros) remain underutilised; therefore, their capacity could be scaled down. A satisfactory level of capacity utilisation of 70%, which respects operational security limits and takes into account contingencies, has been incorporated (European Commission, 2018a). The line extension between Serifos and Lavrio is judged redundant unless it replaces the second submarine transmission line between Syros and the Greek mainland scheduled to take place in 2024. By 2040, RES capacity will increase on Crete, enhancing its self-sustainability, while the internal network between the western and central parts is reinforced. Also, the cable operation between Central Greece (NGS 2) and Crete has become more effective, reducing congestion incidents between the Peloponnese region (NGS 3) and the Western part of Crete. The model decides to build two 350 MW cables instead of 500 MW and a third 500 MW in 2032, alleviating the congestion phenomenon while securing a reliable power supply to the island.

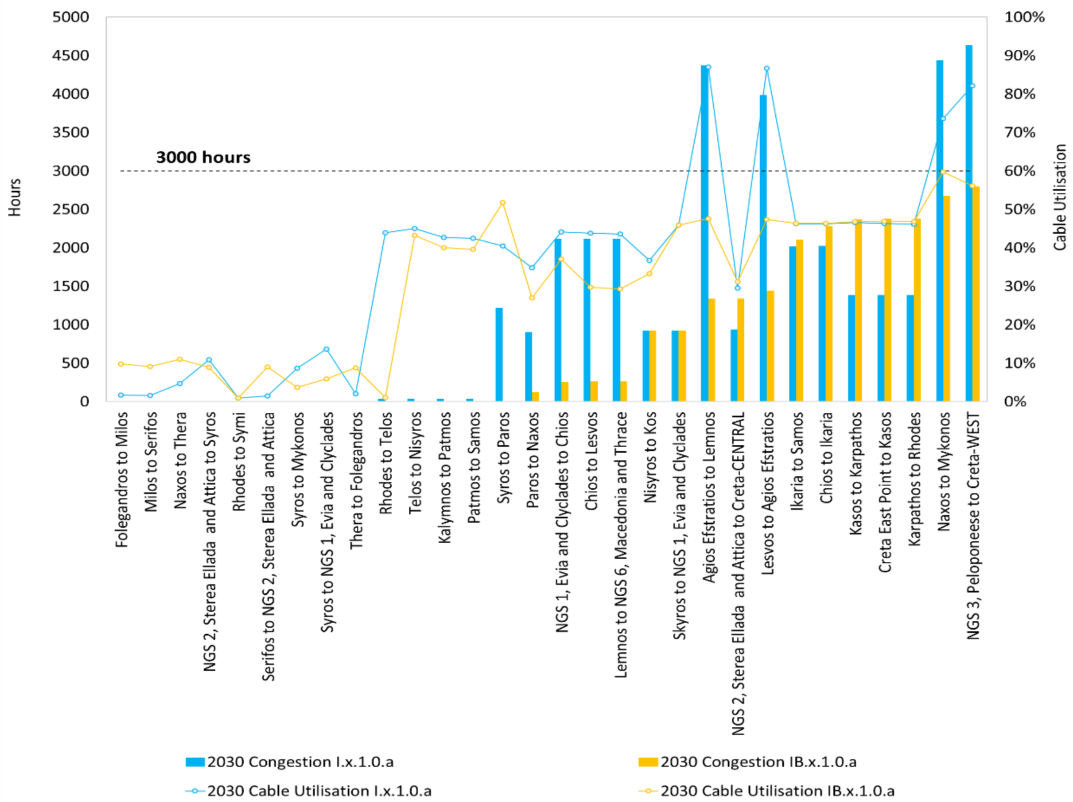


Figure 5.19: Congested hours and cable utilisation in 2030

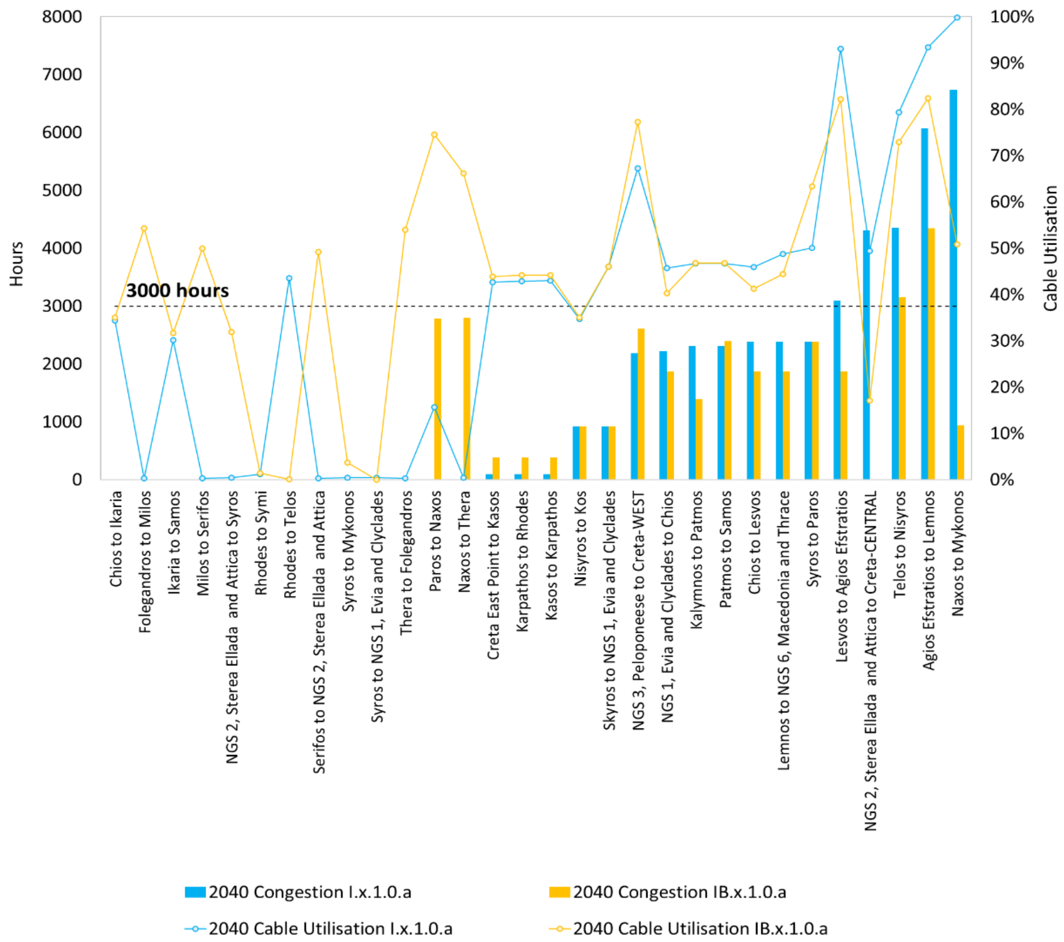


Figure 5.20: Congested hours and cable utilisation in 2040

5.2.5 BESS utilisation

The BESS effective management designates the economic viability of the installation contextualized within the respective island electrical system. Assuming generation restrictions are applied in the Autonomous context (AB.x.1.0.a), the use of batteries is swinging at minimum levels across 2030, equal to 5.5% on average. These results demonstrate the insufficient available generation from renewables to be stored and consequently redirected to the system. In the Northern Aegean Sea, Skyros, Dodecanese and Crete islands, the capacity factors range between 0 and 7%, according to Figure 5.21. An exception is the Cycladic region, where there is satisfactory usage of BESS; however, their systems do not avoid considerable power shortages, as discussed earlier. On the other hand, the effective use of BESS on small islands such as Agios Efstratios and Telos eliminates shortages. Assuming a scenario where thermal generation is not constrained (AB.y.1.0) while adding in the mix renewables, the deployment of BESS is expected to be 45% lower compared to AB.x.1.0.a. However, the storage capacity factor increases to 10% on average with the notable example of Rhodes, which reaches 27-29% while favouring the smooth power flow exchange in the region and minimizing unserved energy. Finally, considering the Interconnected case (IB.x.1.0.a), BESS instantly support the system to cover peaks while absorbing power during the nights with 80% less capacity than AB.x.1.0.a. Capacity factors record low levels of 4% on average with the exception of Crete and Paros. The Kos, Chios, Naxos, Milos, and Syros islands will not be operating a storage system while relying on the flexibility provided via the interconnection from other islands.

By 2040, the need for BESS will grow in parallel with RES deployment. This is reflected in increased usage factors across most islands while the Interconnection scenario records an average of 17%, the AB.x.1.0.a 9% and the AB.y.1.0.a 11.5% (Figure 5.22). Such results showcase the importance of BESS even under an interconnected network. Particularly, medium-sized islands such as Kalymnos, Syros, and smaller islands such as Serifos, Agios Efstratios and Symi frequently use batteries to eliminate imbalances in the AB.x.1.0.a context. The Cycladic and Rhodes islands succeed under AB.y.1.0 in eliminating power shortages while securing their electricity system against critical peaks using BESS with efficiency factors ranging between 8% and 37%. Such a scenario, however, implies higher levels of oil-fired generation. The island of Skyros records low levels across all scenarios demonstrating the minimum effect of a BESS for the island. Finally, a hybrid-interconnection scenario (IB.x.1.0.a) highlights the requirement to continue operating a storage system in the Cycladic islands, with Mykonos reaching a capacity factor of 56%. Such a scenario demonstrates the benefits of expanding the transmission network as it requires smaller capacity storage to stabilize the grid in the area and avoids grid congestion. According to the modelling outputs, batteries on Symi, Patmos and Crete can provide long-term discharge durations of 10 hours to the Dodecanese system, presenting higher capacity factors when interconnected. At the same time, Rhode’s BESS performance is relatively limited due to the maximum dispatch duration of 6 hours, showcasing the significance of the versatility of ESS characteristics for the system. By 2040, Kos, Chios, Milos, Naxos and Syros will continue to operate without BESS.

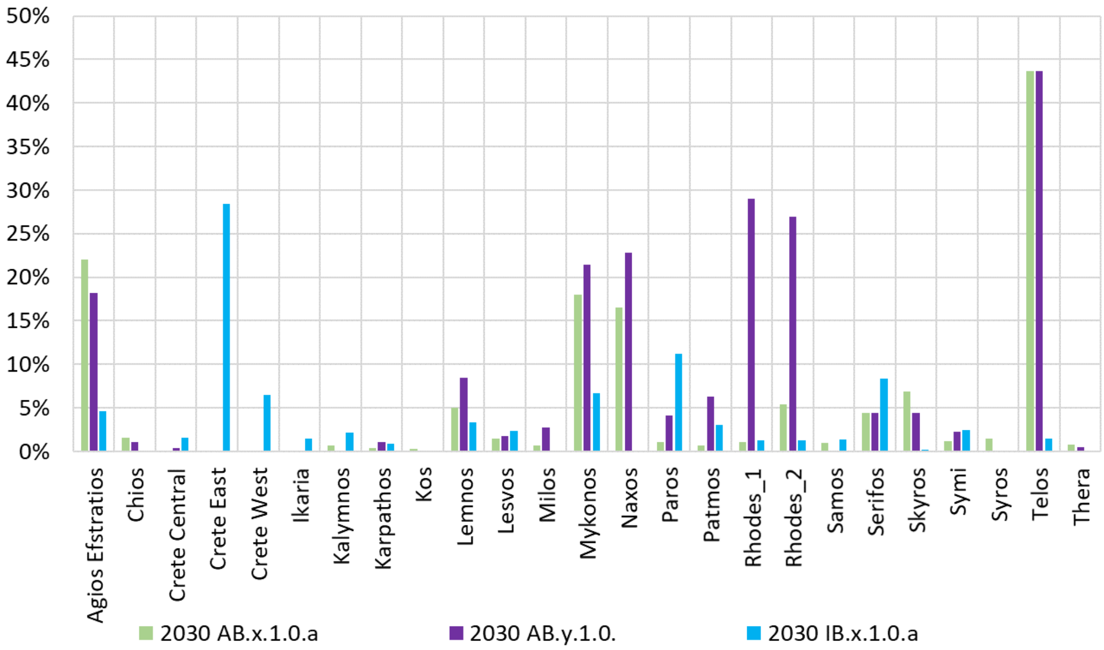


Figure 5.21: Capacity factor for BESS utilisation in 2030

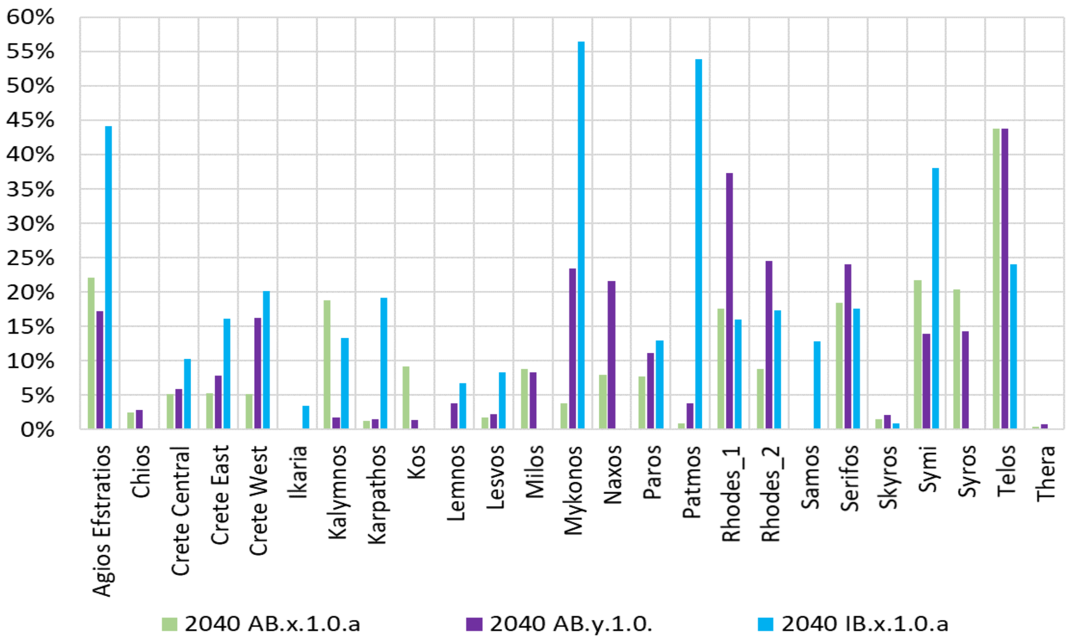


Figure 5.22: Capacity factor for BESS utilisation in 2040

5.2.6 EVs impact

5.2.6.1 *Load profiles*

According to the assumptions considering drivers' habits, the selected days depicted in the following figures represent weekdays: Monday or Tuesday when the first biweekly charging occurs and Thursday or Friday for the second. The scenario results prove that EVs impact on islands' power systems is non-negligible and could eventually amplify the 'duck effect' caused mainly between early morning and afternoon hours. As per the following graphs, synergies between EVs and utility BESS (AB.y.1.0.a) in a moderate electric mobility growth scenario (S1) generally achieve a smoother daily load profile. It becomes evident that considering the smooth load profile criterion, there is no apparent optimal charging pattern, while suitability depends on the seasonality. Seasonality is configured by two dimensions: demand load and RES generation supply. This is happening as battery hybrid systems prevail in size in this autonomous context.

During an average week with moderate demand in 2030, the unscheduled daily scenario fills the night-time valley due to utility-scale battery charging, which in the evening is used to cover EVs demand (Figure 5.23). Under a more ambitious (S2) scenario in terms of EVs growth, the trends are intensified, resulting in sizable spikes mainly deriving from the biweekly morning and unscheduled charging scenarios and public charging. Consequently, the benefits of V2G (restricted or unrestricted) and those of daily charging become most prevalent under the S2 EV scenario. Thanks to the V2G spreading charging loads over the day, it contributes to flattening the curve. Differences between the V2G and V2G-restricted options concern the limited available periods, cars can charge and discharge. Therefore, beyond the noticeable impact on the grid, V2G-restricted also generates higher energy quantities during the early morning.

V2G generation is dispatched depending on demand requirements, committed thermal units, and the available power produced by must-run renewable energy, following the dispatch merit order. During the maximum week (Figure 5.24), a higher number of gas turbines is committed, resulting in lower levels of V2G generation than anticipated. Daily off-peak scheduled charging patterns, where EV owners choose to plug in their vehicles at home, achieve to fill in night-time valleys. On the other hand, unscheduled or public charging takes place with fast-chargers over a short period in bulk, recording demand spikes that stress the system as there is a lack of sufficient flexible units to cover 134 MW of additional demand.

Another striking example at the minimum week of 2030 (Figure 5.25) is the public charging scenario's performance. During times of EV charging, utility-scale batteries charging is postponed for the night-time. Hence, certain scenarios succeed in reducing the charging loads of utility batteries while absorbing power from the system without injecting it back as grid-connected batteries. The comparison between S1 and S2 designates the additional risk for the system across all weeks.

Uncertainty in the power system increases by 2040, as depicted in Figure 5.26 - Figure 5.28, as more renewables and EVs, are deployed on the islands. The charging options stressing the system the most are morning and public charging scenarios and, in general, the biweekly scenarios that cause overloading while putting transformers at risk, leading to sharp demand load spikes. Under the Autonomous Batteries scenario, the V2G-restricted pattern creates a smoother profile as it distributes evenly load while contributing with power injections (Figures 5.26). Also, V2G generation increases as onshore wind and solar deployment do not meet the demand requirements, while no interchange between off-shore wind farms and the islands is envisaged. Over the maximum week (Figure 5.27), most evidently under the S2 case, the V2G-restricted scenario shows that a considerable group of EV users will be ‘forced’ to charge one to two hours before departure while creating spikes between 6:00 and 8:00 in the morning. Furthermore, the Tourism scenario demonstrates critical loads exceeding 4,000 MWh during the evening.

Under the interconnection case – I.x.1.0.a (Figure 5.29 – Figure 5.34), similar trends are observed. In the absence of storage to regulate demand and supply discrepancies, EV charging impacts the demand curve directly, especially under the biweekly charging profiles. The charging load is partially covered by increasing imports from the mainland and local renewable generation. V2G scenarios and scheduled charging options demonstrate a clear path by smoothening the daily demand profiles. This showcases that indirect, cost-driven charging patterns, even under restrictions, are the most efficient in minimising demand spikes. V2G injection to the grid is considerably higher in this context (up to 1900 MW versus 130 MW in the Autonomous case), especially during peak evening-time. This shows a larger margin for bidirectional generation to cover demand loads since flexible local thermal generation is shut down. Also, bidirectional charging contributes to ancillary services provision under such a scenario.

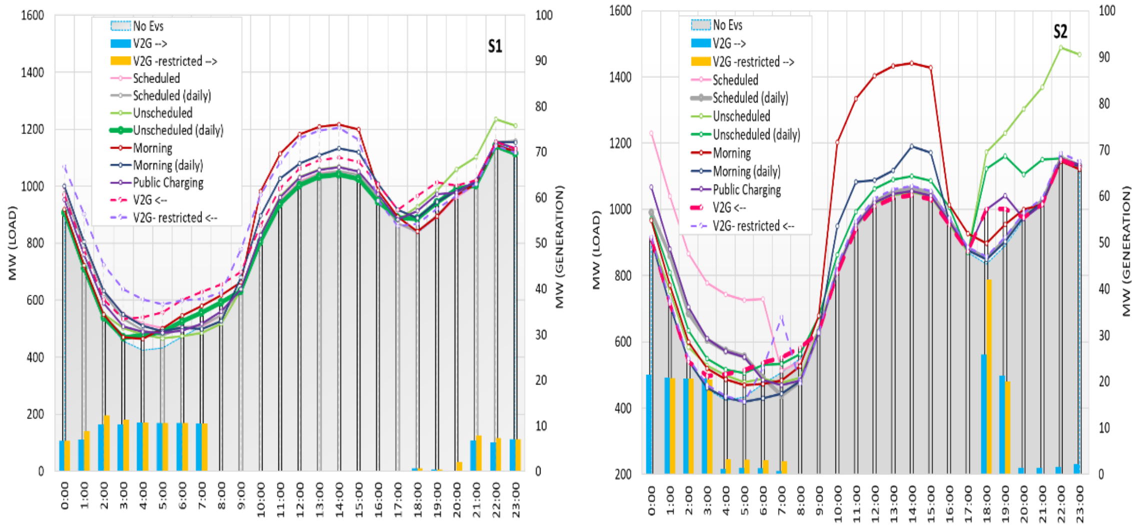


Figure 5.23: Representative daily EV load profiles -2030 Average week (AB.y.1.0)

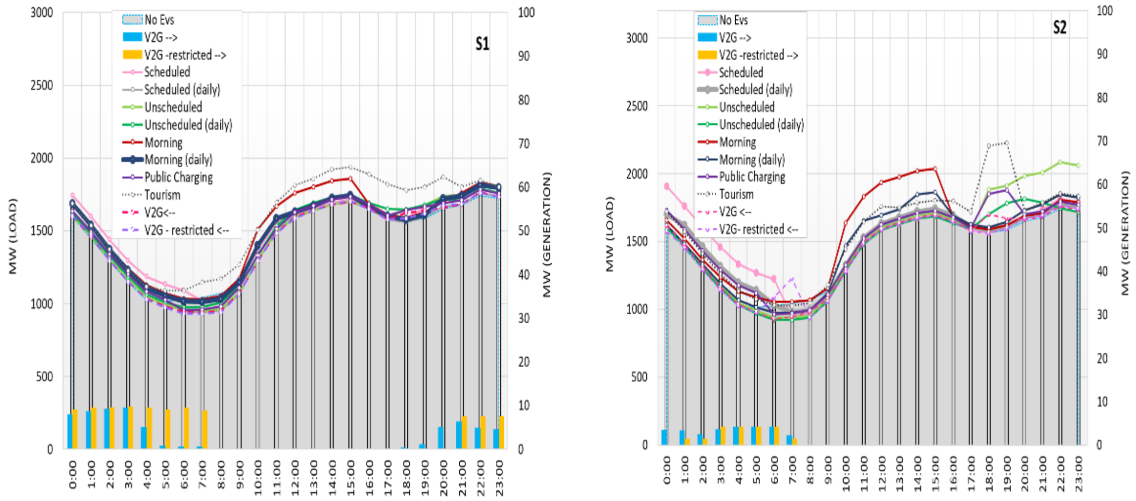


Figure 5.24: Representative daily EV load profiles – 2030 Maximum week (AB.y.1.0)

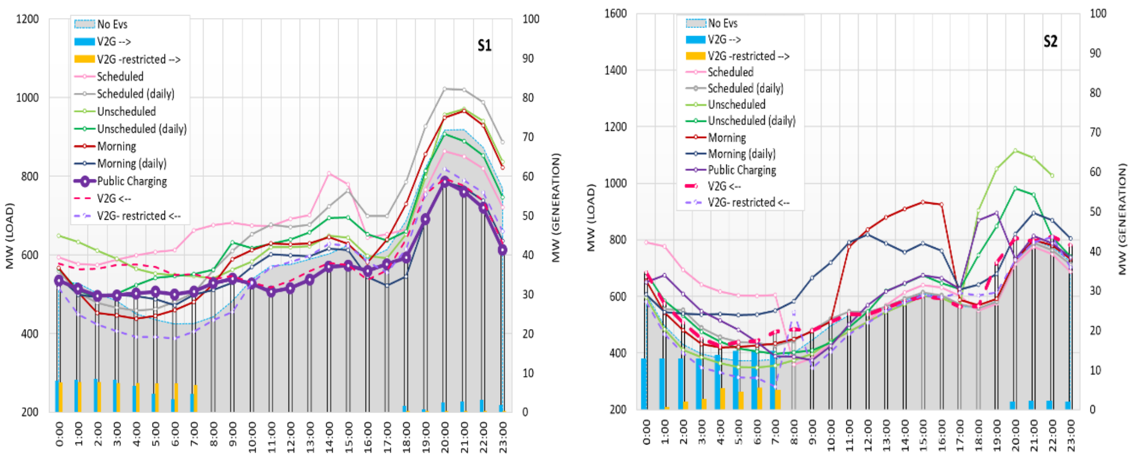


Figure 5.25: Representative daily EV load profiles - Minimum week 2030 (AB.y.1.0)

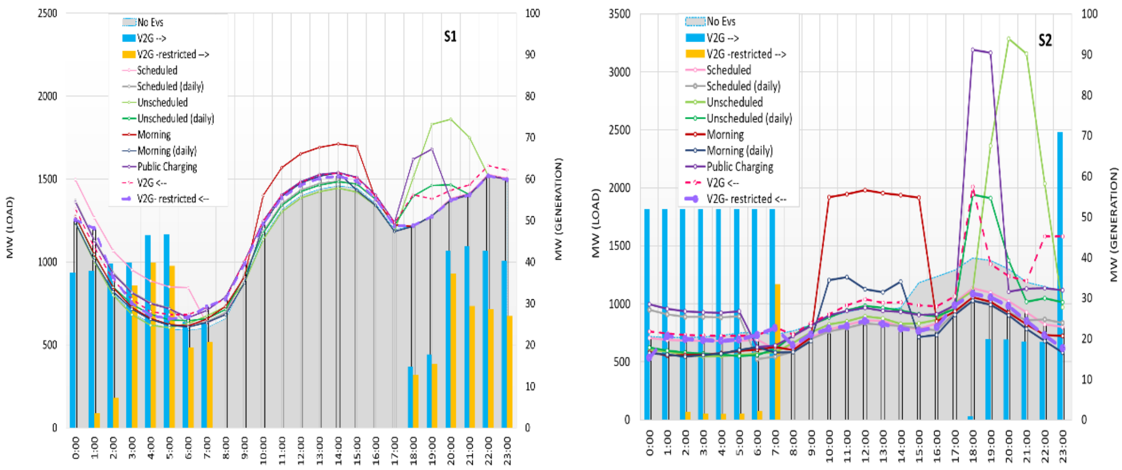


Figure 5.26: Representative daily EV load profiles - Average week 2040 (AB.y.1.0)

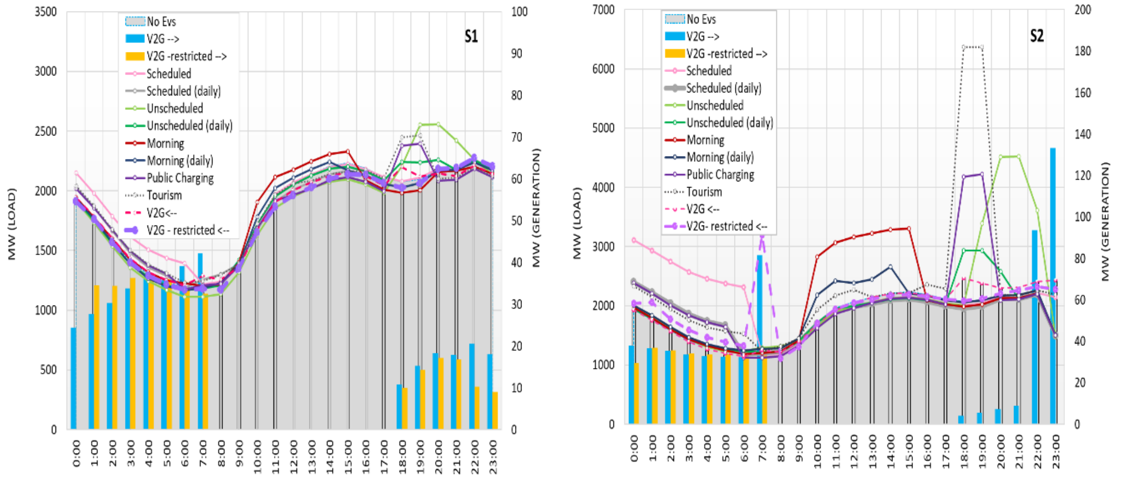


Figure 5.27: Representative daily EV load profiles - Maximum week 2040 (AB.y.1.0)

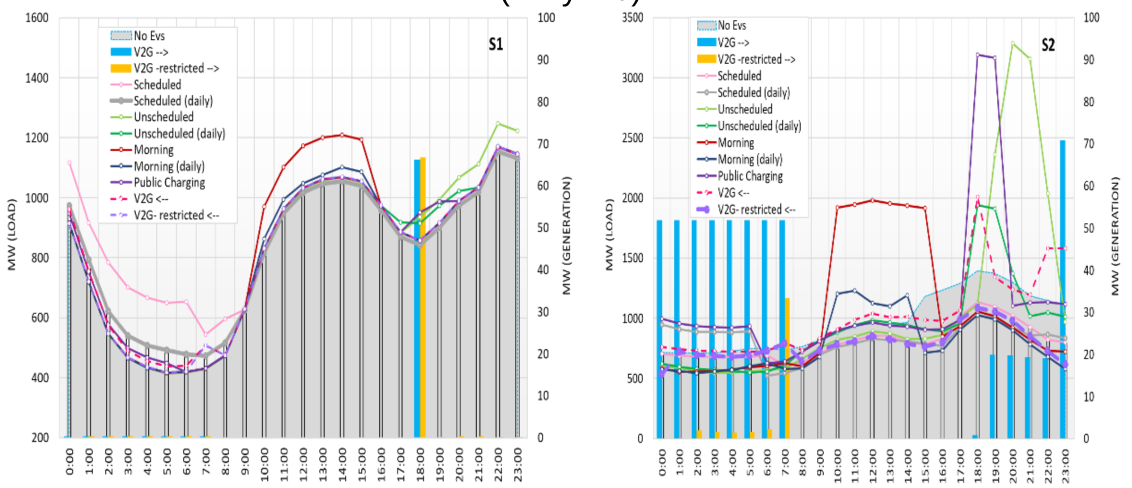


Figure 5.28: Representative daily EV load profiles - Minimum Week 2040 (AB.y.1.0)

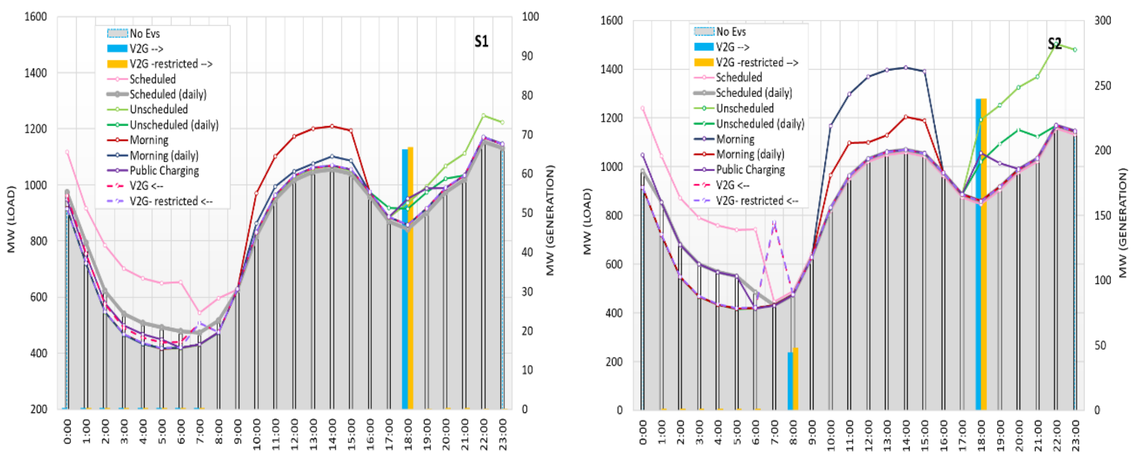


Figure 5.29: Representative daily EV load profiles - Average week 2030 (I.x.1.0.a)

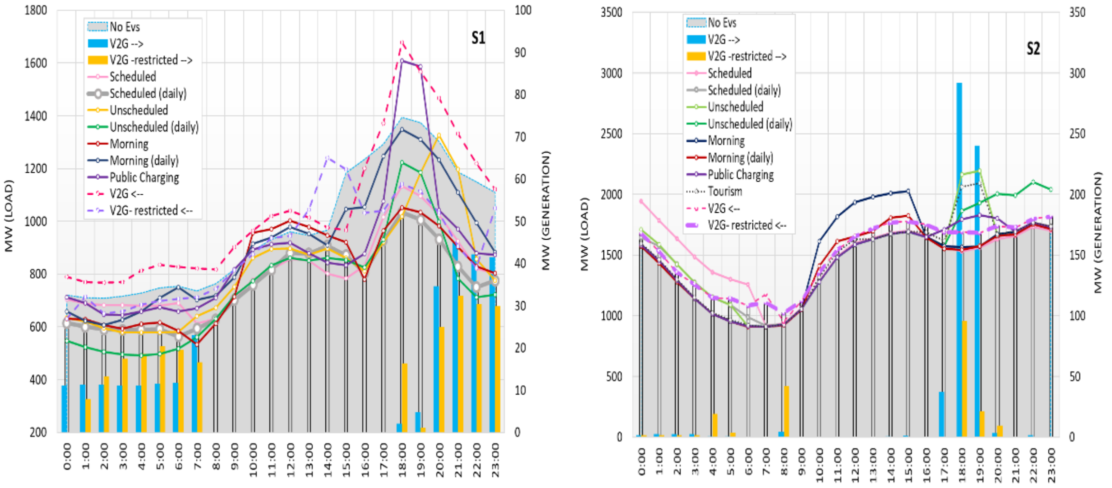


Figure 5.30: Representative daily EV load profiles – Maximum week 2030 (I.x.1.0.a)

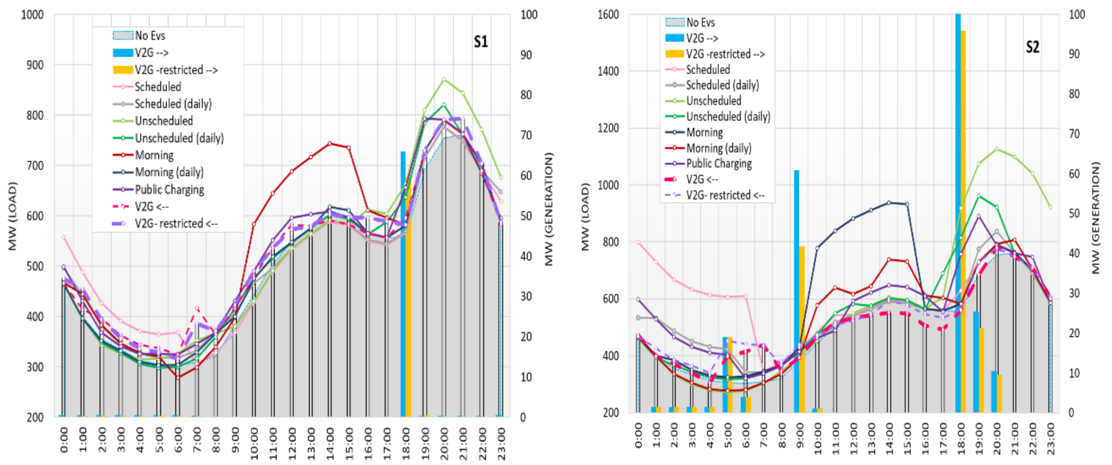


Figure 5.31: Representative daily EV load profiles – Minimum week 2030 (I.x.1.0.a)

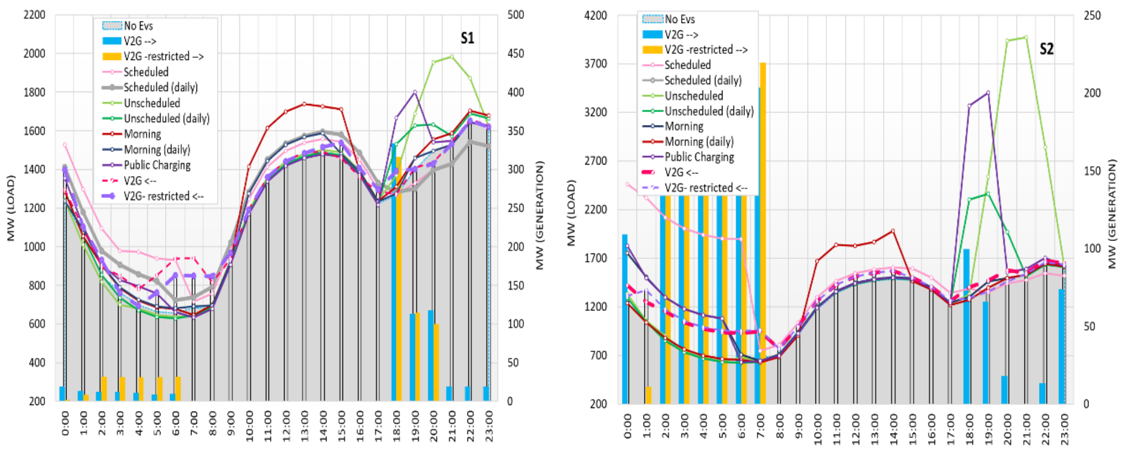


Figure 5.32: Representative daily EV load profiles – Average week 2040 (I.x.1.0.a)

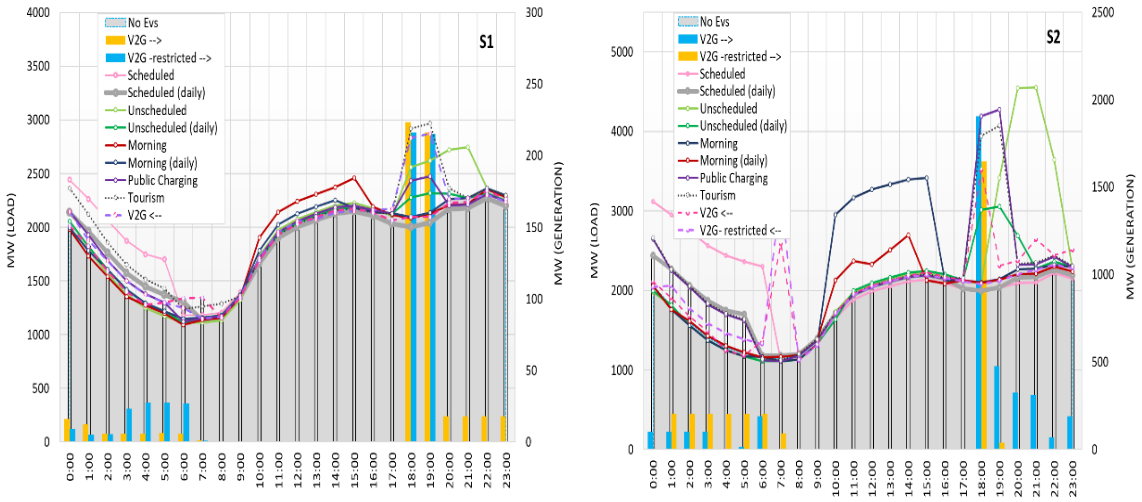


Figure 5.33: Representative daily EV load profiles – Maximum week 2040 (I.x.1.0.a)

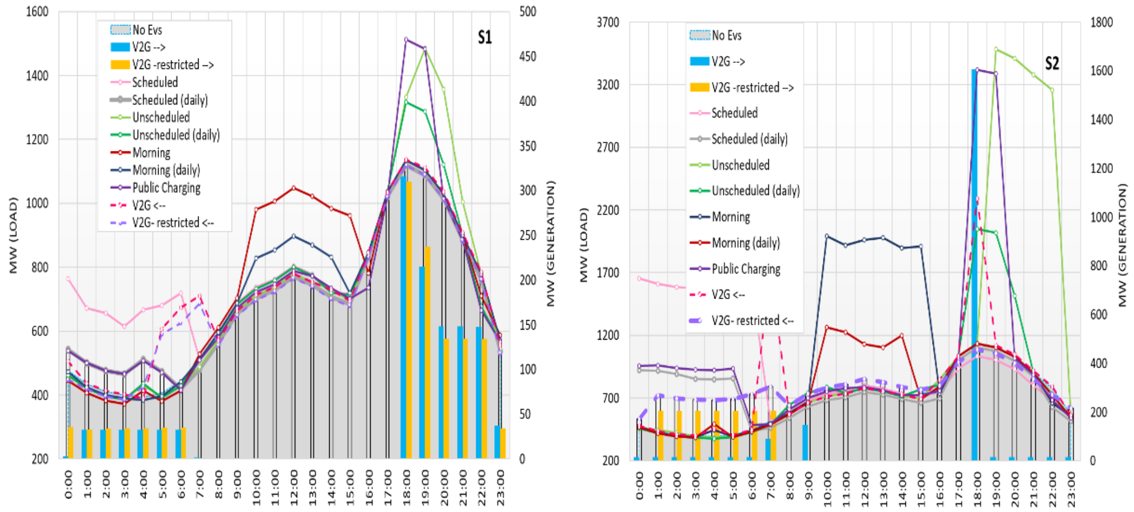


Figure 5.34: Representative daily EV load profiles – Minimum week 2040 (I.x.1.0.a)

5.2.6.2 *System balancing and reliability*

Despite the undeniable benefits of electrifying mobility under a sustainable electricity mix, EVs add uncertainty to the grid, subject to charging and discharging timing, quantity and location. Thus, the importance of an integrated energy plan considering the future requirements and opportunities emerging from the use of electric vehicles is undeniable. According to

Figure *5.35*, the AB.y.1.0 scenario triggers continuous power shortages under the unscheduled daily or biweekly charging profiles as well as under the public and morning charging options. During the 2030 average week, the unscheduled charging profile will not satisfy 0.4% of the total demand required under S1, while this figure is amplified to 0.65% under the S2 scenario. During the 2030 maximum week, peak-charging scenarios range at low levels between 0.1 and 0.2% under both S1 and S2 scenarios. The V2G constrained scenario will also experience power cuts equal to 0.5% of the total demand due to increased loads between 6 and 7 a.m. Over the minimum week, no major incidents are recorded.

By 2040, power shortages will increase both in terms of frequency and duration. Under S1, during the average week, the impact is limited. Nevertheless, under an ambitious (S2) scenario where EVs take over 82% of the total fleet adding up to 2400 MW in the system, unserved energy will skyrocket to almost 6% in peak charging scenarios, e.g., public charging and unscheduled scenarios. Furthermore, over the maximum week, the Tourism scenario is going as high as 2% under S1 and 3.6% under S2, proving that if a sustainable tourism scenario is to be followed, relevant investments in power generation and transmission capacity should take place. Finally, during the minimum week, where no incidents occur in a moderate scenario, charging patterns that strain the system will not meet 2 - 3% of the demand loads.

The islands most volatile to power shortages under the autonomous state are mainly located in the Dodecanese complex, including Kos-Kalymnos, Rhodes, Kasos-Karpathos and Symi, exposing the fragility of these remote electrical systems. A rapid scale-up of transport electrification by 2040 will also create significant power shortages of up to 4.5% on islands such as Crete, Paros and Syros as highly touristic islands.

In the absence of energy storage, an interconnected islands network will experience higher unserved energy levels. The islands most affected are Crete, Thera and the Dodecanese region. During the average week of 2030, a reduction in power shortage across all scenarios is recorded, assuming a moderate growth of EVs. However, under the ambitious S2 scenario, most charging profiles evidence power shortages as high as 4% of the total demand in the same week. Exceptions remain the daily scheduled options and the V2G scenarios that enhance local flexibility, allowing them to inject energy into the system during late evening hours, where power shortages are usually recorded. Over the maximum week in S1, most charging profiles range at the same levels as a non-EV profile near 6%. This is not the case in the S2 scenario, where the morning scenario cannot suffice for 9% of the demand, as all the available resources are exhausted.

The Tourism scenario could jeopardise the system's security under the interconnected case where imported EVs belonging to tourists would cause significant amounts of unserved energy ranging between 5% (S1) and 7% (S2) in 2030 while exceeding 9% in 2040. Those scenarios that reduce unserved demand are mainly the V2G scenarios that bring down power shortages by 30 to 100% compared to a non-EV case. As a general outcome, seasonality shapes the suitability of the various charging profiles, with peak charging profiles and biweekly charging, leading to higher unserved demand levels than in a non-EV scenario. On the other hand, scheduled daily and V2G scenarios avoid significant power shortage events across most of the year.

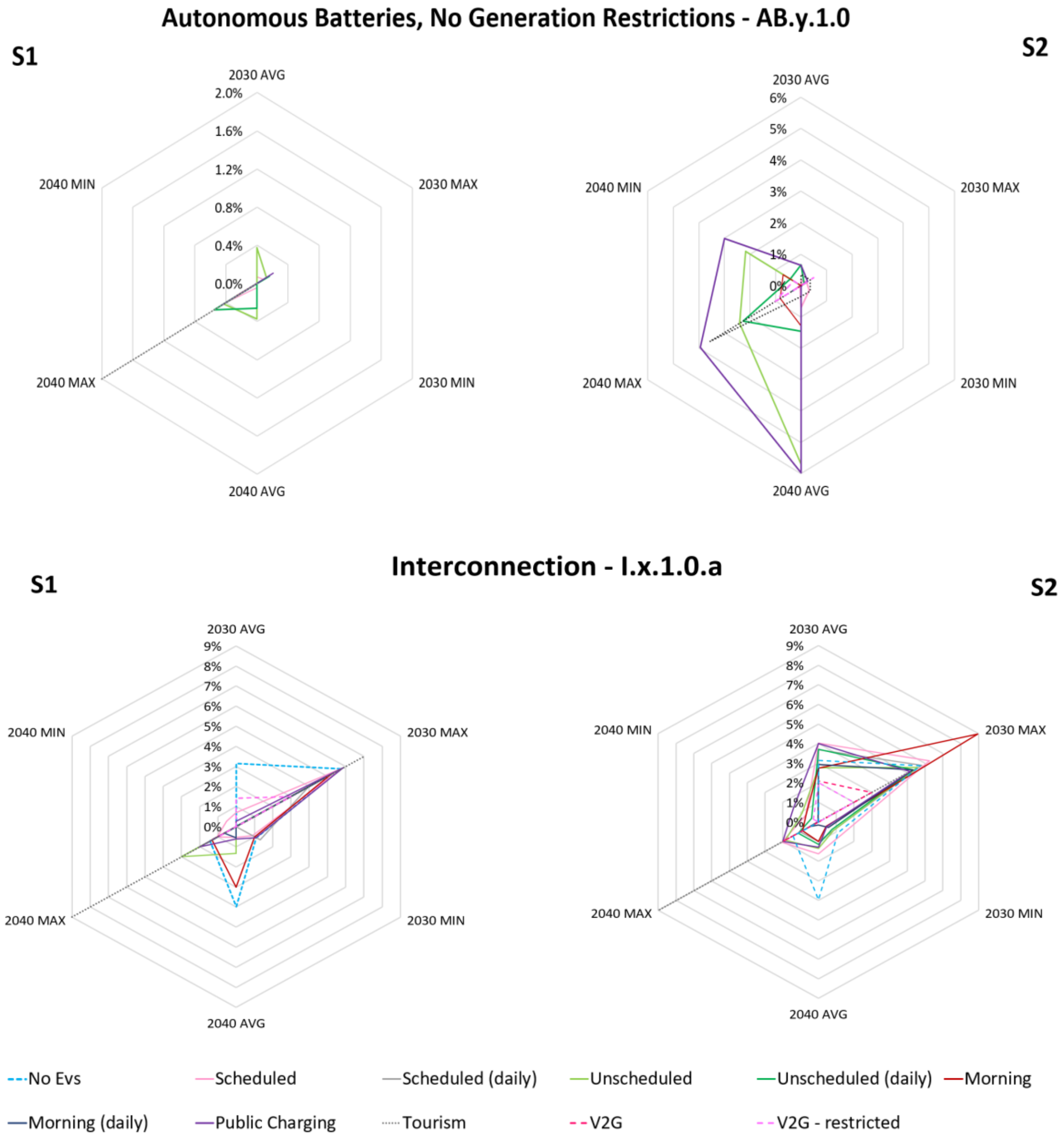


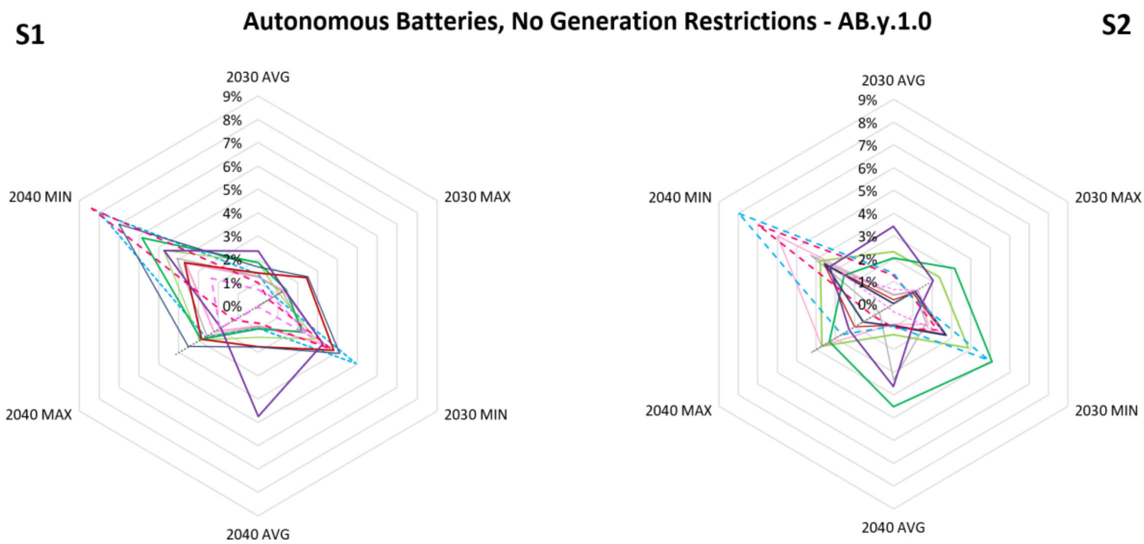
Figure 5.35: EV charging scenarios unserved energy per representative week

Furthermore, options favouring scheduled daily charging minimise curtailments while contributing to valley feeling and peak shaving in the AB.y.1.0 case. Over the 2030 average week, the scheduled and daily morning scenarios record values similar to the baseline non-EV profile. The unscheduled and biweekly morning profiles increase up to 2%, and the public charging profile up to 2.5% (Figure 5.36). During the summer, no considerable changes are observed, while better performance across all scenarios is observed in the minimum week. Considering the S2 case, these incidents are amplified. Notably, 3.5% of energy spillage is recorded assuming public charging under a moderate load profile. Over the summer months, the unscheduled scenario records the highest values, equal to 3.2%. This is anticipated as loads occur during peaks, while wind energy generated during the night when batteries are fully charged cannot be absorbed. Such phenomena result in additional charging/discharging full cycles that deteriorate battery lifetime. In parallel, they restrict utility batteries installed on islands to discharge up to the minimum SoC, usually between 18:00-21:00. During the traditionally minimum weeks, which record the highest energy spillage, all EV scenarios, but the unscheduled, succeed in reducing curtailed energy below 5%.

In 2040, the unscheduled scenario continues to be the least efficient scenario, with 4.5% of curtailed energy recorded during spring, considerably higher than a non-EV scenario curtailing approximately 0.9% of the total RES generation. In the summer, the Tourism scenario records values equal to 4.2%. During weeks with minimum loads, all EV scenarios succeed to reduce energy spillage, with the most successful being the V2G-restricted, which responds to the market signals and minimises such incidents at approximately 2% across both S1 and S2.

In the Interconnection Scenario, curtailed energy is relatively lower than in the Autonomous Batteries scenario as it allows power flows exchange among the islands and the mainland. While there is a limited impact on the grid during the average weeks, concerning maximum loads, curtailed energy increases across all the scenarios, with the highest figures of 4%, recorded in the morning daily and Tourism scenario. This is attributed to EV charging during morning hours failing to smoothen the demand curve while shifting hydro storage generation from evening hours to 14:00 to 16:00 to serve the requested loads. On the contrary, over the minimum week, curtailments are reduced under the S1 scenario since the additional EV load balances demand and supply during early morning hours. Assuming a more ambitious EV scenario, the impact is still reduced over the average and maximum weeks, but curtailments go up to 9% for public charging in the minimum week. Due to constraints, curtailed energy occurs mainly on islands operating hydro pump stations, forcing them to inject energy during valleys while shifting pumping schedules to accommodate EVs charging requirements.

In 2040, there is a significant increase in curtailed power. Through the maximum week under the peak charging scenarios, curtailments range from 1% in the non-EV case to 5.2%, underlining the negative impact of uncontrolled charging loads on the grid. The levels of energy spillage skyrocket to 6.8% for S1 and 8.7% for S2 scenarios through winter. Overall, assuming interconnections occur, the V2G and scheduled daily patterns eliminate curtailments in the S1 case. Only the V2G restricted scenario keeps the curtailed values below 2% across the year in a more ambitious scenario. The Tourism scenario reaches as high as 8% during the maximum week, underlining the severe impact of such a scenario on the system.



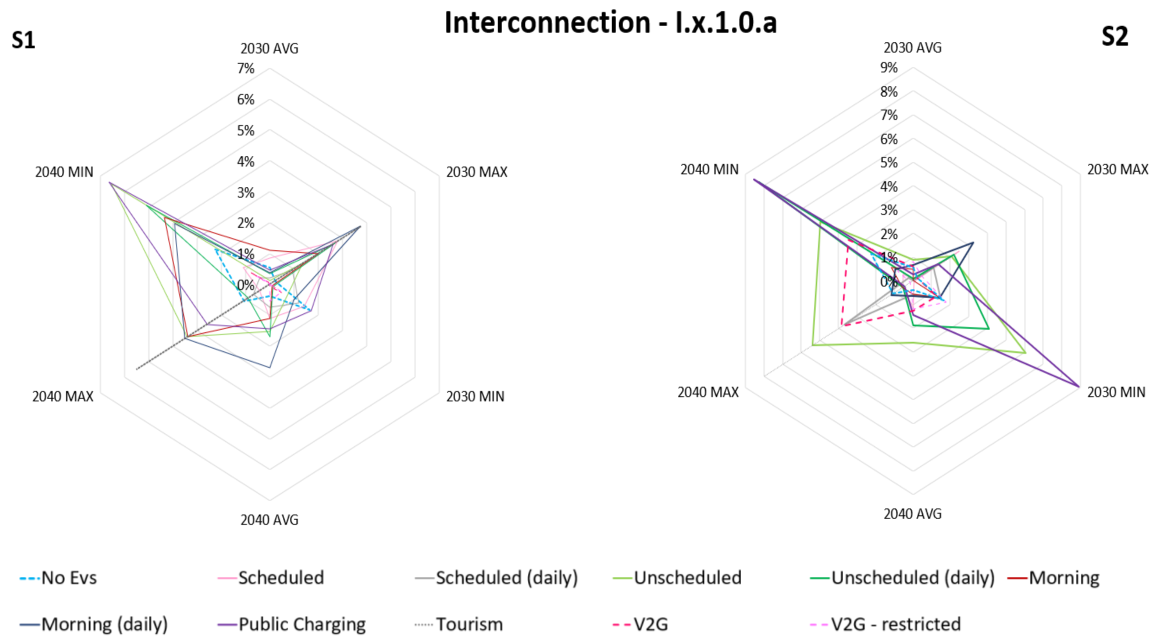


Figure 5.36: EV charging scenarios curtailed energy per representative week

5.2.6.3 *RES integration*

Electric vehicles will play a role in supporting renewables development if optimally placed during the day, considering seasonality trends in demand and RES generation. In the Autonomous case (AB.y.1.0), as depicted in Figure 5.37, renewables generation is relatively low under a baseline non-EV scenario as new RES are limited by the constraints discussed before. Therefore, there is an inevitable decrease in RES share when EVs are introduced in 2030, reflecting thermal generation dispatch as the only alternative. During the maximum week, the demand load increases unproportionally; consequently, the only option to satisfy EVs' demand continues to be local thermal capacity dispatch and complementary energy stored in batteries. In general, unscheduled and public charging options forcing users to charge over daily peaks usually require a higher thermal capacity to meet demand. This is reflected in RES shares decreasing down to 20-22%. It becomes evident that in 2030 only during the minimum load week, EVs charging will attain a relative RES share increase up to 3.2%. Presuming that an ambitious EVs scenario (S2) is in place, the only charging patterns to increase renewables' share are the daily scheduled charging and the V2G scenarios. This is achieved by reducing curtailments and increasing the generation of dispatchable RES. On the other hand, morning charging scenarios due to reduced winter irradiation do not have a competitive advantage. Despite the two scenarios S1 and S2, recording similar trends, in the latter, the V2G scenarios succeed in increasing RES shares over the average and minimum weeks by intensifying the charging and discharging cycles of battery storage while forcing higher capacity factors in hydro pump stations.

In 2040, during the average week, morning charging scenarios, including the V2G, increase the share of RES in the generation mix between 4 and 6% as there is approximately a twofold increase in the RES installed with ample margins for operational optimisation. In particular, the results show curtailment elimination of solar and hydropower dispatch increase during morning hours. Over the summer represented in the maximum week, EV demand concerning peak charging scenarios is met principally by thermal generation at a range between 60% and 80% complemented by battery discharging. Consequently, RES share is reduced across all scenarios, escalating to 31% under S2 pubic charging. The V2G – restricted scenario that allows for clean energy discharging while minimizing oil-fired dispatch presents a lower reduction in RES share. Finally, over the minimum week in wintertime (S1) most scenarios except for morning and public charging seem to be able to sustain a fair share of renewables while meeting charging demand needs. On the contrary, in a more ambitious S2 scenario, none of the charging options sustain this record while the charging requirements grow disproportionally.

In the Interconnection Scenario, in 2030, considering average generation loads, the V2G scenario prevails across both a moderate and an aggressive EV deployment scenario (Figure 5.38). Most of the additional demand is met by imports over the maximum load week. The scheduled and V2G scenarios increase RES participation up to 12% during the minimum week. Under a more extreme S2 scenario, only the V2G option meets charging demand while increasing RES share up to 6% during winter. The bidirectional use of EVs allows for charging principally during night-time when the highest daily valley is recorded and injecting energy back to the grid over the same period or during the evening peak. The rest of the scenarios scored low in greening the energy mix further, unlike the autonomous case, where utility storage batteries allowed for higher flexibility.

Even though general trends are observed, certain specificities are also evidenced, related to the stochasticity of wind and solar in modelling simulation. For example, under the S2 Scenario, Crete island records lower RES reduction during evening peaks than in the S1 case, demonstrating marginally higher wind speeds over that particular simulated week.

Assuming all interconnections are realized by 2040, during the average week, V2G scenarios succeed in optimising local capacity mainly under S1 with RES increase up to 7%, with daily morning charging sustaining its satisfactory performance across both S1 and S2 scenarios. Over the maximum weeks, as in the autonomous case, local capacity is reaching its limits, and the additional demand is met by imports from the Greek mainland for both scenarios, with the exception of bidirectional charging plans. Finally, in the minimum week where most of the demand is met by local generation, certain charging scenarios such as the evening and morning scheduled can cater to electromobility needs without signaling additional imports. On the other hand, under the public charging scenario, the mismatch between local available generation and demand will reduce the share of RES in the electricity mix by 20% in S1 and 30% in S2.

On the whole, the results prove that electromobility could increase the dispatch of renewables considering the existing capacity and mobilise the development of more stochastic and dispatchable renewable energy projects to cover charging demand across the day, as indicated in Table 5.5. Furthermore, as renewables generation is highly seasonal, there is not always one optimum solution across the year. Therefore, beyond the undeniable better performance of the V2G scenarios, the outcomes showcase that daily morning charging could support the injection of more solar power when the demand is relatively low. However, the irradiation is relatively higher, e.g., between April and May and September to October. The scheduled daily scenarios also fit well during wintertime when the demand reaches its annual low. As a general rule, unscheduled and biweekly morning charging, including public options, increase the use of oil-fired units due to the incapacity of the available RES units to supply power. Another critical dimension is that higher RES integration will not always lead to lower emissions and vice versa. Thus, we need to quantify the impact of energy storage, imports, and additional thermal generation dispatched on each island's electrical system to meet the EV charging demand.

Table 5.5: Additional RES capacity in the Greek islands' region due to EVs deployment

Scenario		**Year**	
		2030	**2040**
Main Scenario	**EVs Growth**	**MW**	
AB.y.1.0	**S1**	120	480
	S2	260	720
I.x.1.0.a	**S1**	65	360
	S2	150	600

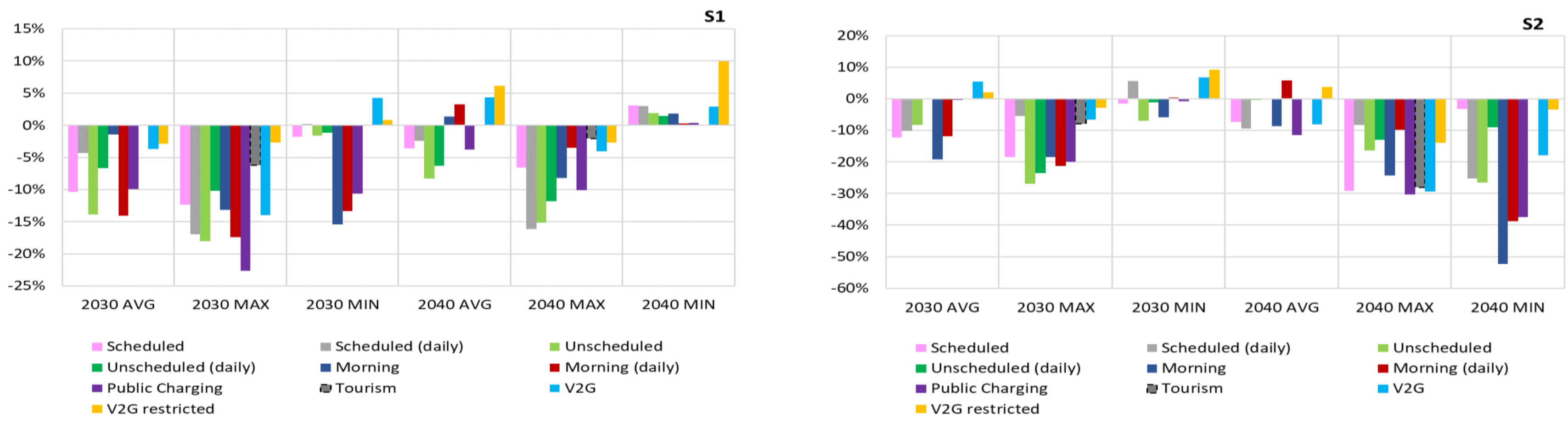


Figure 5.37:RES integration variations per representative week – Autonomous Batteries (AB.y.1.0) scenario

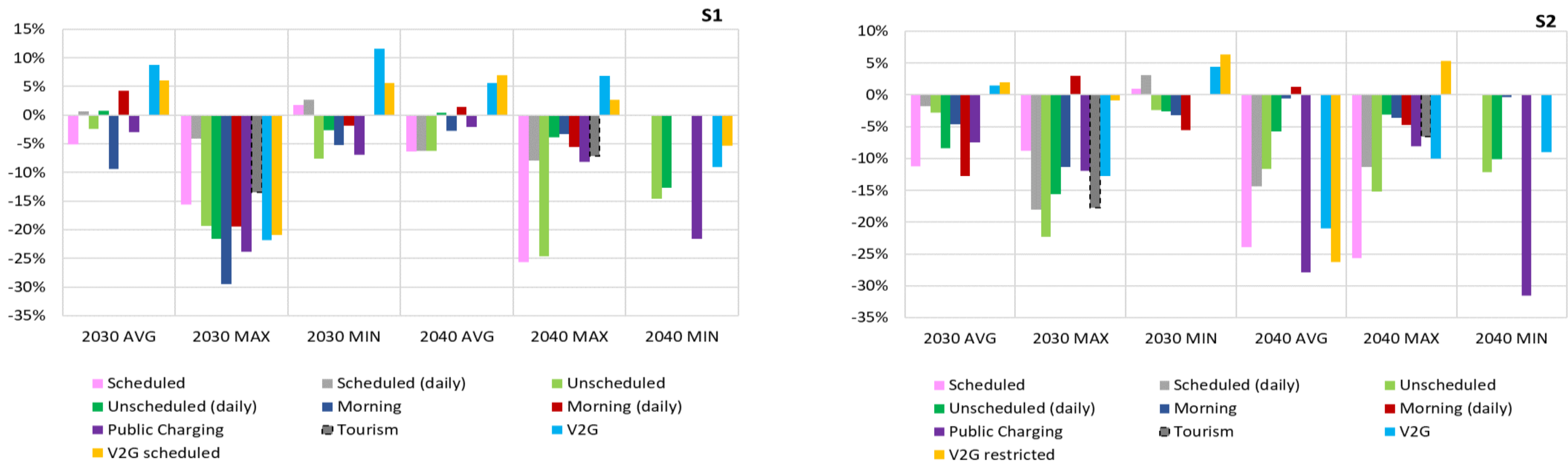


Figure 5.38:RES integration variations per representative week – Interconnection (I.x.1.0.a) scenario

5.3 Economic affordability

5.3.1 Total electricity costs

Interconnections reduce cumulative costs over the next 20 years in the Greek electricity system by 11€ billion compared to the continuation of autonomous operation (A.y.1.0.a), which requires 180€ billion between 2020 and 2040, according to Figure 5.39. The cost savings are attributed to replacing oil-fired generators with wind and solar-powered units entailing lower levelised costs despite the transmission costs of approximately 5.5€ billion. The involvement of 10.5 GWh of storage capacity effectively balances demand load profiles on islands under scenario IB.x.1.0.a increases expenses by 2€ billion compared to the base interconnection scenario (I.x.1.0.a), recording the lowest costs at 170 billion; although, the actual price paid by consumers is reduced as discussed later. On the whole, the importance of enhancing the regional submarine network operations outweighs this investment cost. The Autonomous-Batteries scenario (AB.x.1.0.a) costs 12.4€ billion more than the Autonomous scenario (A.y.1.0.a). AB.x.1.0.a demonstrates relatively low capacity factors throughout the rest of the year. The results show that despite specific scenarios requiring high upfront investment costs on the islands, they manage to offset generation costs while reducing investments in the mainland, leading to overall reasonable costs for the Greek electricity system.

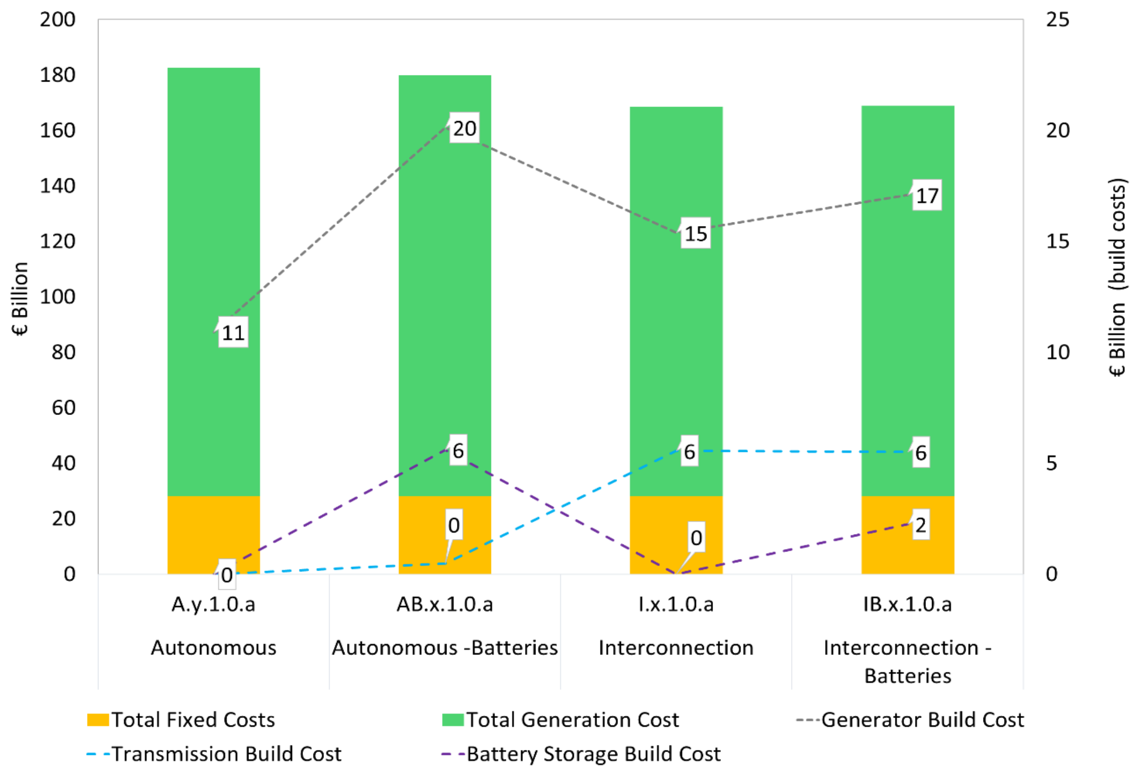


Figure 5.39: Total aggregated system costs over the projection horizon (2020-2040) – Principal scenarios

5.3.1.1 *Sensitivity Analysis*

The sensitivity analysis deploys different trajectories which the aforementioned Principal Scenarios could eventually take, illustrated in Figure 5.40. By imposing LS fuels for power generation horizontally (A.y.1.0.d), the total costs increase by 6€ billion in the Autonomous case. If BESS are deployed, costs will increase to 3.8€ billion in AB.x.1.0.a compared to AB.x.1.0.b, which assumes no use of low sulphur as local thermal generators are utilised minimised in this scenario. Adopting ambitious plans for energy efficiency on islands in parallel with high renovation rates in the High_Eff ISLA_EGI scenario could bring down costs to 3€ billion approximately, both for the Autonomous Batteries (AB.x.1.2.b) as well as for the Interconnection scenario (I.x.1.2.b). In case the current autonomy continues, the benefits of efficiency measures climb to 6€ billion (A.y.1.2.b). This is anticipated as local electricity production still relies on expensive oil-fired units.

On the contrary, the relatively low oil fuel prices forecasted under the 'Current Policies' IEA Scenario allow local thermal units to sustain their operation subject to the restricted generation cap, leading to lower cable capacity usage. Furthermore, the combination of moderate policies in terms of energy efficiency brings up costs to 5€ billion in the Interconnection Scenario (I.x.2.1.) compared to the baseline Interconnection case (I.x.1.0.a). The effect of such modelling input assumptions in the autonomous case (A.y.2.1.) would steeply cost up to 11.7€ billion over the 2020-2040 projection horizon due to the extensive use of oil. In the Autonomous Batteries case (AB.x.1.1.b), the additional costs from a low ambitious energy savings scenario would be 9.8 € billion. Overall, we notice that oil fuel and CO_2 emissions prices have a limited impact on the islands' region once it becomes interconnected compared to the Autonomous pathway since a large part of the conventional capacity retires. Implementing offshore wind projects of 934.15 MW capacity is estimated to bring down costs by 2.8 € billion. Offshore wind displaces thermal and specific onshore capacity with lower levelised costs but also lower capacity factors.

Directives 2010/75/EU and 2015/2193/EU encumber oil-fired generation under the Autonomous Pathway, resulting in capital-intensive investments in new thermal generators to fill the demand gap. This results in overinvestment in power generators under the Autonomous Battery set of scenarios to allow islands power systems to cover summer peaks. A balanced distribution between generation and transmission build costs is observed if subsea interconnections are implemented. Under the Autonomous pathways, local RES integration continues to be limited to 30% of the annual peak demand of the previous year due to its intermittency therefore costs concern mostly power generation costs. Finally, the cost-optimal IB.x.1.0.b invests moderately in clean, decentralised technologies while emphasising conventional, cost-efficient technologies such as natural gas generators in the mainland, transmitting power to the islands' region. Beyond the cost savings, this scenario has limited energy security and environmental sustainability benefits while maintaining the islands' region's reliance on imported conventional fuels.

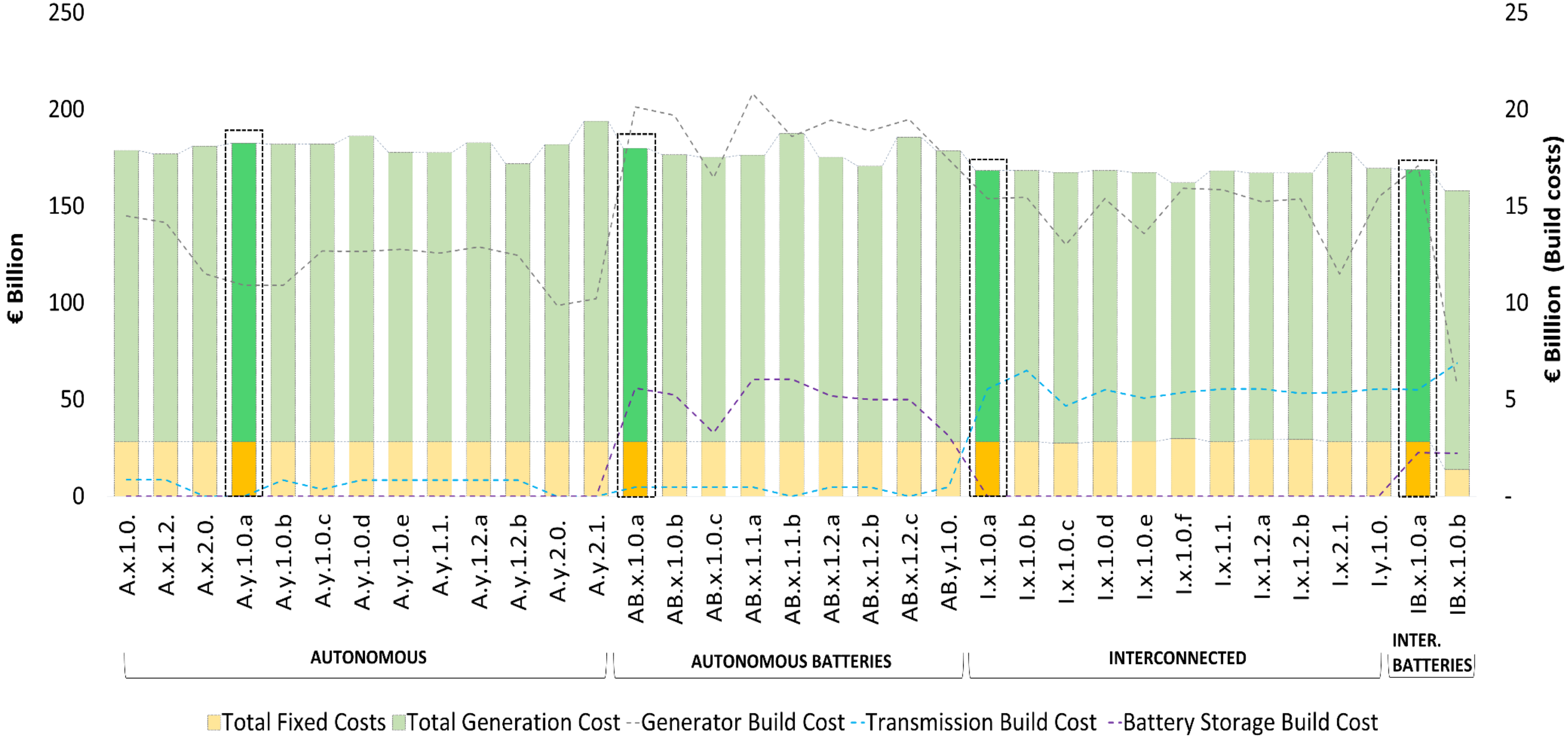


Figure 5.40: Total aggregated system costs over the projection horizon (2020-2040) – Sensitivity analysis

The annual total costs considering the islands' region are depicted in Figure 5.41. The results show that the most expensive scenario is the Autonomous-Batteries (AB.x.1.0.a), with a faster evolution following 2032 due to the increased needs in generation capacity. The need for a total phase-out of the existing thermal stations and the steep peaks recorded during the summer require large-scale ESS and gigantic wind farms to meet the demand. The second most costly option is the baseline scenario A.y.1.0.a, with minor fluctuations, investing mainly in new oil-fired stations. The Interconnections-Batteries scenario (IB.x.1.0.a) will record similar results as the I.x.1.0.a case until 2030 when the costs increase reflects BESS's large-scale investments.

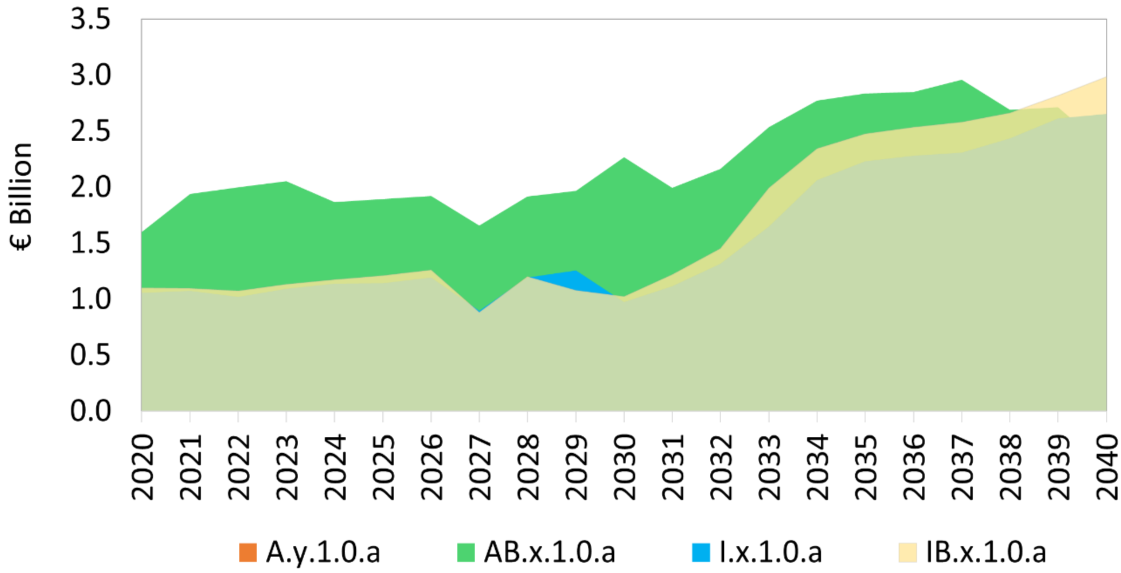


Figure 5.41: Annual total costs in the Greek islands' region – Principal scenarios

5.3.2 Regional levelised costs

Levelized cost is the total annual cost incurred divided by the regional generation. Figures 5.42 – 5.44 depict the regional levelised costs for two milestone years, 2030 and 2040, under the complete set of scenarios. That concerns solely electricity generated on the islands but not imported from the mainland. Autonomous systems have been split into three groups according to their size rated by the annual peak demand according to Table 1.1 in Section 1.3. The bar illustrates the range of the four principal Scenarios and the points the values of the sensitivity analysis.

Despite the general levelised cost-decrease trend, concerning the baseline pathway, the autonomous (A.x.) scenarios assuming the implementation of the imposed generation restrictions, experience multiple power outages which skyrocket local generation costs το 550 €/MWh on average by 2040. In general, the highest levelised costs occurs by the A.x.2.0 scenario, an exceptionally conservative reflection of the past. In addition, beyond the autonomous scenarios, IB.x.1.0.b, also generates some of the highest levelised costs at 350 €/MWh in the medium and small size islands due to minimum local generation. In contrast, the AB.x.1.2.b and AB.x.1.2.c scenarios assume rapid investments in storage and renewable capacity combined with high-efficiency measures in High_Eff, ISLA_EGI scenario leading to low levelised costs below 200 €/MWh. Finally, the I.x.1.2.a High_Eff scenario, one of the most cost-efficient options with 195 €/MWh among the wide range of scenarios, is deployed here. The IB.x.1.0.due to intensive capital investments, a relatively higher levelised costs than the rest of the Interconnection scenarios at 230 €/MWh. Nonetheless, such costs are gradually reduced.

In the Autonomous Pathway, energy efficiency measures through High_Eff, ISLA_EGI Scenario could bring down costs by 16%, whereas if the system is interconnected, costs drop by 9% in 2030. In 2040, the impact increases up to 18% in the Autonomous scenario, while it is reduced to 6% in the interconnected due to the high-RES penetration. On the other hand, the impact of a Low_Eff, ISLA_EGI Scenario would increase costs by 8% considering the Autonomous case and by 25% in the Interconnected case concerning small island systems, while for medium and large-sized, the impact is limited to 3-4%. By 2040, the energy efficiency impact is negligible compared to a BAU scenario for the autonomous case. In the interconnected context, costs are reduced by 2-3% in large and medium-sized systems and 8% in small, due to the large penetration of RES in the system.

The impact of fuel prices on islands is evident when LS oil is applied horizontally (A.y.1.0.d), recording an increase in generation costs by 10% compared to the BAU scenario A.y.1.0.a, with reduced impact for the rest of the scenarios. The combination of low-efficiency policies and the 'Current Policies' fuel scenario under A.y.2.1 would increase further costs by 10%. If the system becomes interconnected (I.x.2.1) costs increase up to 20% under the same conditions, combined with the absence of offshore wind projects. The assumption of an aggressive CO_2 emissions scenario in conjunction with a low oil price ‘sustainable’ scenario (A.y.1.2.b) would reduce the levelised costs compared to A.y.1.2.a, by 5-6%. By assessing only, the impact of carbon costs, the increase would range between 5 to 10% versus the A.y.1.0.a. In the interconnected context, a marginal increase in levelised costs of 1-2% is recorded in I.x.1.2.b mainly due to limited diesel fuel utilisation

Large electrical systems such as Crete and Rhodes record lower local levelised costs as they can deploy a wide variety of renewable projects compared to smaller systems. For Crete, the option to introduce locally natural gas facilities for electricity production but also for covering local heating demand (I.x.1.0.f) could prove a strategic decision with multiple economic benefits for the island. The levelised costs are reduced by 54% in 2030 and 24% in 2040 compared to I.x.1.0.a, reaching 91 €/MWh. In the long run, following 2040, such a trajectory would prevent submerging the third cable between Central Greece and Crete. It also stabilises the local grid between the Dodecanese islands and Crete while providing further independence. Nevertheless, it sustains Crete’s power generation dependency on fossil fuels. The Autonomous Pathway, including BESS (AB), tends to lower power generation costs to 113 €/MWh for the Rhodes system. Alternatively, the option to include battery units of 365 MW total capacity on the island while being interconnected could reduce the local generation costs to 139 €/MWh as it allows wind generation to increase by 50% compared to the I.x.1.0.a scenario ranging at 158 €/MWh by 2040.

Spatial limitations characterise some middle-sized systems to deploy large RES, while their dependence on other neighbouring systems and the NGS is critical. The exceptionally high costs of continuing the autonomy with generation restrictions will likely preclude these scenarios from the future energy landscape. Overall, the interconnection option with 158 €/MWh is judged as cost-efficient for the majority of the islands. The deployment of BESS while interconnected, would result in lower levelised costs for systems such as Chios, Kos-Kalymnos, Lemnos and Thera with an average value of 208 €/MWh in 2040 concerning that group of islands.

Small electrical systems present higher levelised costs mainly due to the large fixed costs linked to generator units in remote areas. Therefore, for such island systems, the option to continue autonomy only under the provision of enhancing the local network with BESS could be explored for Agios Efstratios, Serifos and Symi. Besides, other small islands Nisyros, Chalki, Telos, Irakleia, Koufonisi, Folegandros, being part of a broader island interconnection network, may host storage to improve reliability and increase intermittent RES penetration while reducing costs, as discussed previously. However, for the remaining small-sized systems, interconnection continues to be the optimal solution, with average costs of 134 €/MWh. At the same time, Ikaria and Skyros showcase cost savings at 1.2-4 €/MWh with BESS employment only when simultaneously interconnected.

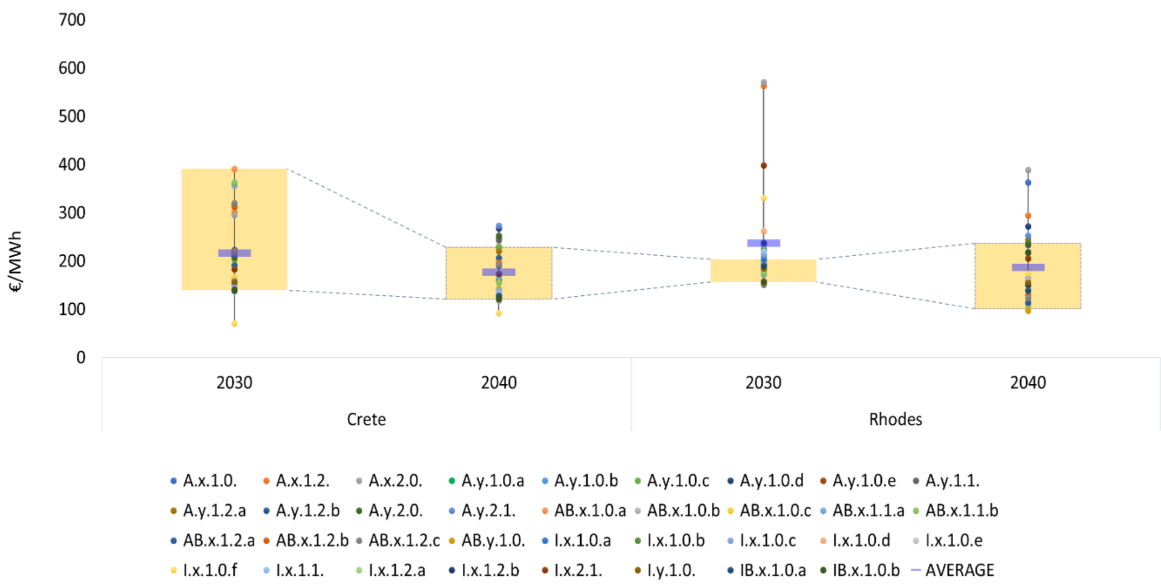


Figure 5.42: Levelized costs of energy produced by the large-sized island electrical systems for 2030 & 2040

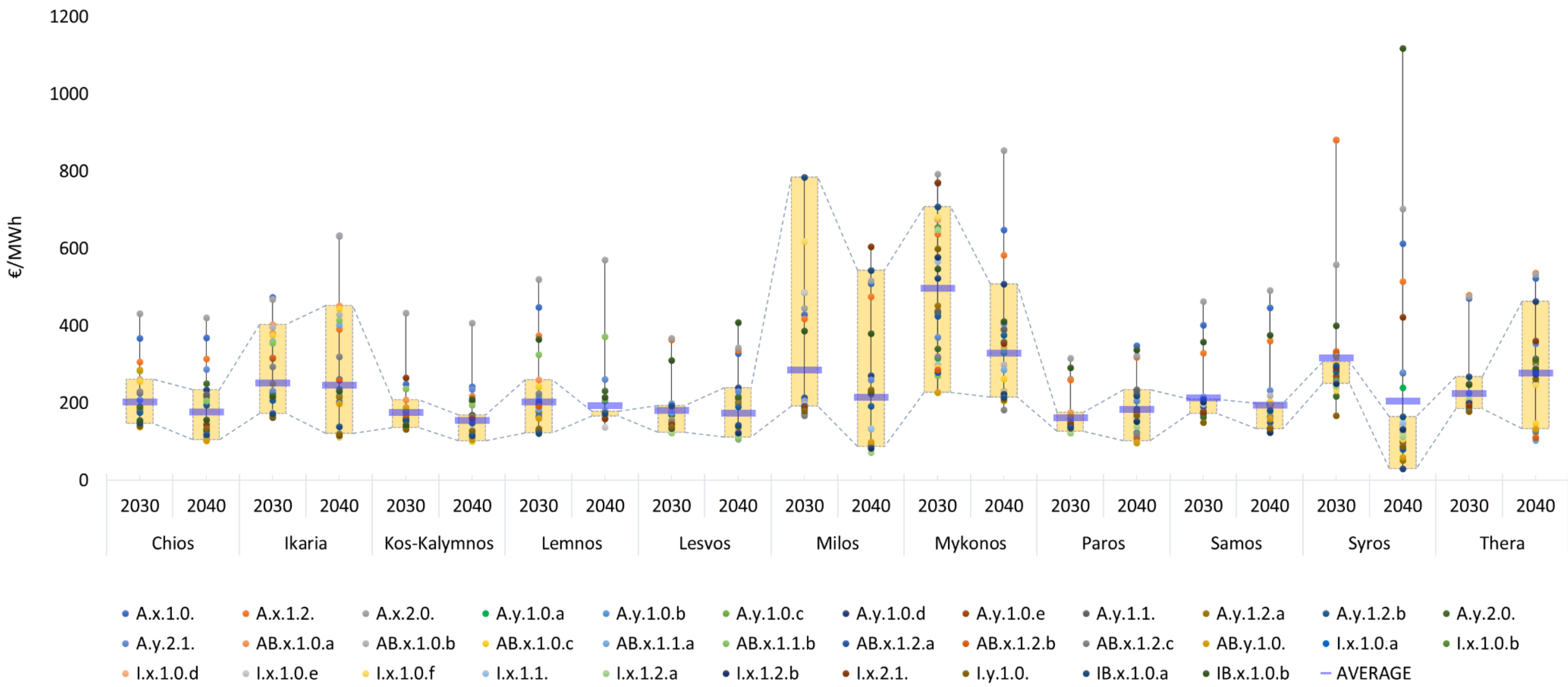


Figure 5.43: Levelized costs of energy produced by medium-sized island electrical systems for 2030 & 2040

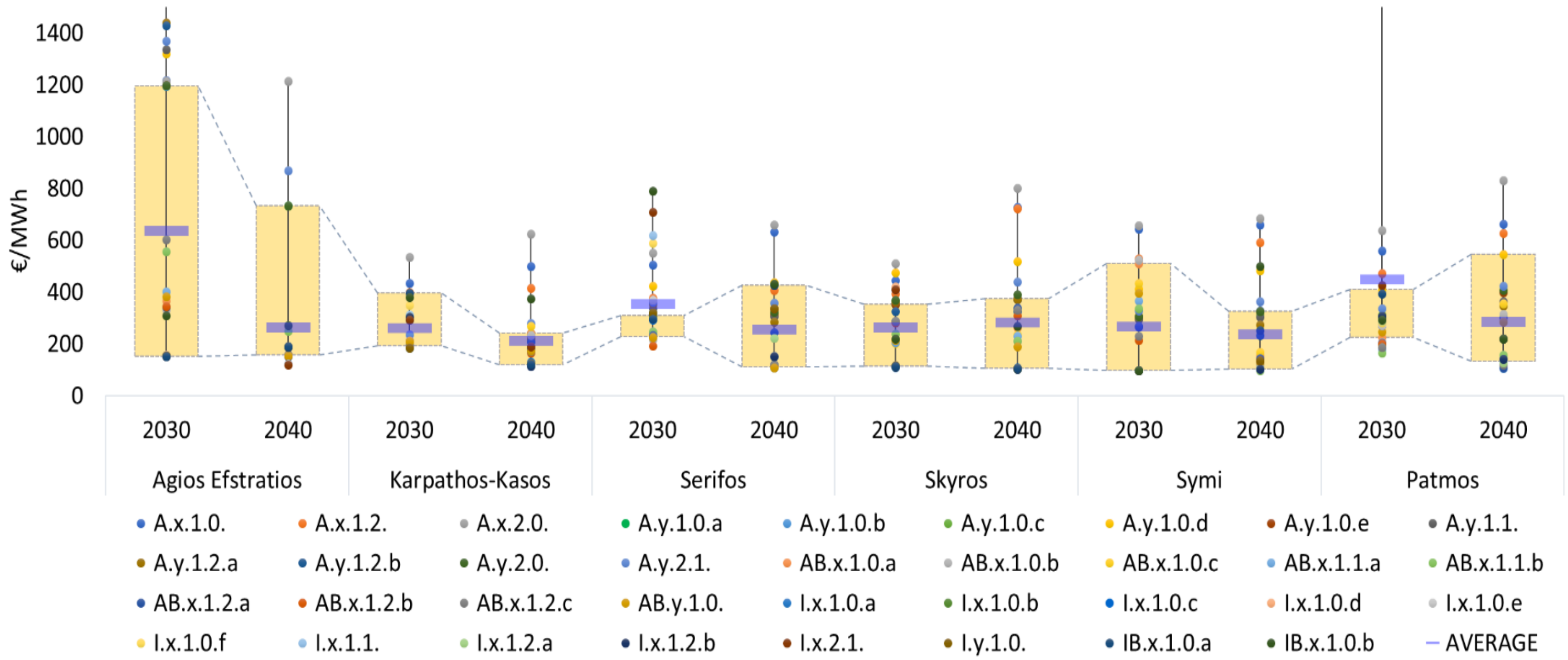


Figure 5.44: Levelized costs of energy produced by small-sized island electrical systems for 2030 & 2040

5.3.3 Power generation costs

The average generation costs at a regional level are calculated as the 'Total Local Generation Costs' divided by the 'Local Power Generation'. The hourly 'Price paid by the Load' is expressed as the SMP. The price has a single value applicable to the whole country at the NGS level. The divergence between the SMP and the average generation costs on the islands is subsidised through the PSO policy as described in Section 1.3.3.2.

During an average load week in 2030, generation cost fluctuations as depicted in Figure 5.45 are mainly driven by residential and services demand. In the baseline scenario (A.y.1.0.a), despite the significant min-max hourly discrepancies among the island electrical systems ranging between 360 and 100 €/MWh, the average daily trend shows relatively smaller fluctuations within the range of 223 and 195 €/MWh. The highest demand generation is recorded at the kick-off of the day around 6-7 a.m., while it increases again from 20:00 onwards when residents return home. Ikaria island, dependable on local hybrid storage systems, maintains relatively high costs during nigh-time due to the water pumping requirements. Furthermore, smaller islands such as Serifos, Skyros and Agios Efstratios record higher prices over night-time due to their inflexibility to shut down and start up the limited units operating on the island. The most significant gap between maximum and minimum values are evidenced in AB.x.1.0.a, It is observed that costs are reduced when there is a high solar PV contribution between 11:00 and 17:00. The highest values are encountered on islands such as Crete and Skyros, where oil-fired operation continues until 2030. The lowest is on the small Dodecanese islands and Agios Efstratios.

Costs are also impacted by Interconnections (I.x.1.0.a), which bring them down by 50% in 2030 compared to the Autonomous case at 102 €/MWh. When BESS are employed (IB.x.1.0.a) the average generation costs increase by 7 €/MWh compared to the I.x.1.0.a due to electricity price arbitrage and ancillary services provided by BESS. The hourly cost fluctuations are reduced under the interconnection scenarios due to the reliance mainly on wind and solar, ranging between 51 and 234 €/MWh. The average generation costs in the mainland experience minor discrepancies during the day with lower generation costs than those recorded in the islands' region, with an average value of 69-71 €/MWh.

When demand grows over summer, as a result of increased cooling and appliance consumption, the generation costs follow the consumption patterns more evidently, due to larger demand fluctuations over the day (Figure 5.46). Overall, costs increased by 6% compared to the average week in May in the autonomous context. This results from the use of expensive diesel-fired turbines to cover peaks unless the island operates only with a single type of fuel and generator which is the case for small-sized islands. Assuming the introduction of BESS in the system, costs decline by 30% compared to A.y.1.0.a and 11% compared to the spring as traditionally, there are strong winds and high irradiation levels in the region during August. In AB.x.1.0.a costs fluctuate between 45 and 405 €/MWh depending on the island system and whether thermal generation contributes to the electricity mix, while power outages are recorded on the mainland. In I.x.1.0.a. and IB.x.1.0.a the daily generation cost profiles show higher costs than the AVG week up to 380 €/MWh, however, the average prices of IB.x.1.0.a decline compared to I.x.1.0.a by 20 €/MWh. After 19:00, demand increases due to tourists' behavioural patterns, which tend to use electricity for showering, dining, air-conditioning and other uses such as catering purposes in restaurants and hotels, forcing the dispatch of oil-fired stations. The generation costs in the mainland slightly increase to 74-75 €/MWh. Also, increase in generation costs during morning hours affected by cooling demand and industry-related activities is evidenced.

In the MIN week, renewables cover a significant share of electricity demand, and as a result, the average costs drop by 10% in A.y.1.0.a (Figure 5.47). Nonetheless, the maximum values sustain with Agios Efstratios recording 363 €/MW, while Crete and Mykonos present a 40% reduction compared to the average week with a considerable potential to deploy renewables. In the Autonomous-Batteries case (AB.x.1.0.a), the costs vary significantly among the regions. Skyros island maintains the highest generation costs at 449 €/MWh due to the absence of wind energy until 2030, resulting in occasional power cuts. On the other hand, the Cycladic and Northern Aegean Sea islands succeed lower generation costs. At an average regional level, utility-sized BESS in autonomous systems could reduce costs by 28% during the winter compared to the BAU (A.y.1.0.a). The interconnection scenario (I.x.1.0.a) further reduces generation costs by 43% compared to the BAU case. Costs on the mainland fluctuate between 71 and 78 €/MWh, as the demand impact is less intensive compared to the islands, with the A.y.1.0.a scenario recording the highest costs. In the ultimate scenario (IB.x.1.0.a), coupling interconnectors with battery storage valorises the mutual benefits, and costs decline by 46%.

By 2040, the impact of interconnections and storage will be intensified (Figure 5.48). In the meantime, fuel prices grow, and renewables levelised costs reduce. If autonomy continues, generation costs increase by 23% in the AVG week compared to 2030, with prices as high as 450 €/MWh in small islands such as Agios Efstratios, Symi and Patmos. In AB.x.1.0.a, price fluctuations are smoothened during the day; nevertheless, costs increase exceeding 390 €/MWh in Skyros where diesel generators contribute in peaks. If interconnections are realised (I.x.1.0.a) the average local generation cost is reduced by 64% compared to the BAU case and by 5% compared to 2030 due to additional renewables entered into the local system. In IB.x.1.0.a generation costs decline further by 2% due to additional clean energy generation. In this scenario, the maximum costs are recorded during morning hours in both interconnection scenarios, reflecting older solar facilities realised between 2010 and 2020, maintaining higher tariffs. This result highlights the impact divergence of technologies according to the generation mix. At a national level, costs lower to 67-70 €/MWh as more renewables replace partially natural gas fuel generation.

Over the summer, the average generation costs reached 260 €/MWh as depicted in Figure 5.49 concerning A.y.1.0.a due to the demand and fuel prices, increased by 45 €/MWh compared to the respective season in 2030, whereas a smoother power generation profile is noticed under AB.x.1.0.a. In the Interconnection scenario (I.x.1.0.a), the generation costs do not increase compared to the average week. Under the IB.x.1.0.a, the benefits of an interconnected island network coupled with storage become evident for the whole island region, with 88 €/MWh average costs. Overall, small fluctuations are recorded during the day across all scenarios; however, the autonomous shows that costs are usually reduced around mid-day when solar PV peaks at its maximum performance. In the interconnection case, the lowest costs are recorded during evenings and night-time when traditionally imports from the mainland increase, with the wind being the predominant local source. Due to the intensified loads, generation costs in the NGS reach 102 €/MWh.

Over the winter of 2040 in the minimum wek, the autonomy maintains high generation costs with an average of 243 €/MWh (Figure 5.50). In the Autonomous-Batteries context, the average costs are reduced to 128 €/MWh. However, the upper limits in generation costs continue to be high due to instant peaks covered by thermal power stations. Nevertheless, this is a virtual cost reduction as battery storage proved that it could not suffice electricity demand in several NIIs. In the Interconnection Scenarios, the average generation costs range between 84 and 94 €/MWh in November, following the same patterns across the year. Overall, the 2040 annual cost reduction is 42% in IB.x.1.0.a against the A.y.1.0.a case.

The SMP at the national level constitutes the highest cost of the last required conventional unit entered in the dispatch order. Oil-fired units on the NIIs are assumed to cover their expenses through the PSO. The hourly price profiles for the NGS show a typical pattern of marginal increase during the early morning (7:00-9:00) and evening hours (18:00-22:00), with CCGT units usually representing the price-makers. In 2030, a price decline is recorded between the autonomous and the interconnected case, which maximises at 10 €/MWh during the average week loads benefiting from the cross-regional power flows exchange. The SMP fluctuates mainly between 45 and 65 €/MWh, with certain exceptions exceeding 100 €/MWh in high-demand evening peaks. During weeks recording maximum cooling loads, costs remain the same or marginally increase if BESS are not employed. In the winter months, a 6-7 €/MWh difference in the average SMPs is recorded between A.y.1.0.a and the Interconnection scenarios. The results show that there will be unserved demand at the national level under the autonomous scenarios and the interconnected case, resulting in high generation costs reflecting the VOLL of 3000 €/MWh (IPTO, 2021b). Such incidents are eliminated under the Interconnected Batteries IB.x.1.0.a scenario.

In the AB.x.1.0.a case that assumes high RES acceleration in the mainland and the islands; however, without effective regional interconnections for distributing renewables, negative prices are recorded between 10:00 and 13:00 due to the extensive PV penetration in the system and the relatively low demand. By 2040, in AB.x.1.0.a. negative prices are primarily evidenced during the summer, already from 9:00 a.m. It is worth noticing that such a phenomenon is eliminated by extending the transmission network to the Greek islands. The SMPs fluctuate among the scenarios and the seasons, with average weeks recording no considerable discrepancies. In contrast, in the summer months, costs increase if the islands become part of the interconnected network unless BESS systems are employed to counterbalance intermittent generation and take benefit of price arbitrage.

Finally, a decrease of 8 €/MWh is recorded over the winter in the SMP between the I.x.1.0.a and the IB.x.1.0.a due to the most expensive generator is dispatching power. This highlights the opportunity to reduce electricity prices if BESS systems balance demand and supply. Overall, despite the high integration of renewables, national prices rise by 10-16%, during the decade between 2030 and 2040, mainly because of the increased carbon and natural gas fuel costs which denote the ultimate price-makers, still representing 24-45% of the national generation mix.

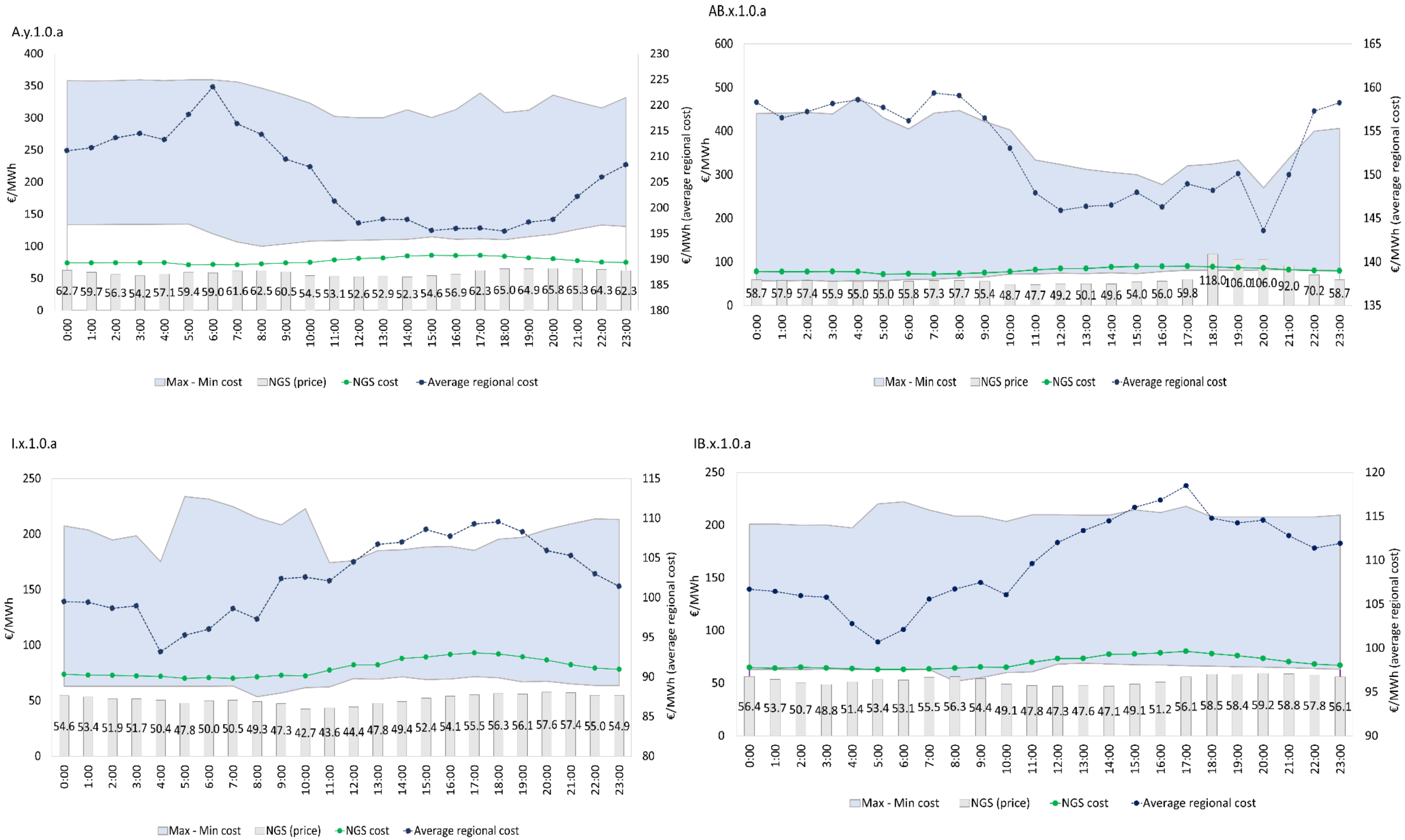


Figure 5.45: Average daily generation costs in the Greek islands' region and NGS prices for 2030 - Average load week

Figure 5.46: Average daily generation costs in the Greek islands' region and NGS prices for 2030 - Maximum load week

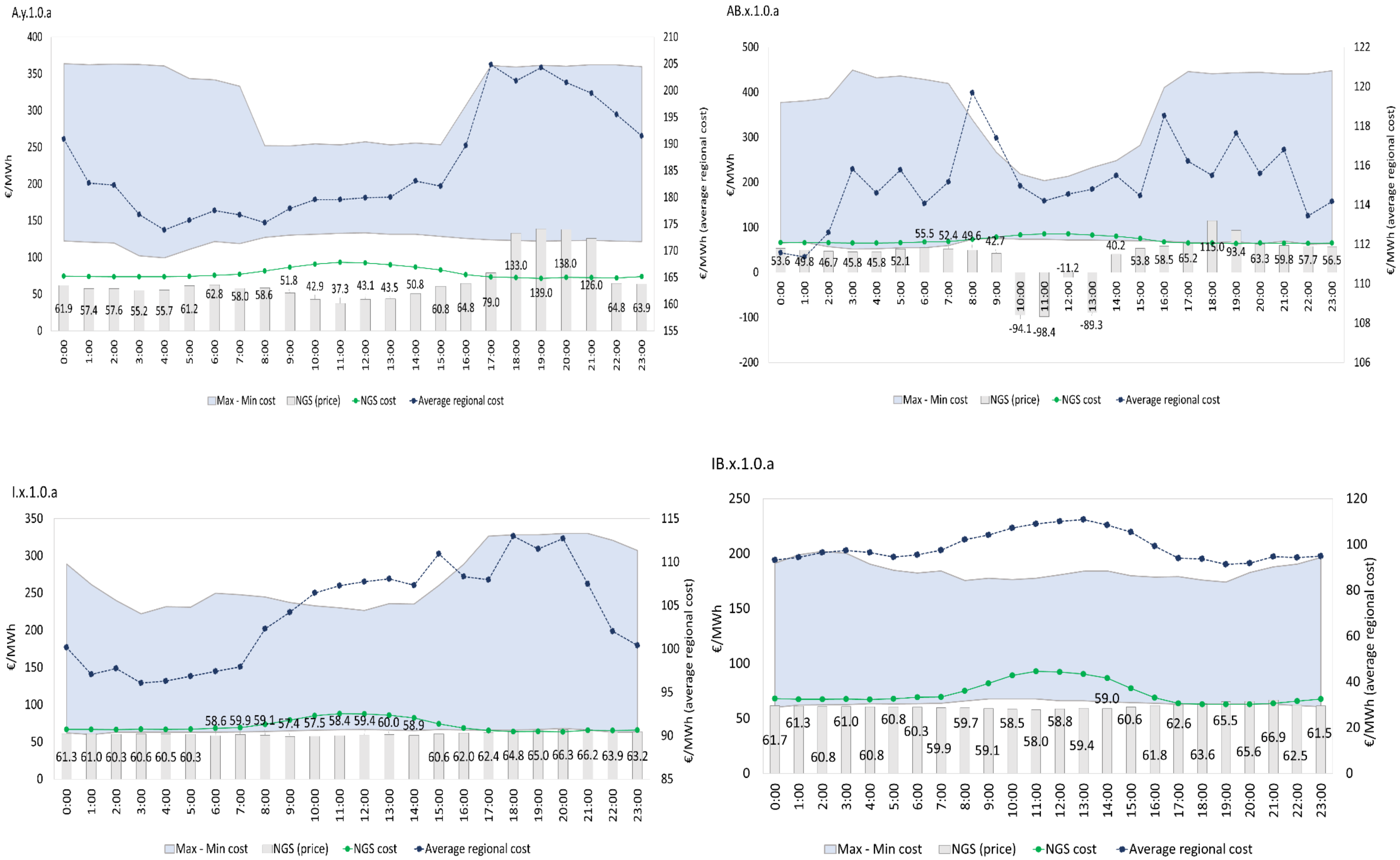


Figure 5.47: Average daily generation costs in the Greek islands' region and NGS prices for 2030 - Minimum load week

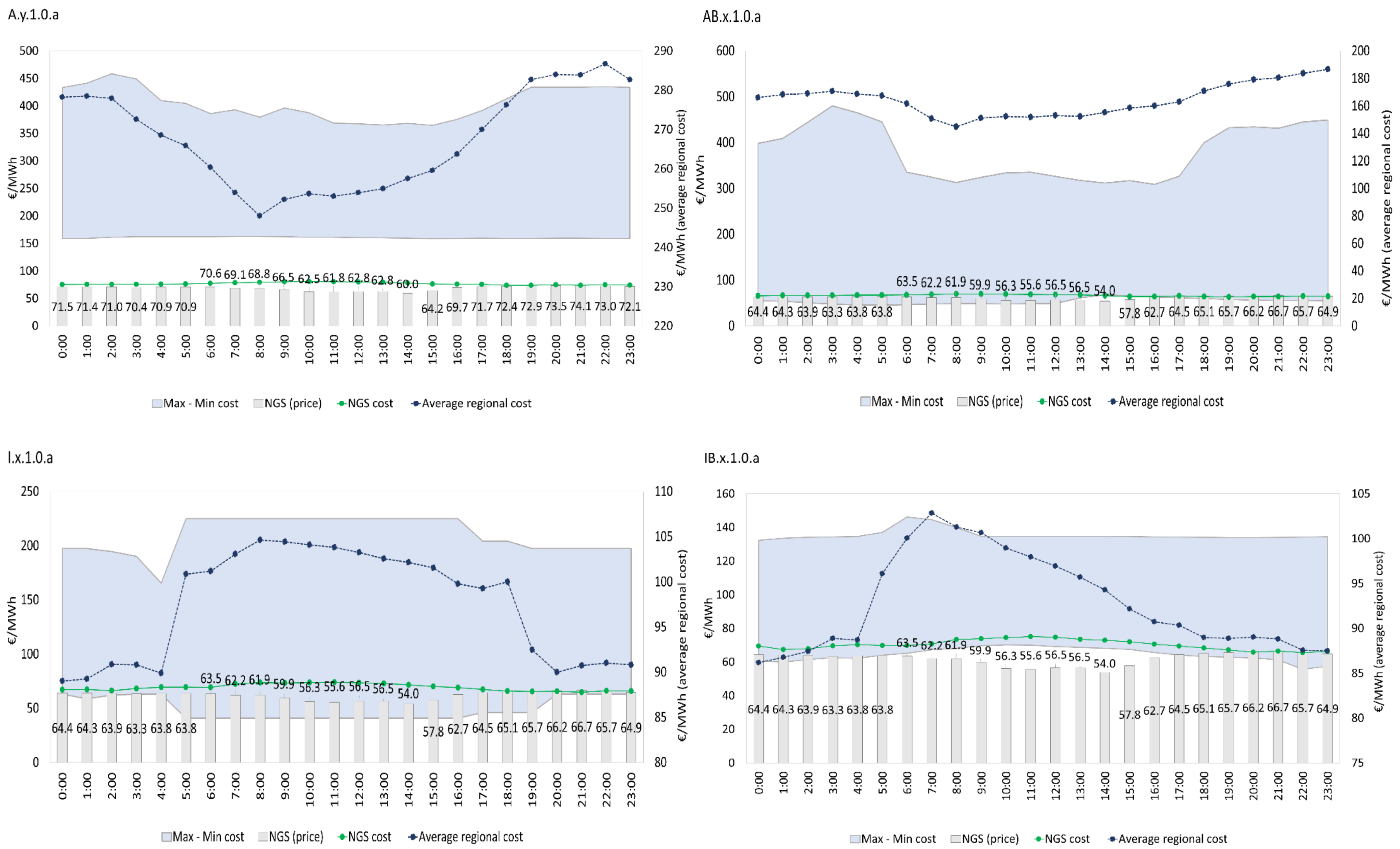


Figure 5.48: Average daily generation costs in the Greek islands' region and NGS prices for 2040 - Average load week

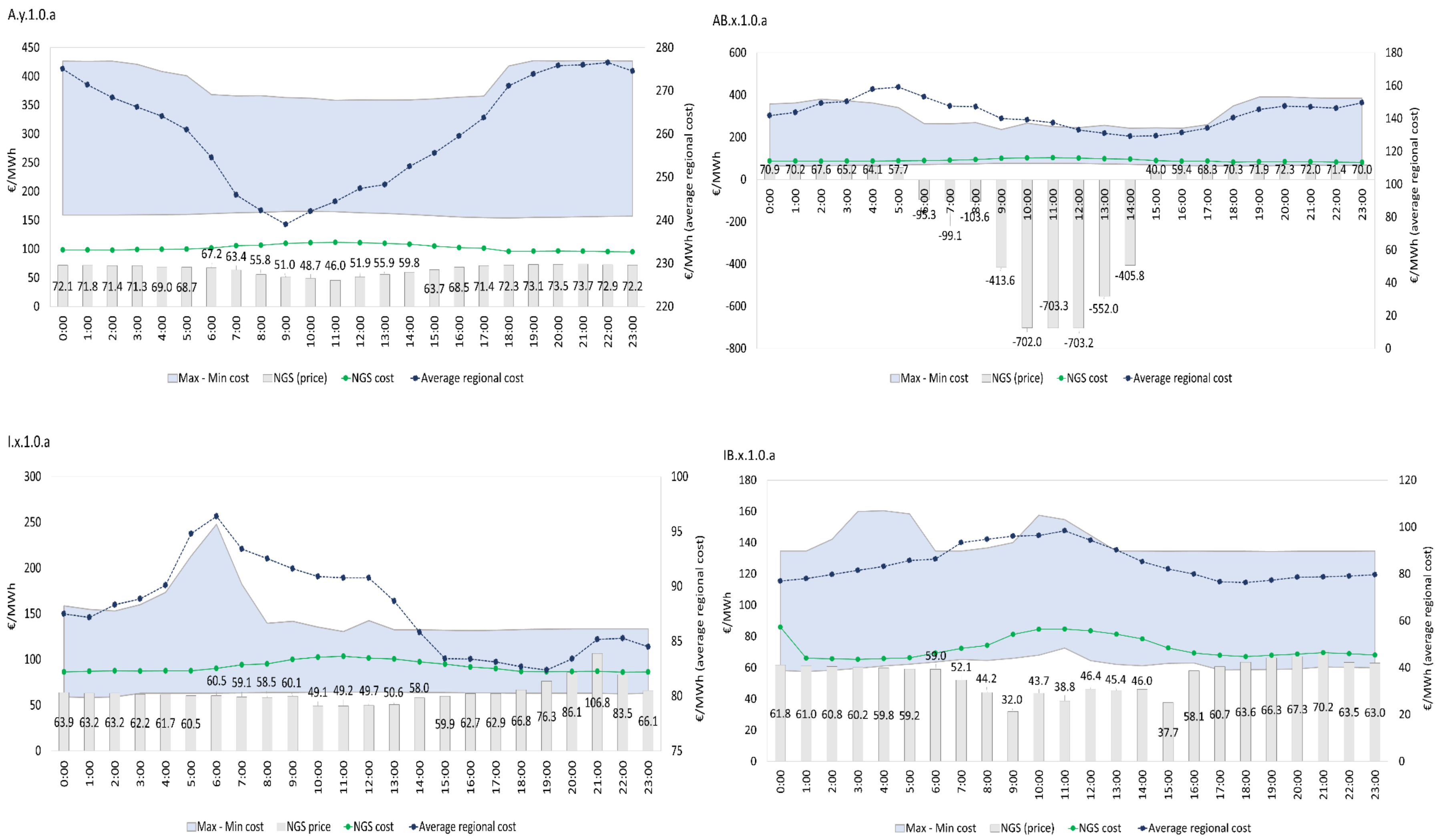


Figure 5.49: Average daily generation costs in the Greek islands' region and NGS prices for 2040 - Maximum load week

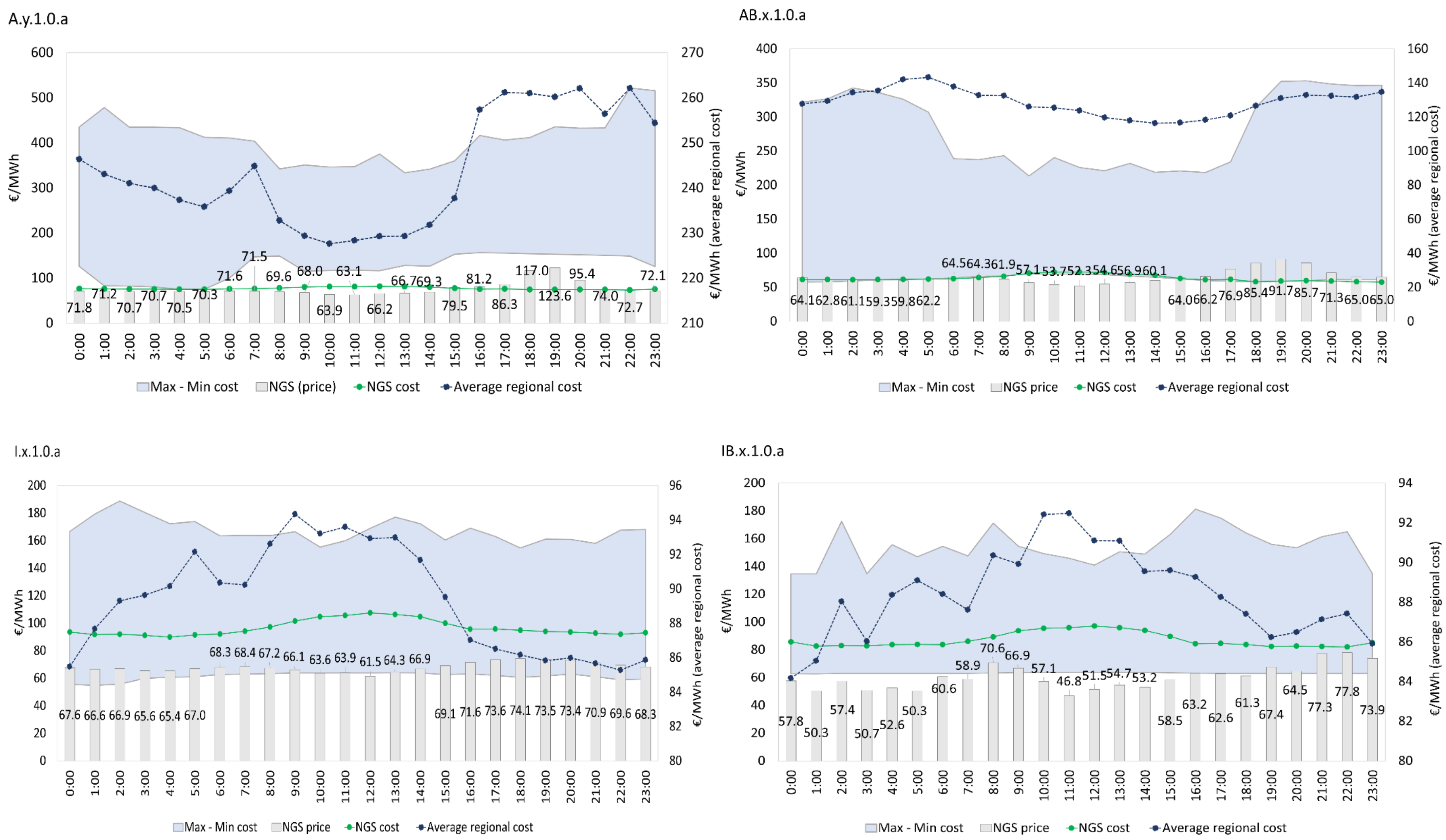


Figure 5.50: Average daily generation costs in the Greek islands' region and NGS prices for 2040 - Minimum load week

5.3.3.1 *EVs impact*

The integration of EVs shows that the lowest generation costs are usually recorded in scenarios charging during the valleys when the system is experiencing low demand levels. The EVs impact has been compared against a non-EV case. In 2030, improved performance is observed in the V2G scenarios for the Autonomous-Batteries S1 case, which succeeds to decrease generation costs up to 12% in the MAX week while dispatching electricity at competitive prices during daily peaks (Figure 5.51). V2G also reduces electricity costs by 6% over the AVG week. Concerning the rest of the scenarios, they demonstrate a tendency to increase costs mainly attributed to the dispatch of additional oil-fired capacity despite the successful operation of BESS. In the MIN week, almost 65% of the demand is already met by renewables, reaching their maximum potential. Therefore, the alternative to cover EVs demand is the thermal generation which increases costs by more than 28% regarding the public charging option and 23% concerning the unscheduled option.

Generation costs in 2040 are similarly affected by the type and quantity of thermal generation committed. The potential to reduce prices is observed especially during the average week, maximizing the operation of BESS, reaching 20% under the V2G-restricted case. On the contrary, considerable increases up to 25% are recorded over the minimum week as costs are already fluctuating at annual-low levels due to low demand and high-RES penetration with limited margin for further advancement. In addition, unserved demand quantities with a respective VOLL of 3000 €/MWh are observed across all weeks, amplifying the electricity generation costs.

Considering the S2 case, the generation costs increase further across most scenarios as it requires significantly higher dispatch of oil-fired generation to cover the increased charging demand. Notably, the public charging scenario records the highest increase of 31% in the minimum week. In 2040, the trends are escalated especially over the minimum and maximum weeks. Whereas in the average week demonstrating the highest prices in a non-EV case, more storage cycles are recorded, leading to a more efficient RES absorption. Hence, beyond the V2G and scheduled scenarios, morning charging also presents costs declining up to 18% in the average week.

Similar trends but contained in terms of intensity are evident in the Interconnection scenario (Figure 5.52). This case assumes the retirement of approximately 80% of the existing local capacity by 2030 and 92% by 2040. Therefore, EV charging is less dependable on thermal generation in the Interconnected state than the Autonomous. Under S1, most scenarios but the unscheduled, public and tourism drop costs up to 31%, mainly over the average week. During the maximum and minimum weeks, V2G and public scenarios attain a decrease of up to 12%. By 2040, the unscheduled and tourism charging scenarios strike with the highest increase in local generation costs, up to 27% over the maximum week, as thermal generation is becoming even more expensive on the islands’ systems. Once more, the V2G and morning scenarios demonstrate the potential for a marginal cost reduction of up to 14%.

Under an aggressive S2 case, the results fluctuate subject to the available dispatchable capacity in relation to the demand, however, a clear tendency for larger costs reduction is evidenced, benefiting from low-cost imports. The highest potential is observed over the average week, reducing costs by 30% in the V2G-restrcited case. However as almost the majority of the local installed oil-fired generators are phased out, unscheduled evening peak charging patterns and the majority of the charging scenarios in S2 will instantly force local thermal generation to be dispatched to avoid power shortages. In 2040, there is an increase across all weeks in most scenarios due to the incapacity to meet the entire EV charging demand from power flows imported from the mainland, forcing the operation of the thermal station as well as unserved demand. The maximum reduction of 13% under V2G in S2 is displayed in the minimum week, whereas none of the charging scenarios may lead to price reductions in the maximum week. Overall, the modelling outputs highlight that from an economic point of view unscheduled and public charging scenarios, if adopted as principal strategies, will lead to considerable increases in generation costs over the year. In contrast, V2G and scheduled charging patterns succeed in reducing costs across most scenarios.

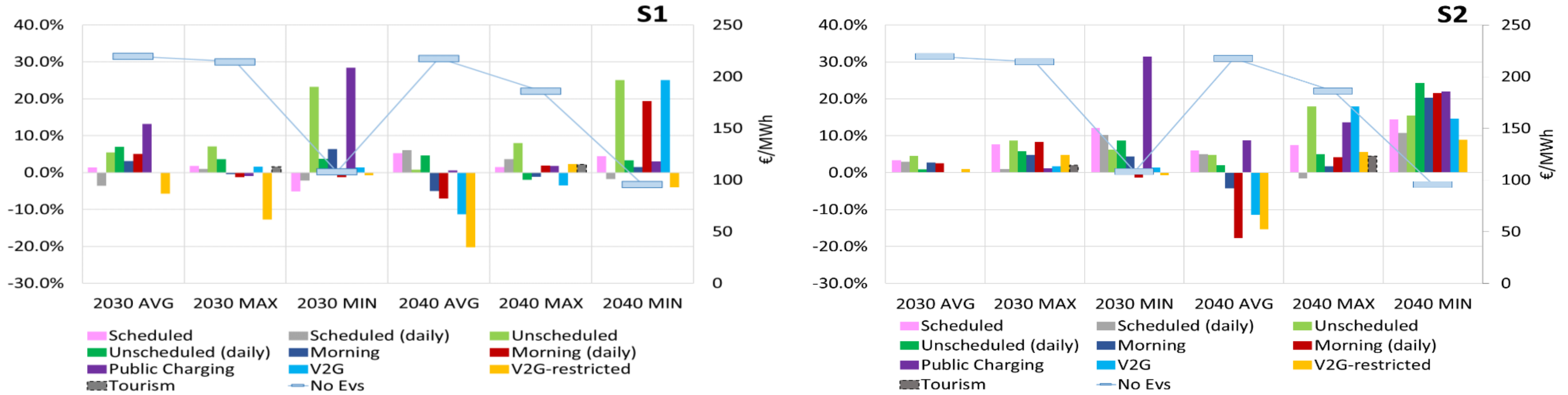


Figure 5.51: EV charging scenarios economic impact (X-axis) vs No-EVs baseline (Y-axis) – Autonomous Batteries (AB.y.1.0)

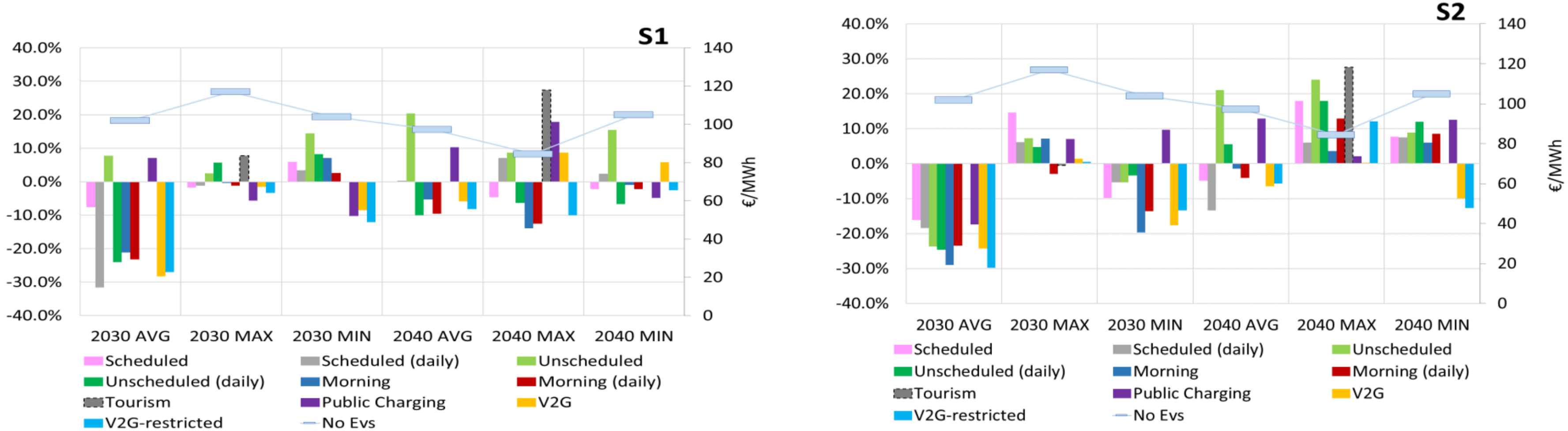


Figure 5.52: EV charging scenarios economic impact (X-axis) vs No-EVs baseline (Y-axis) – Interconnection (I.x.1.0.a)

5.3.4 Public service obligation

Despite the high-power generation costs produced in the non-interconnected islands region by oil-fired generators, all customers supplied power in the Greek territory are subject to equal electricity charges subsidized by the Greek state through electricity consumers' electricity bills via the Public Service Obligation Policy (PSO). Overall, the PSO subsidisation policy has adversely impacted the Greek environment and economy as there has been little motivation from the islanders' side to move towards energy efficiency and clean energy solutions.

The PSO was calculated for every autonomous electrical system according to Eq. 1.3, considering the monthly average generation costs (variable and fixed) from local oil-fired units, the SMP, as well as the respective generation from conventional and renewable energy sources. Data were extracted from PLEXOS for the full projection horizon from 2020 to 2040. Concerning the UoC charge, it is paid directly by the electricity consumers on islands (described in Eq. 1.5 and Eq. 1.4), using outputs extracted from the ISLA_EGI model. The Low_Eff and High_Eff and the BAU scenario from the literature were included while considering the following data:

- The projected number of households per transmission region (R) per year as extracted from ISLA_EGI model is described in Section 3.3.5.1;
- The projected number of hotels per transmission region (R) aligned with the tourism assumptions used in ISLA_EGI model (Hellenic Touristic Organisation, 2018);
- The number of public and other commercial buildings (Hellenic Statistical Authority, 2012a);
- The average kVA for public and commercial buildings as specified in Hellenic Republic - Ministry of the Environment and Energy (2017d);
- The average kW per person for touristic accommodation (hotels, rooms to let) - data were provided per room. Two persons per room were assumed as specified in Hellenic Republic - Ministry of Tourism (2011);
- The annual residential consumption as produced by the ISLA_EGI model;

- The annual consumption of public and services sectors as produced by the ISLA_EGI model;
- The days are 365;
- The regulated charges for consumers are split into fixed and variable costs provided as specified in RAE (2021), assuming an annual increase equal to the inflation (+0.8%);
- For industrial facilities, as they represent a minimal share of the annual electricity demand and their number is unknown, we assumed only the variable costs multiplied by the annual consumption as extracted from ISLA_EGI model.

The total PSO concerning the A.y.1.0.a per examined autonomous electrical system is presented in Figure 5.53. Furthermore, the aggregated values concerning the rest of the autonomous scenarios are depicted, highlighting the importance of energy efficiency and fuel prices in the configuration of the PSO charges. The pathways such as the AB, I and IB assume that high capital incentive investments envisioned under these trajectories will not entail further subsidy costs following 2030. In parallel, the limited impact of RES integration in the Autonomous Pathway is observed. Notably, the A.y.1.0.d scenario presents the highest costs at 1.5€ billion in 2030 and 1.9€ billion in 2040 versus 1.3€ billion and 1.5€ billion respectively in A.y.1.0.a, due to the extensive use of low sulphur oil fuel. This increase is recorded despite the interconnection of the Cycladic islands leading to PSO costs reduction only in the Paros electrical system. On the other hand, the autonomous scenario with the lowest cost is A.y.1.0.e followed by A.x.1.2. In A.y.1.0.e, natural gas is introduced on Crete, allowing an average reduction of approximately 40% in Crete's PSO compared to the A.y.1.0.a scenario. In A.x.1.2, restrictions limit thermal production while ambitious energy efficiency measures support the system. Nevertheless, such a scenario would inevitably lead to severe power outages.

At the 20-year level, energy efficiency through the High_Eff ISLA_EGI model could lead to 4.8€ billion savings, while if an even more aggressive carbon price is adopted, the savings can be maximised to 5.7€ billion. The region experienced

110% growth between 2020 and 2040 concerning PSO charges, which escalated to more than a 230% increase compared to 2016. This is translated into a 12% increase in the system and 38% in regional average generation costs. Particularly, Thera is expected to increase its PSO charges by 390% due to significant tourism growth. On Crete, Skyros and Ikaria, the increase ranges between 79 and 48% due to high-RES penetration supported by the local hybrid system. Between 2030 and 2040, the average PSO increase is limited to 14%, while systems such as Skyros, Paros and Agios Efstratios experience a reduction in PSO due to enhanced RES penetration. On the whole, PSO charges fluctuate close to 22€ billion costs for the whole projection horizon.

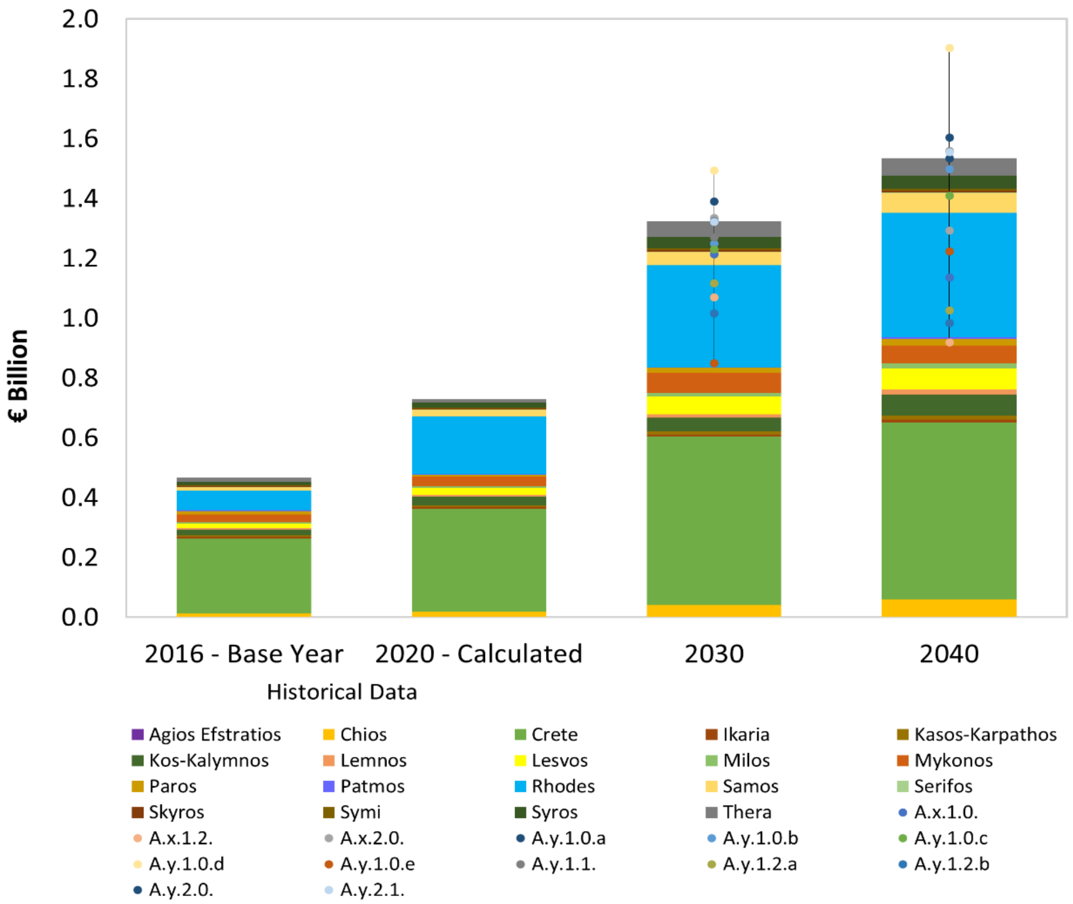


Figure 5.53: PSO levy for the AES

5.4 Environmental Sustainability

5.4.1 CO_2, NOx and SO_2 emissions

5.4.1.1 *System level*

Electricity and heat production are responsible for one-third of all CO_2 emissions. Also, they are the largest SO_2 and second-largest NO_x emissions source after transport (European Environment Agency, 2013). The ETI environmental performance among the various scenarios is measured in CO_2-eq emissions. Under all principal scenarios, emissions have experienced a declining trend (Figure 5.54). Between 1990 and 2016, little progress has been made, merely reaching a 20% drop. Given the latest available data in 2019, there has been a marginal increase of 2% compared to 2016 due to improvement in the economic conditions. Nevertheless, considering the ambitious targets for 2030 and 2040 announced under the NECP (Hellenic Republic - Ministry of the Environment and Energy, 2019b), a rapid reduction is anticipated over the coming years attributed to RES acceleration combined with energy efficiency measures.

During the 2020-30 decade, the scenario which is expected to drive down emissions is the Autonomous-Batteries (AB.x.1.0.a), stressing the fact that since 2020 rapid deployment of renewables could reduce cumulative emissions by 48 $MtCO_2eq$ compared to the A.y.2.0 pessimistic scenario and 44 $MtCO_2eq$ compared to the baseline A.y.1.0.a. In 2030, when the transmission extensions in the Greek islands' region are expected to be completed, the Interconnection scenarios will take the lead in reducing emissions by 70-71% versus the baseline year 2016, whereas the Autonomous Battery scenario will record a 67% reduction. The additional emissions reduction succeeded by the IB.x.1.0.a scenario is translated into a 55% discrepancy between the autonomous and the interconnected pathway. As such, the only principal scenario merely reaching the ambitious 2030 national emissions targets of 7 $MtCO_2eq$ is the IB.x.1.0.a. If sensitivity analysis is applied, I.x.1.2.a succeeds in lowering emissions at 7.1 $MtCO_2eq$. These targets translate into an almost 80% reduction compared to 1990 levels, set as the baseline year by the United Nations (E3MLab, 2009), when the target for the whole energy sector has been set at 55% at the EU level (European Commission, 2020a).

By 2040, the expected decline thanks to the Interconnection scenarios is 74% higher than the BAU trajectory, which reduces emissions to 46% compared to 2016 and 56% compared to 1990. Overall, the Interconnection scenarios accomplish emissions reduction by 82% (I.x.1.0.a) and 86% (IB.x.1.0.a) while the AB.x.1.0.a restricts the progress to 74% compared to the baseline year 2016. In contrast to the 1990 levels, the reduction shows a decline of 89% under the Interconnection-Batteries (IB.x.1.0.a) scenario, 86% considering only interconnections (I.x.1.0.a), 79% under the Autonomous-Batteries case and only 56% under the BAU. As before, the IB.x.1.0.a is the only scenario seeking to reach those targets aiming at 4 $MtCO_2eq$ in 2040 and eventually zero emissions by 2050 (Hellenic Republic - Ministry of the Environment and Energy, 2019c).

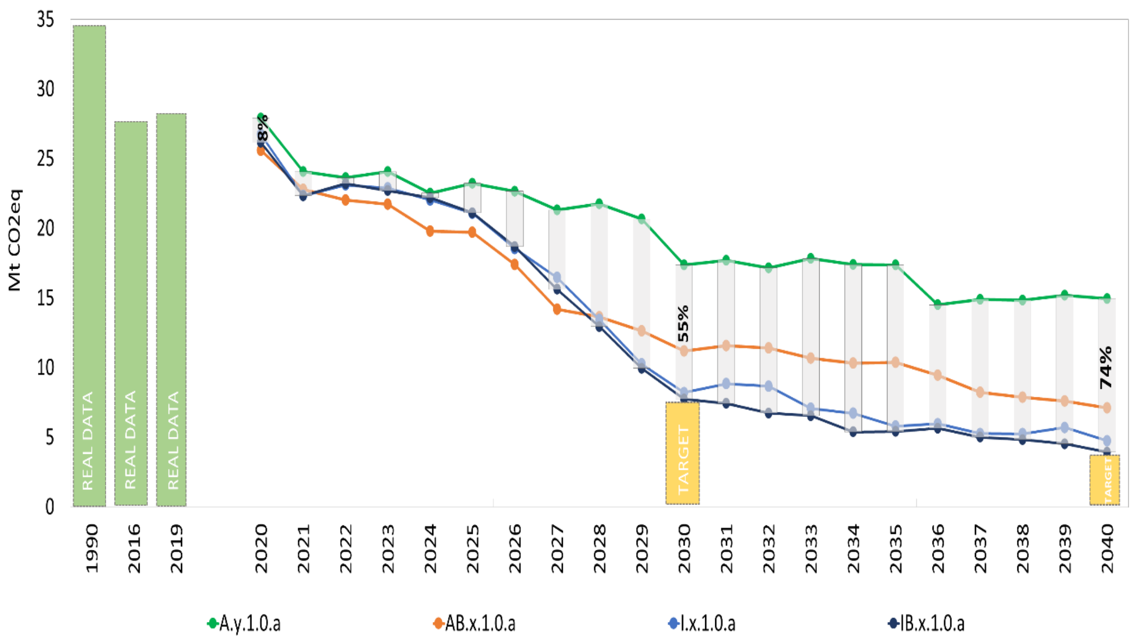


Figure 5.54: CO_2eq emissions at the system (national) level - Principal Scenarios

5.4.1.2 *Sensitivity Analysis*

Figure 5.55 highlights the importance of both supply and demand sectors for driving emissions down at the regional level through cumulative emissions results for 20 years. In the Autonomous-Batteries Pathway (AB), the islands represent 6% of the total national emissions releases compared to 14% in the A.y.1.0.a. The most efficient scenario is the High_Eff, ISLA_EGI demand profiles, i.e. AB.x.1.2.a with cumulative figures of 20.5 $MtCO_2eq$. In this context, the difference between the BAU demand pathway is marginal, equal to 3%. This is explained due to the rapid and massive RES employment from 2020 to support the supply gap due to oil usage restrictions. Energy efficiency plays a catalytic role when oil generation restrictions are not imposed, recording a 27% reduction in the Autonomous case (A.y.1.2.a) compared to A.y.1.0.a. Limitations in the oil-fired capacity factors (A.x.1.0.) bring down emissions by 35%, however without the necessary renewables capacity deployment to fill the supply gap.

The scenario comparison shows that the interconnection infrastructure will most effectively reduce operational emissions without considering lifecycle emissions analysis. Particularly, top-ranking scenarios adopt a low carbon intensity electricity mix such as the I.x.1.0.f (12 $MtCO_2eq$) assuming the introduction of natural gas fuel for electricity purposes in Crete already in 2020, eliminating oil usage resulting in the lowest emissions at the national level. The High_Eff demand scenarios as produced by ISLA_EGI model, range between 16 $MtCO_2eq$ (1.x.1.2.a) and 20 $MtCO_2eq$ (1.x.1.2.b) for the Interconnected case, which translates into an average annual amount of 0.8-1 $MtCO_2eq$. The comparison between 1.x.1.2.a and 1.x.1.2.b underlines that a further increase in carbon prices in a sustainable energy context where fuel prices drop would not trigger more renewable investments than the mainstream carbon pricing scenario. Energy efficiency (I.x.1.2.a) reduces CO_2eq emissions by 16.5% compared to I.x.1.0.a. Among the Principal scenarios, the one showcasing the lowest carbon emissions impact is the IB.x.1.0.a (16.6 $MtCO_2eq$) recording a 74% reduction compared to the BAU A.y.1.0.a with 64 $MtCO_2eq$ and 98% compared to 2016. In 2040, the gap between the two scenarios will exceed 99%. In the interconnected context, emissions on the islands represent only 3 to 7% of the total national emissions.

The interconnection of Crete would trigger significant carbon reduction by 21 $MtCO_2eq$ over the two decades with a limited BESS impact. Crete is followed by the second-largest emitter, Rhodes, which achieves 6 $MtCO_2eq$ emissions decline if it becomes interconnected and 10 MtCO2eq if batteries are introduced, reducing its emissions by 98%. Once it becomes interconnected, Rhodes requires a certain generation to supply the rest of the Dodecanese islands connected through Crete. Therefore, battery storage on the island of Rhodes is deemed essential for balancing the interconnected regional system while reducing further emissions by 1 MtCO_2eq.

Among the rest of the islands, those achieving the most noticeable emissions decline to exceed 70% against the BAU cases when they become interconnected are Samos, Lesvos, Milos, Mykonos, Paros, Syros and Serifos, since they achieve to green their energy portfolio. On the other hand, islands such as Ikaria, Kos-Kalymnos, Symi and Lemnos achieve carbon emissions reductions compared to the BAU pathway lower than 60%. This is mainly attributed to their current RES capacity, already installed with a relatively 'smaller margin' for improvement. Overall, the electrical systems that could play a critical role in decarbonising the whole island region are mainly Crete, Rhodes, Chios, Samos, Lesvos and Paros, which are big enough to host large-scale RES projects.

CO_2eq costs at the national level follow a similar trajectory as the released emissions. The scenarios producing the maximum emissions burden also the highest carbon costs, starting from the IB.x.1.0.b with more than 27€ billion costs for the two decades. Overall, the Interconnection Scenario records the lowest costs with an average value of 9.3€ billion or 0.47€ billion per year. The I.x.1.2.a, considering the High_Eff ISLA_EGI demand path and the I.x.1.0.f introducing NG on Crete is anticipated to incur the least possible carbon costs below 8.9€ billion as well as the lowest emissions. The Interconnection-Batteries scenario (IB.x.1.0.a) also records some of the lowest emission cost levels at 9.2€ billion. The results stress that scenarios assuming non-low Sulphur fuels (e.g., I.x.2.1, A.y.2.0, etc.) will experience slightly higher costs ranging between 1 and 2€ billion due to relatively higher emissions than the Principal scenarios. The scenarios incorporate the aggressive CO_2 emissions forecast, such as I.x.1.2.b, AB.x.1.2.b etc., trigger lower carbon-intensive fuel combustion investments, reducing carbon costs.

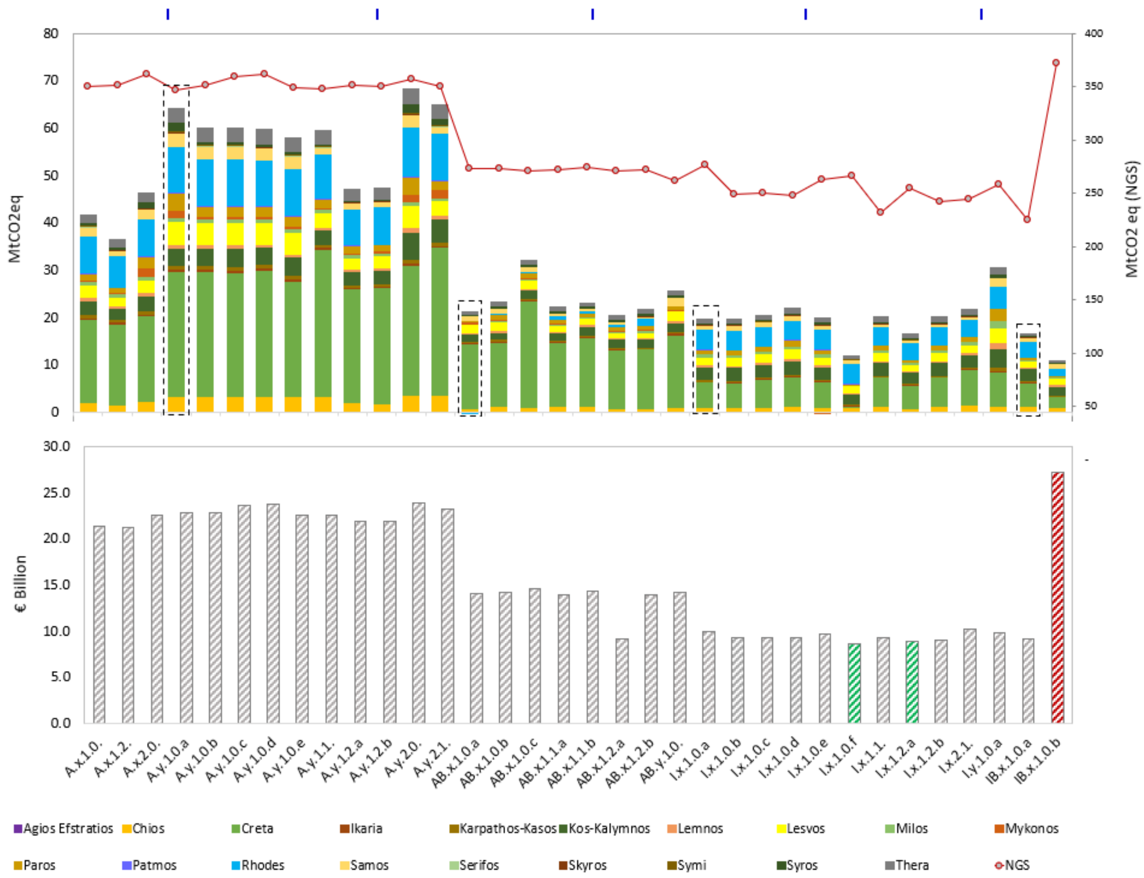


Figure 5.55: Cumulative (2020-2040) CO_2eq emissions and costs in the Greek islands' region – Sensitivity analysis

5.4.1.3 *Intensity*

Beyond the total amount of CO_2eq emissions released, the impact of RES reflects on the carbon emissions intensity, irrespective of the energy efficiency dimension. A negligible difference between 2016 and 2019 is observed due to their proximity. However, carbon intensity is expected to be reduced by 44% in 2030 under AB.x.1.0.a (Figure 5.56). The Interconnection scenarios follow with a 30-35% reduction as they signal the massive RES deployment post-2030 when all interconnections will be realised. By 2040, it will become evident that the IB.x.1.0.a scenario seeks to reduce carbon intensity in the islands region to 77 kg/MWh, an 88% improvement versus 2016.

During the first decade, carbon intensity is lower in the mainland than in the islands region across all scenarios except the AB.x.1.0.a. This foresees higher renewables and storage deployment. In the Interconnected case, up till 2030, the NGS requires additional generation capacity to export power to the islands' region. This may be achieved by building new RES or NG to replace lignite. As such, the Interconnection scenarios seek to reduce intensity by 120-125 kg/MWh compared to the BAU (A.y.1.0.a) and 240-300 kg/MWh compared to 2016, translated into a 36-47% decrease. Alternatively, the AB.x.1.0.a scenario lessens the carbon intensity by 34%. Despite the autonomy, low sulphur requirements in this pathway shift generation in the mainland to renewable sources, irrespective of RES growth in the islands' region. By 2040, the reduction in carbon intensity is mainly intensified in the Interconnected case (I.x.1.0.a), resulting in 55% in the mainland. However, the IB.x.1.0.a scenario continues to be the frontrunner with 260 kg/MWh, approximately 58% lesser than in 2016.

In 2030, there will be a decline in NO_x and SO_2 emissions ranging between 25 and 27% for the AB.x.1.0.a scenario and 8-18% for the two interconnection scenarios versus the 2016 levels. By 2040, the most impactful results will be recorded in IB.x.1.0.a with 88% reduction. For the rest of the scenarios, the intensity decrease ranges between 45% and 60%. Concerning the Autonomous Scenario, the results show no considerable variance between 2016 and 2030 levels; however, by 2040, a decrease in the order of 30% is anticipated. Non-CO_2 emissions have recorded higher values in the NGS than in the islands' region. One of the most powerful indicators for reducing NO_x and SO_2 emissions is the delignification of the Greek power system, reducing their intensity in 2040 by 35% and 32%, respectively, relative to 2016. While the A.y.1.0.a scenario assumes the continuation of lignite-fired generation until 2040 at limited levels, batteries deployment, and interconnectors among the Greek islands effectively reduce non-CO_2 emissions alongside the policy context they evolve. Overall, in IB.x.1.0.a this reflects a 59% decline for NO_x and 71% for SO_2 compared to 2016 concerning the NGS.

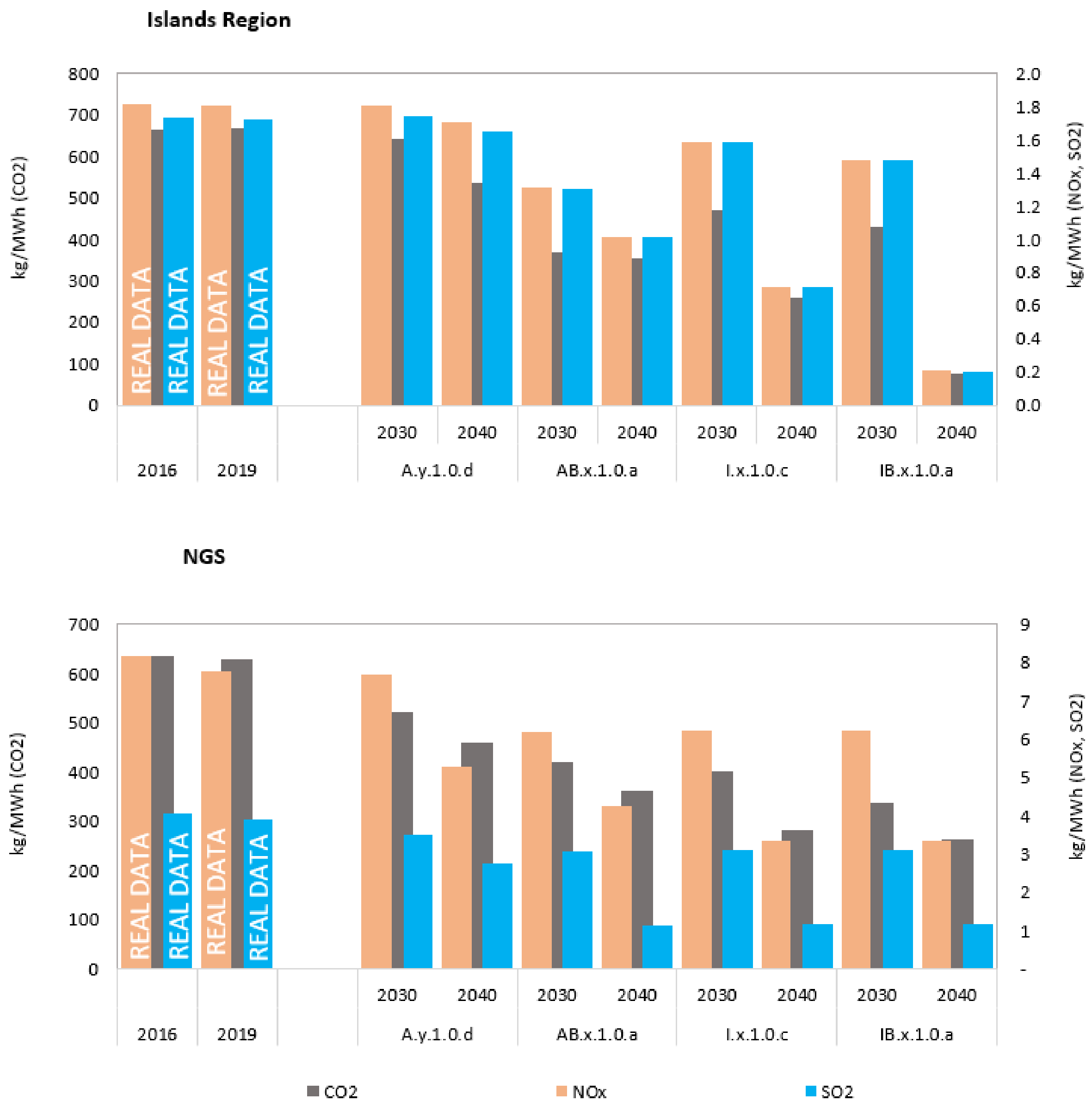


Figure 5.56: Total CO_2, NO_x, SO_2 emissions intensity for the Greek islands' region and the NGS - Principal scenarios

5.4.2 EVs impact

5.4.2.1 *Electricity System*

The electrification of the transport sector is meaningful only when the electricity mix consists of low-carbon intensity fuels, which will eventually reduce the carbon emissions from transport uses. Regarding energy autonomy in 2030, there is a relative increase in CO_2eq emissions from EVs deployment in S1, going as high as 26% in the minimum week across most scenarios (Figure 5.57). The discrepancies between the weeks can be explained as there is a higher margin for stored energy during the average and maximum weeks to be dispatched due to the significant thermal capacity already committed. At the same time, a smaller relative increase is recorded over the winter months, represented via the minimum week. The V2G-restricted charging strategy is excluded as it reduces emissions by 5.5% by reinjecting clean energy into the grid.

In 2040, the scenery changes for average-load weeks as there is a margin for up to 9% emissions reduction across several scenarios such as the morning and V2G. This is achieved while allowing higher amounts of stored and dispatchable renewable energy to cover charging demand. No emissions reduction is attained over the maximum and minimum weeks as an additional conventional generation will be committed. Despite a relative increase in renewables share in the electricity mix during wintertime, emissions rise to 44%. Bidirectional charging keeps emissions at levels below the BAU scenario through the same season. Emissions intensities are reduced across all scenarios except for the Tourism scenario. Remarkably, the minimum week records the most prevalent benefits if a V2G strategy is adopted.

Under S2, the increase of emissions is higher, proportional to the additional loads that trigger the dispatch of thermal generation across most scenarios. Exceptions are the V2G and scheduled scenarios in the maximum week and the morning daily scenario in 2040, which allow for an additional renewable generation. The biweekly scheduled scenario will inevitably increase CO_2 emissions up to 37% in the minimum week due to committing thermal units that would be inert otherwise. Similar conclusions are drawn for the biweekly morning charging scenarios, especially in 2040, having a minimal benefit from an environmental point of view between 10:00 and 16:00, as there is limited RES excess that could be absorbed. At the same time, most of the charging demand is met by oil-fired generation units already committed, making their start-up and shut down unfordable, particularly on large-sized island systems. Nonetheless, the overall carbon intensity for the power generation mix is reduced during weeks with average loads fluctuating in the maximum weeks. Finally, in the minimum week, CO_2 intensities are increased by almost 100% across all scenarios.

In the Interconnected case, the impact of electric mobility on the islands' region takes nationwide dimensions as a significant amount of demand is met by imported energy. Hence, the implications at the local and country level are also investigated. According to Figure 5.58, specific scenarios such as the scheduled daily and V2G result in emissions reduction up to 12.5% in 2030. They support RES growth while eliminating curtailments with local dispatchable renewable generation capacity. On the other hand, the unscheduled and morning scenarios will require larger amounts of imported energy, increasing the regional emissions level to 7% for the minimum week. Lower levels of emissions augmentation are recorded during summer, containing 3% for all peak charging profiles, including the Tourism scenario. By 2040, the majority of the available generation capacity on the Greek islands will consist of renewable energy, with no margin for significant discrepancies. As such, despite the instant dispatch of thermal generation in some extreme peaks, more renewables are dispatched while improving the overall generation mix. Among all scenarios, those with the most impressive results footprint are the V2G scenarios that could benefit from coupling energy storage with interconnectors while recording emissions reductions up to 5% in 2040. A reduction in carbon intensity is achieved across all charging options, except for the peak scenarios over the summer months.

Considering the S2 Scenario, emissions follow the increasing trends of the charging demand loads; therefore, they will grow across several charging plans in 2030. Exceptions concern primarily the V2G-restricted scenario, which caters to the local energy system requirements while reducing emissions by 5.7% in the average week. Additionally, the morning daily scenario in the maximum week exceeds 9% reduction. The local emissions are reduced horizontally during the winter compared to a non-EV scenario, except for public charging. This is achieved through the abundance of local renewables while reducing the exported energy. Similarly, in 2040 when more renewables are added to the system, emissions decrease to 9.7%, with the maximum potential recorded during the summertime.

Despite reducing emissions at the island level, CO_2eq releases increase due to the intensification of flexible gas-fired usage in the mainland in the Interconnection Scenario (Figure 5.59). The scheduled scenarios seem to keep emissions near the BAU case in S1, and a relative reduction is recorded over the max and min weeks. By 2040, there is a marginal reduction (0.2-1.1%) across some charging patterns in the maximum week, when solar power is abundant in the mainland to be exported to the islands. Under S2, during maximum and average load weeks, emissions are recording a growth up to 4% considering public charging. Over wintertime, with wind speeds being traditionally high, EV deployment seems to impact positively, leading to a 5.4% reduction. By 2040, lower emissions levels are evidenced across most scenarios. However, the vast number of EVs combined with fast chargers in public spaces leads to emissions increase equal to 5.5% in public charging. On the other hand, the V2G-restricted case, when combined with an aggressive S2 scenario, presents a 5.9% reduction.

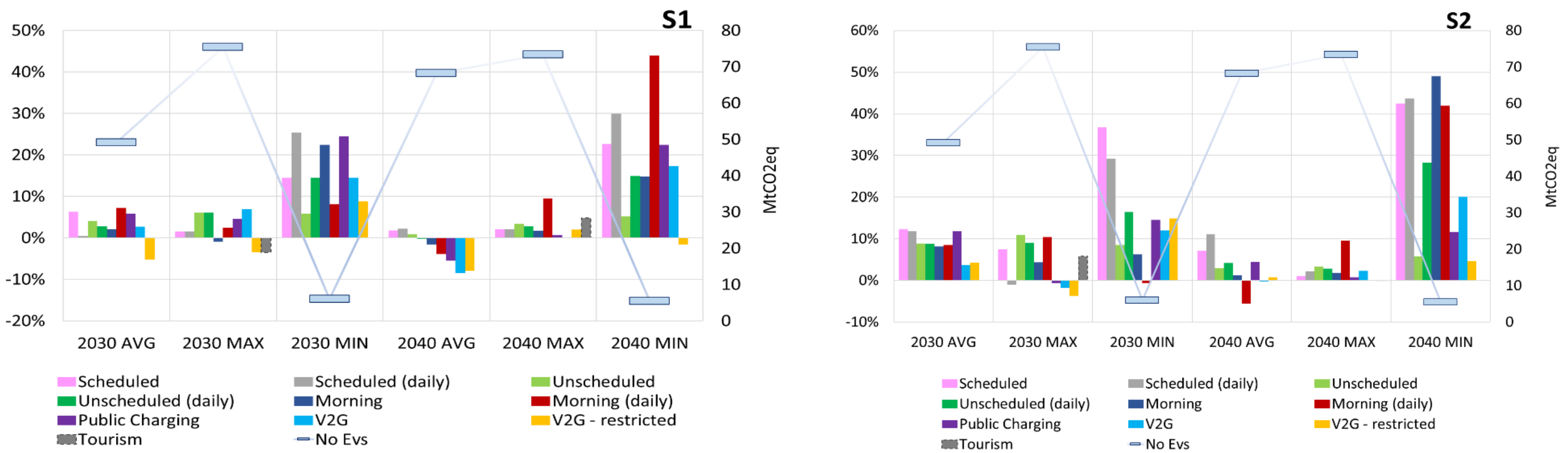


Figure 5.57: EV charging scenarios environmental impact (X-axis) vs No-EVs baseline (Y-axis) – Autonomous Batteries (AB.y.1.0)

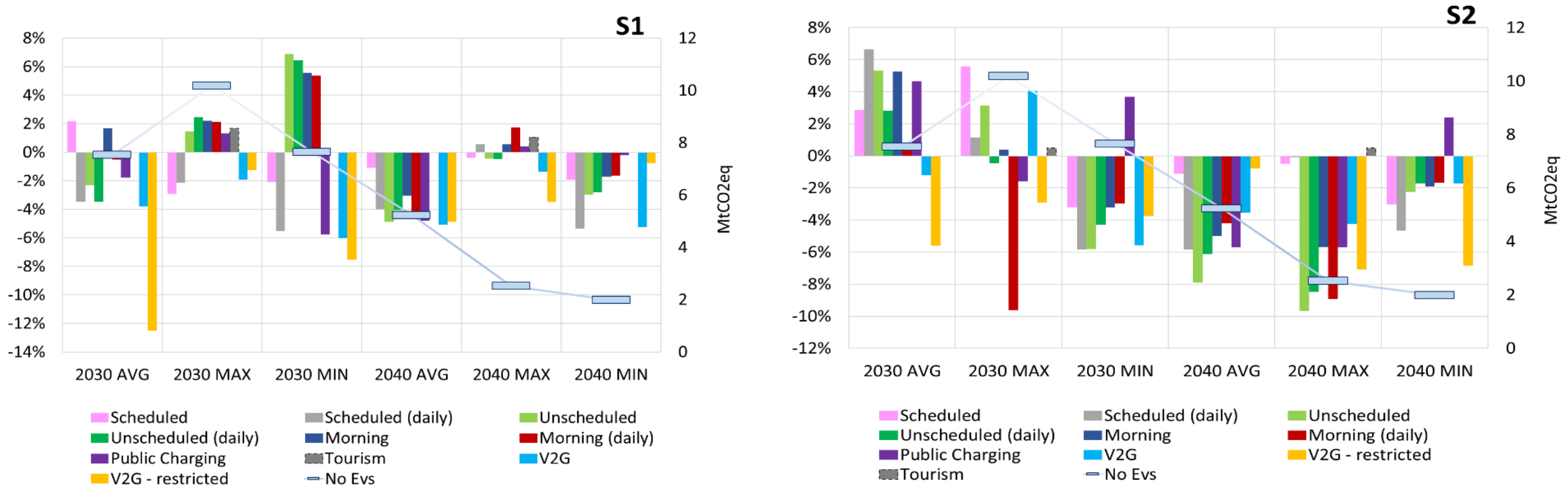


Figure 5.58: EV charging scenarios environmental impact (X-axis) vs No-EVs baseline (Y-axis) week – Interconnected (I.x.1.0.a), Islands region

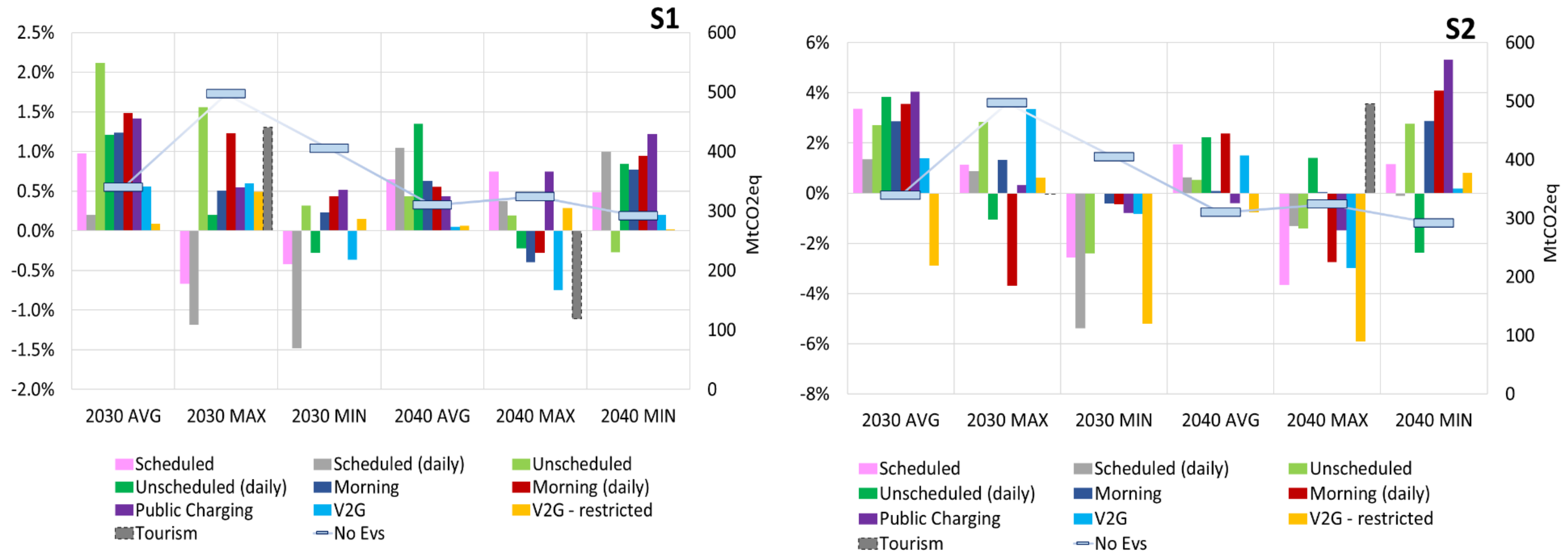


Figure 5.59: EV charging scenarios environmental impact (X-axis) vs No-EVs baseline (Y-axis) – Interconnected (I.x.1.0.a), System (national) level

5.4.2.2 *Emissions savings in the Transport Sector*

This analysis quantifies the comparison of emissions released per annum and per island from a new conventional ICEV versus an electric car, assuming a bidirectional charging strategy fully displayed in ANNEX III. In 2030, there is evidence that the transport sector's electrification under energy autonomy (AB.y.1.0) will reduce only marginally emissions by 590 tCO_2eq. Hypothesising a rapid growth of EVs, the impact is also limited to 3,400 tCO_2eq. By 2040, however, there is approximately a sixfold increase in the EVs driven, which forces more thermal generation to be dispatched while lifting emissions to 15,250 tCO_2eq in S1 and 42,500 tCO_2eq in S2. Despite reducing on average local emissions compared to the baseline non-EV scenario in the S1 case, the carbon intensity in the region is not low enough to compete with future cleaner ICEV. Particularly, islands such as Chios, Crete, Lemnos, Lesvos and Thera seem to have the most carbon-intensive energy mix, usually above 500 kg/tCO2eq.

In the Interconnected case, imports cover a considerable part of the demand, ranging between 5 and 55%. Consequently, emissions are reduced by 6,800 tCO_2eq under S1 and 25,400 tCO2eq under S2. This is attained due to a cleaner energy mix locally and nationally, with carbon intensities below 400 kg/tCO2eq and sometimes reaching 200 kg/tCO2eq. This proves that the carbon intensity threshold for a region is circa 460 kg/MWh, above which it is preferable to adopt a non-electric mobility option considering known assumptions regarding the new generation of ICEVs as explained in Section 4.7.2.1. In 2040, emissions reduction double scores to 12,500 tCO_2eq in S1 while under S2, 150,800 tCO_2eq emissions reduction is experienced, translating into almost 370 million t/year of oil not used, with multiple benefits for the environment.

6. Discussions and concluding remarks

6.1 Summary

The Greek islands experience a number of structural deficiencies related to their electricity system, which can be summarised under the Energy Trilemma Index (World Energy Council, 2019) adapted to the scope of this research project. While employing long-term investment planning in combination with short-term dispatch modelling via the PLEXOS energy systems model, this thesis investigates and answers the following research question:

Which is the optimal solution in the short and long-term for enhancing the effective implementation of secure, affordable and sustainable electricity on the Greek islands?

This is achieved by examining how major infrastructure reforms in submarine interconnections and storage in parallel with RES integration could: I) contribute to the future electricity security and supply, II) lead to the least-cost electricity mix, III) reduce emissions at the regional and national level IV) coupled with future demand scenarios, incorporate energy efficiency policies and finally V) deploy and integrate to the local system EVs. Policymakers could strategically use the main results in conjunction with the recommendations provided for designing the future Greek islands' electricity system, given the undergoing transition.

The first section of this chapter analyses the performance of the various scenarios against the ETI at the national (system) and the regional level while applying a normalisation method. The results demonstrate that the submarine interconnections, when coupled with BESS, usually demonstrate the optimum solution across the ETI dimensions. Exceptions remain certain islands such as Agios Efstratios, Milos, Serifos and Symi, which could continue their energy independence supported by large-scale BESS.

The importance of investing in new infrastructure and clean energy projects when combined with energy efficiency measures and bi-directional (V2G) charging is highlighted in a more extensive discussion around this research's key findings and recommendations in Section 6.3. The rest of this chapter underscores the thesis contribution to the research community and its novelty compared to other similar studies. Limitations regarding methods and data employed and suggestions for future research are provided, succeeded by the main concluding remarks.

6.2 Scenario assessment

The thesis research objectives focus on improving the current autonomous or partially interconnected island electricity systems under the adapted ETI principles. For achieving this, future policies alongside key technologies are examined to assess their impact on increasing local RES generation without compromising the techno-economic efficiency of the islands' system operation. A comparative ranking of the three parameters was provided resembling the ETI: the share of unserved demand (%), for the security of supply, the power generation costs to reflect economic affordability and finally, the emissions reflected in CO2eq to measure the environmental sustainability.

A normalisation approach was applied to align the three ETI indicators according to Eq. 6.1, considering the minimum and maximum values of parameters (X) in each of the three ETI categories. The scale ranges between 0 and 1, representing the lowest and highest performance, respectively.

$$X' = \frac{X - X_{min}}{X_{max} - X_{min}}$$

Eq. 6.1

6.2.1 System level

The modelling outcomes at the system (national) level illustrated in Figure 6.1 highlight that submarine transmission extensions are necessary for optimizing island electrical system operation. Exposing the contradictory nature of the ETI parameters under particular contexts, also stressed by Dani Rodrik (2007), optimal scoring 1/1 across all dimensions is not achieved under one single scenario. However, the Interconnection-Batteries case records the highest scores ranging between 0.86 for Economic Affordability, 1 for Environmental Sustainability and 1 for Energy Security.

Beyond the evident flexibility benefits provided, interconnections support demand and supply balance in the mainland while eliminating power interruptions which are often experienced during the summer months of June or July due to increased cooling demand. In August, the demand peaks are displaced on islands where the sharpest security of supply risk is recorded. Therefore, load shedding is reduced by 48% to 156 GWh annually compared to 300 GWh under the Autonomous Scenario (A.y.1.0.a), which further escalated to 327 GWh if generation restrictions are imposed under the Autonomous-Batteries (AB.x.1.0.a) case. Considering multiregional transmission support combined with storage, the IB.x.1.0.a scenario scores one as unserved demand is eliminated.

Regarding economic affordability, the results also highlight that the IB.x.1.0.a scenario generates the lowest system costs at 66.4 €/MWh benefiting from massive RES deployment across the country, enabling the minimisation of CCGT units on the mainland. The I.x.1.0.a option comes second with 68.4 €/MWh, while the AB.x.1.0.a records 70.8 €/MWh due to the partial continuation of oil-fired generation on islands in parallel with the lack of means to transmit power from the islands to the mainland. Finally, the A.y.1.0.a assumes 73.6 €/MWh as oil and lignite-fired generation are sustained, increasing further due to carbon prices. The results highlight that if RES development occurs in the Autonomous context, the benefits are limited at the regional level, while interconnections coupled with storage technologies make electricity more affordable at the national level.

Considering environmental sustainability, the A.y.1.0.a scenario envisaging relaxed policies and commitments records significantly higher emissions with an average of 20.6 MtCO2eq per year over the projection horizon. If autonomy continues while employing an ambitious storage deployment plan (AB.x.1.0.a), emissions are reduced to 5.8 $MtCO_2eq$ per year. This is also a combination of more ambitious policies imposing LS fuels, which drive down the utilisation of conventional fuels. On the contrary, the I.x.1.0.a as well as the IB.x.1.0.a scenarios successfully reduce average emissions to 13 and 12 MtCO2eq/year, respectively showcasing the national impact of such a trajectory. Scores range between 0.85 and 1 ETI as they exploit the regional wind and solar potential while also being driven by ambitious policies.

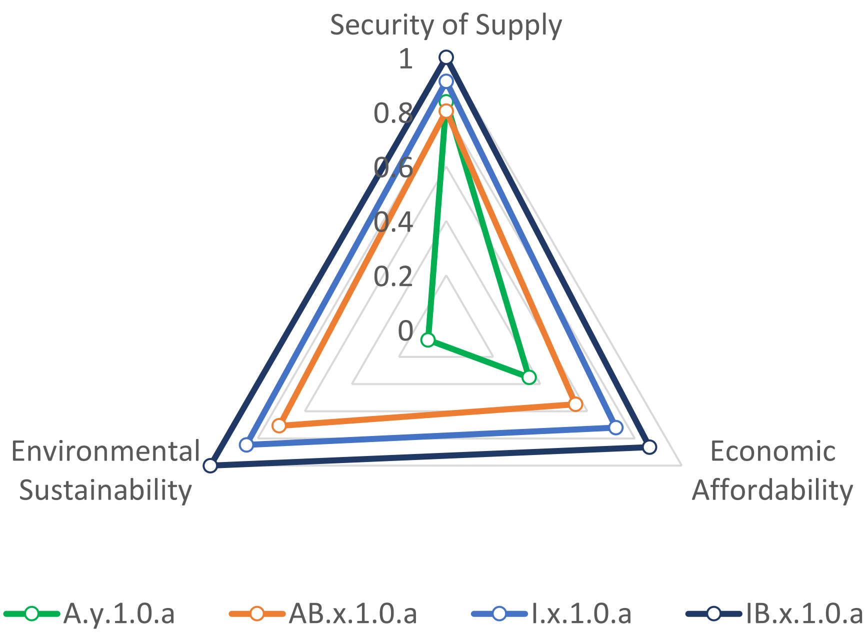


Figure 6.1: ETI at the system (national) level - Principal scenarios

6.2.1.1 *Sensitivity Analysis*

The sensitivity analysis exploring the impact of various techno-economic and policy trajectories is depicted in Figure 6.2. In the **Autonomous (A) Pathway,** it is evident that the scenarios imposing power generation restrictions on islands (A.x.) will record significant unserved demand with scores ranging between 0 and 0.6 translated into an average loss value of 1,298 GWh per year, i.e., 1.6% of the total demand. With more than 97% of the incidents experienced in the islands' region, an average value of 17% unserved demand is recorded. Despite the benefits of applying high-efficiency policies in A.x.1.2, unserved demand levels remain high. Such scenarios present low performance below 0.5 on sustainability and affordability and, therefore could not be considered feasible.

Continuing with the BAU (A.y) scenarios without restrictions, improved performance in the security of supply criterion is evidenced with scores ranging between 0.71 and 0.89 and an average load loss equal to 300 GWh/year. This is translated into 0.38% of unserved demand at the national level and 3% at the regional level. The quantifiable impact of energy efficiency measures is represented via High_Eff ISLA_EGI scenario in A.y.1.2.a or b, demonstrate 195 GWh/year of unserved loads compared to the Low_Eff case (A.y.1.1), recording 350 GWh/year. It is worth mentioning that energy efficiency policies in the services and residential sectors demonstrate increased savings, especially during the evening hours over the summer months when the highest peak is recorded, benefiting from reduced water heating, cooking and lighting consumption.

Regarding CO_2eq, the lowest performance among all scenarios is recorded in the A.y pathway, with an average value of 0.07, translated into emissions of 20.6 $MtCO_2$eq/year at the system and 2.75 $MtCO_2$eq/year at the regional level. The A.y.1.2.a/A.y.1.2.b scenarios with ambitious energy efficiency measures are recording 3% reduction compared to A.y.1.0.a. The Autonomous scenario considering the minimum renewable energy growth (A.y.2.0) would increase further cumulative emissions to 3.4 $MtCO_2$eq/year, underlining the importance of taking advantage of the clean energy developments on the Greek islands. The A.y.2.1 considering higher oil fuel prices via the 'Current Policies' scenario would only record a 1% increase. This is due to the use of low Sulphur diesel, an expensive fuel, by the island of Crete already under A.y.1.0.a. Despite the increase in fuel prices which could contain their use, the parallel demand growth results in this marginal emissions increase.

On the other hand, generation costs are considerably affected, increasing to 78.5 €/MWh in A.y.2.1 with zero scores, from 73.6 €/MWh in A.y.1.0.a. Contrariwise, High_Eff demand combined with increased CO_2 costs and fuel prices (A.y.1.2.b) would drop costs to 67 €/MWh, which meets the generation cost levels of the Interconnection Scenarios, recording the highest score in the pathway at 0.82. Offshore development in parallel with the Cycladic islands interconnection under A.y.1.0.b could further drop costs to 72.5 €/MWh. The replacement of Crete's oil-fired generation with NG (A.y.1.0.e) may also decrease costs to 69 €/MWh[49], in parallel with a cumulative emissions reduction up to 4 $MtCO_2$eq, reflecting the weight factor of Crete's electricity system.

[49] Considering fuel price forecasts as indicated in WEO 2018.

Considering the security of supply ETI indicator, the massive deployment of BESS in parallel with renewable energy under the **Autonomous Batteries (AB) Pathway** scores between 0.72 and 1. In AB.x.1.1.b, the Low_Eff, ISLA_EGI scenario supposes demand growth trends in the residential and services sectors while the BAU 'Current Policies' fuel price scenario is applied, leading to an average of 525 GWh (0.65%) of annual power interruptions. This amount could be minimised to 393 GWh/year if an ultra-ambitious scenario (AB.x.1.2.c) is in place, assuming immediate actions to improve the efficiency of the current building stock, in parallel with increased fuel and carbon costs which drive down conventional fuels demand. Load shedding could be further reduced to 160 GWh/year if natural gas was introduced to Crete's power system (AB.x.1.0.c) with a tradeoff in emissions increase by 2.5% compared to the AB.x.1.0.a. Such results highlight that the NIIs are the weakest link in terms of power shortage incidents, while more than 60% of the unserved demand recorded in the region takes place on Crete. The alternative of continuing the operation of existing thermal units while enhancing the system with BESS in AB.y.1.0. shows resilience in the region, with marginal environmental sustainability and affordability deterioration. Such a scenario shows that oil-fired generators are used to cover peaks by lifting generation restrictions in this context. At the same time, higher BESS capacity factors are evidenced, benefiting from the additional generation provided.

Overall, an average reduction of emissions by 9% is recorded under the AB pathway, with scores ranging between 0.46 and 0.56. Such a reduction could be further enhanced to 12% (AB.x.1.2.c) if a set of ambitious targets and policies is combined with the analogous investment appetite for clean energy projects. The environmental and technical performance improvement is aligned with a relative power generation cost reduction of 1.3 €/MWh at a system level and 47 €/MWh at the regional level. The AB.x.1.2.b scenario lowers average generation costs to 66.4 €/MWh. Nonetheless, this is the maximum reduction that can be recorded, benefiting mainly from robust decarbonisation plans for the islands without the synergies offered by interconnections.

On the contrary, if HV submarine transmission extensions take place under the **Interconnection (I) Pathway,** average costs are reduced by 3.4 €/MWh, (i.e.

70.2 €/MWh) compared to the Autonomous Storyline. This is attributed to conventional generation in the mainland being replaced by renewable energy produced in the islands' region, recording the maximum efficiencies. The least cost-efficient scenario is I.x.2.1., with 73 €/MWh due to low-RES deployment combined with a Low_Eff ISLA_EGI scenario. The cheapest interconnection option assumes NG on the island of Crete (I.x.1.0.f) with 65 €/MWh as it successfully transforms the island network in a short period with a relatively high upfront investment cost, however, with a short amortization period.

In the interconnected context, the average unserved demand of 160 GWh per year (0.2%) is recorded in the Greek electricity system and approximately 2% in the islands region. The direct transmission line between Kos and the Greek mainland (I.x.1.0.b), instead of the route interconnecting the Dodecanese islands via Crete, would result in a 46.7 GWh/year increase in power shortages combined with a 60 ktCO2eq annual emissions growth as a result of marginally higher NG generation compared to I.x.1.0.a. The High_Eff, ISLA_EGI scenario (I.x.1.2.a) succeeds in reducing unserved demand by almost 50% compared to I.x.1.0.a with positive impacts in emissions reduction by 2.5% and the highest score of 0.94. Such a scenario serves as an alternative to large-scale utility energy storage in certain islands such as Chios, Ikaria, Lemnos, Mykonos and Skyros. High energy efficiency measures also attain 16% emissions decrease in the islands' region, while costs are configured close to 68 €/MWh. An Interconnection scenario without thermal units' restrictions (I.y.1.0.a) would succeed in eliminating unserved demand, recording only a minor increase in emissions levels, which shows that the system will become self-regulated under conditions where renewables become the cheapest option.

It is worth mentioning that under I.x.1.0.f, if NG is introduced already in the early 2020s, a certain thermal generation capacity is displaced from the mainland to Crete. When combined with RES and interconnections, such flexible units reinforce the regional network of Crete and the Dodecanese islands while considerably reducing local costs. Emissions levels are also reduced to less than 12.6 MtCO2eq/year at the system and 600 ktCO2eq/year at the island level. Overall, in the interconnected context, NG is not competing with renewables but with oil, eliminating its use while NG infrastructure investments are amortised in 5 to 6 years. Nonetheless, despite its optimum ETI performance with minimum power shortage below 0.1%, it imposes Greece to prioritise natural gas over clean energy sources in the long term, which does not align with the EU and national goal to become a natural climate economy by 2050.

BESS could offer similar flexibilities with NG under the **Interconnection-Batteries (IB) Pathway**. Despite higher upfront capital costs, such a scenario would pay off long-term by securing the system's reliability and effective demand and supply management with zero unserved demand. The IB.x.1.0.a scenario is also triggering a high cumulative emissions reduction of 41% compared to A.y.1.0.a as renewables are scaling up. Similarly, costs are reduced to 67.5 €/MWh. The combination of interconnectors and storage at the regional level enhances the system's reliability while the average costs remain the same between I and IB pathways. Emissions are reduced to 800 ktCO_2eq/year at the island level compared to 3.2 MtCO_2eq in the BAU scenario. The significant CO_2 decline, typical in the I and IB pathways, originates from the considerable reduction of lignite-fired generation, the retirement of old inefficient generators in the mainland, and the high penetration of renewables. The further CO_2 abatement in the islands' region is explained by the extra boost of wind energy and the complete retirement of oil power stations by 2040.

Finally, the IB.x.1.0.b case prioritises cost-efficiency above all other indicators presenting the lowest total and generation costs at 64.5 €/MWh, scoring 1. This scenario invests heavily in centralised NG stations on the mainland, benefiting from economies of scale; therefore, it could only be assessed nationally. Only following 2027, when renewable energy costs have dropped significantly, the system invests in wind and solar in the islands region. Overall, despite supporting BESS, generation levels increase by 50% compared to the IB.x.1.0.a. On the other hand, the highest emission levels are recorded among all Interconnected Scenarios, averaging 19.2 MtCO_2eq/year, which falls far behind the national and European standards. Such a scenario proves the competitive nature of the ETI parameters under certain conditions, as the highest performance criterion might sacrifice the equivalent of the rest.

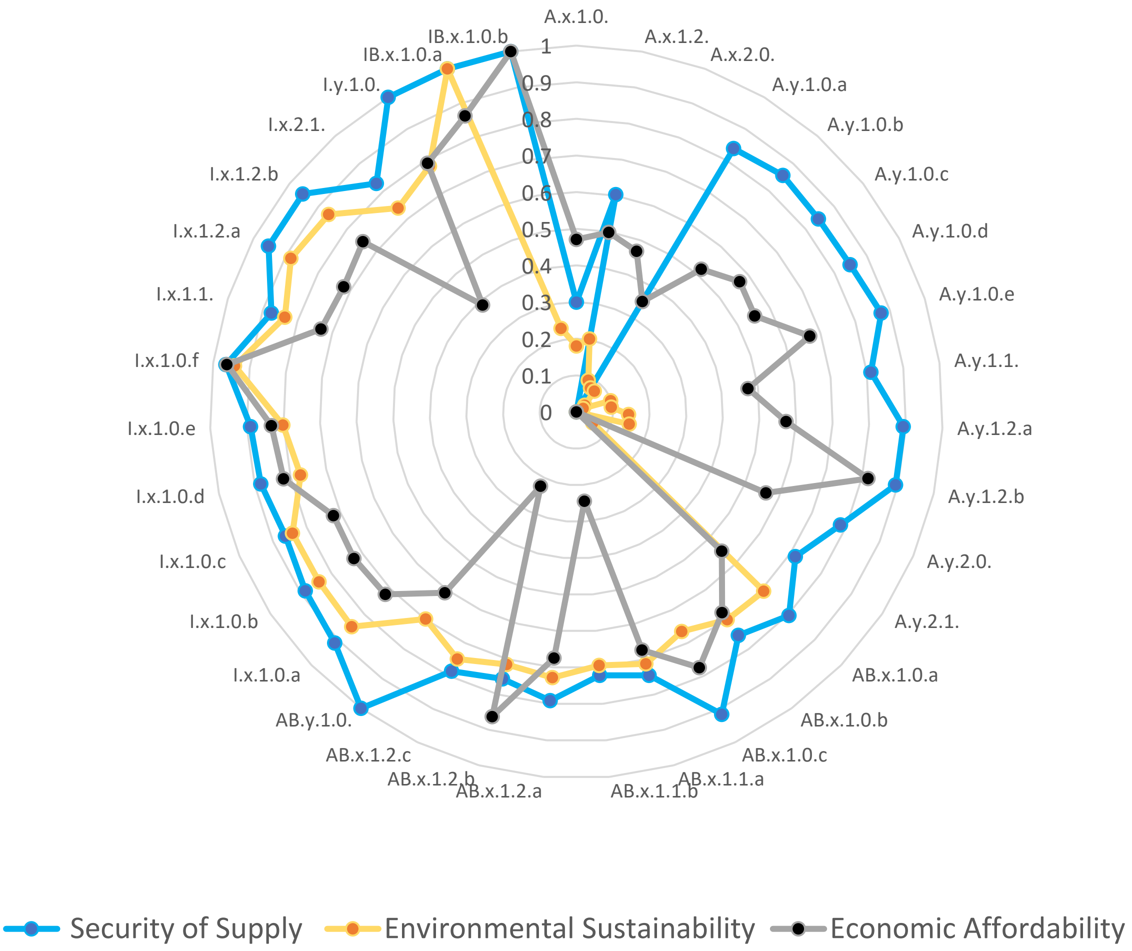


Figure 6.2: ETI performance at the system (national) level – Sensitivity analysis

6.2.2 Regional level

6.2.2.1 *Northern Aegean Sea Islands*

Agios Efstratios is the smallest electrical system examined in Northern Aegean Sea, with loads < 1 MW. Nonetheless, this small island may become the focal point for a large-scale offshore wind farm with a total capacity 445 MW as it possesses high wind potential combined with shallow waters. Agios Efstratios performs optimally if it remains non-interconnected, supported by BESS (Figure 6.3). The final system configuration consists of a W/T of 1 MW and two solar stations of 100 kW each, combined with a 3 MW/24 MWh battery system with a utilisation factor of 22%, which could further support the ‘Agios Efstratios – Green Island’ initiative. Batteries successfully balance the demand and supply on the island while eliminating thermal generation and eventually transforming the island into a 100% RES system. Therefore, the interconnection of Lemnos and Lesvos with Agios Efstratios is judged unnecessary, while the two islands (i.e., Lemnos and Lesvos) could become directly interconnected.

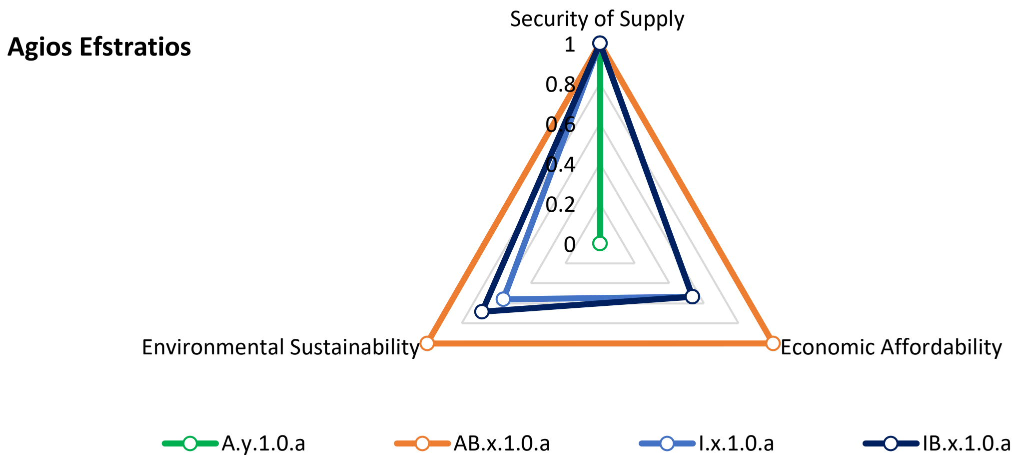


Figure 6.3: ETI performance - Agios Efstratios

Chios is a middle-sized island with active agriculture, farming and processing industrial activities. Therefore, its hourly and monthly load profile follow a smoother pattern than other islands depending solely on tourism. Chios as well as the rest of the Northern Aegean Sea islands have a high wind potential and adequate size to develop RES projects while already operating 15 MW of wind and solar systems. According to Figure 6.4, the best ranking solution is the interconnection mainly because of improved demand and supply balancing performance. Nonetheless, the AB.x.1.0.a scenario records the lowest costs at 77 €/MWh while emissions decline by 26% compared to I.x.1.0.a with 101 €/MWh, as RES, replace the total thermal generation fleet before 2030. In the Interconnection Scenarios, islands will be partially dependable on local thermal generation capacity until 2038, while RES deployment is fully aligned with submerging submarine cables. BESS in the Interconnected context is judged unnecessary due to limited operation. Overall, 326 MW of wind and 17 MW of solar PVs will be developed combined with a hydro pump system of 38 MW.

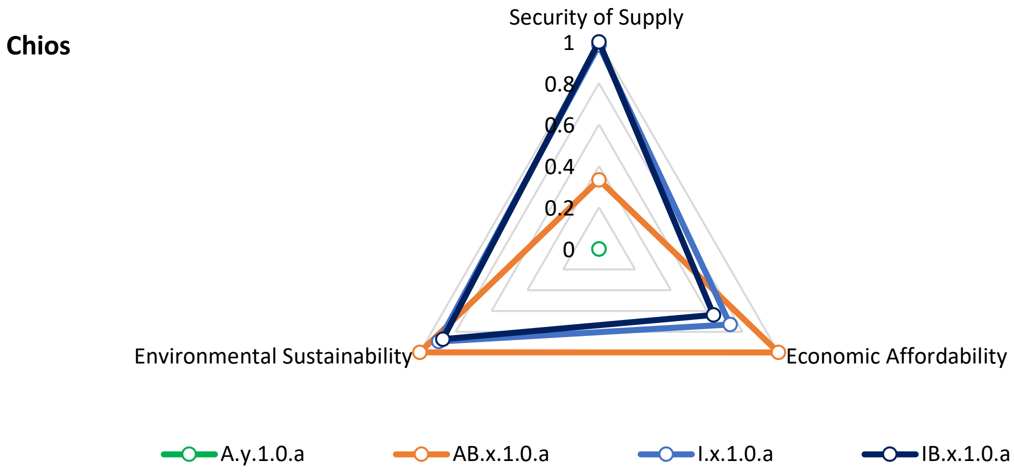


Figure 6.4: ETI performance – Chios

Ikaria presents a unique system as it already operates a WPHS with a relatively higher share of renewables, reaching 34%. However, the modelling results depicted in Figure 6.5 show that the continuation or enhancement with BESS of the current AES will require the continuance of oil-fired units' operation. Particularly the local generation costs remain high at 168 €/MWh. On the other hand, the Interconnection scenario I.x.1.0.a reduces costs to 95 €/MWh, and if BESS are employed, they drop to 90 €/MWh. Regarding carbon emissions, the IB.x.1.0.a succeeds in reducing them by 65% compared to the BAU (A.y.1.0.a). The final generation mix under such a scenario suggests the installation of 15.5 MW/108 MWh of BESS alongside 43 MW of wind and 5 MW of solar on the island.

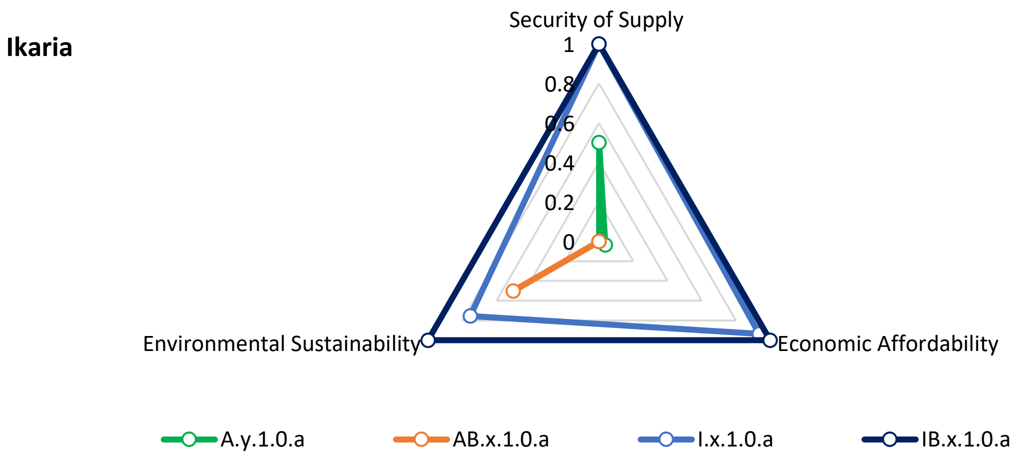


Figure 6.5: ETI performance - Ikaria

Lemnos is a medium-sized island that has attracted investors' interest regarding onshore and offshore wind. Currently, 3 MW of wind and 1.9 MW of PV have been installed on the island. Figure 6.6 shows that the optimal solution is the IB.x.1.0.a despite the relatively higher generation costs (116 €/MWh vs. 104 €/MWh in AB.x.1.0.a). The Interconnection-Batteries case records the lowest emission levels at 340 ktCO_2eq while eliminating load shedding, whereas the same scenario without the employment of BESS would result in emissions augmented by 35%. The ultimate scenario proposes the installation of 13 MW/91 MWh of BESS, 205 MW of on-shore wind and 498.15 MW of off-shore, which may facilitate the development of the necessary infrastructure to host the submarine interconnection of the Northern Aegean Sea islands with the northern mainland. Finally, 12 MW of solar PV will be installed to complement the local electricity mix.

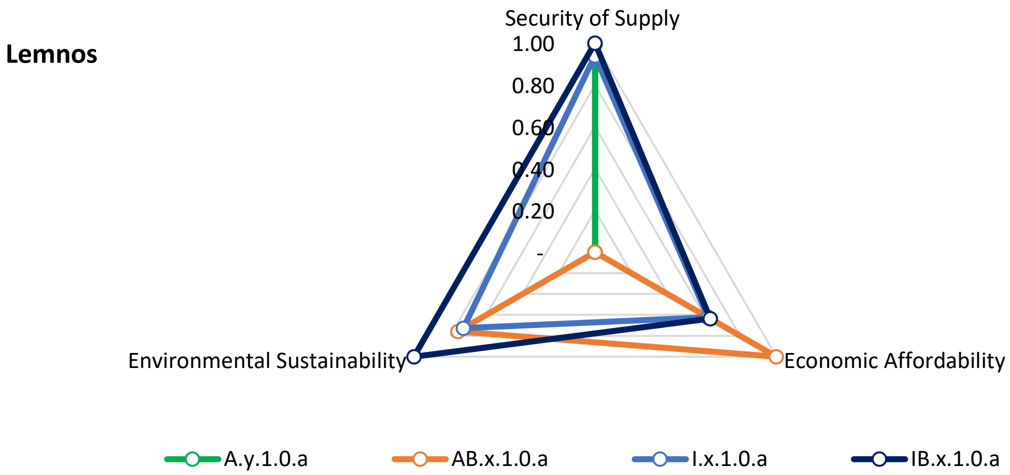


Figure 6.6: ETI performance - Lemnos

The island of Lesvos is the third-largest in size and population and the fourth in terms of annual demand. Lesvos currently hosts 14 MW of wind and almost 9 MW of solar PV. Similar to the rest of the Northern Aegean Sea islands, it welcomes smaller volumes of tourists; therefore, it presents a smoother seasonal demand profile. In addition, the island hosts a large number of refugees resulting in relatively increased winter loads. The island deploys 300 MW/1500 MWh of BESS together with 259 MW of wind, 9.6 MW of solar and 8 MW of geothermal capacity. The Autonomous pathways score low either in the 'security of supply' indicator concerning AB.x.1.0.a or in environmental sustainability and economic affordability in the A.y.1.0.a context (Figure 6.7). The IB.x.1.0.a scenario is considered the optimum, with average generation costs below 87 €/MWh and a reduction of 70% in CO_2eq emissions compared to the BAU case.

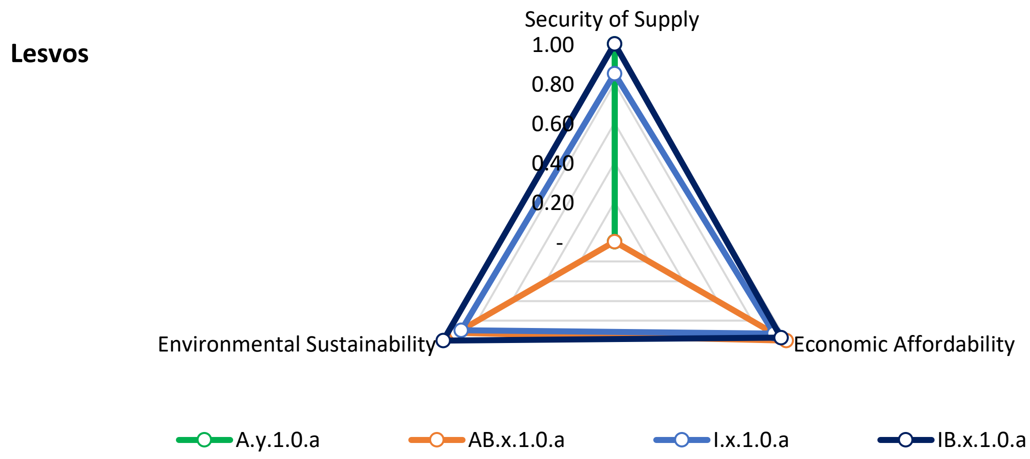


Figure 6.7: ETI performance - Lesvos

Samos is a medium-sized electrical system including the small islands of Fournoi and Thymaina, having already a RES share of 35%, recording one of the best ratios in the non-interconnected region. According to Figure 6.8, the AB.x.1.0.a case is scoring low in terms of security of supply, recording on average 63 GWh of unserved power every year, whereas the BAU (A.y.1.0.a) case is experiencing the highest emissions levels and generation costs. The interconnection options score high in terms of sustainability and affordability. Nevertheless, only the IB.x.1.0.a scenario succeeds in securing the smooth power supply in the region after 2035. Such a scenario will allow the deployment of a battery system of 114 MW/684 MWh, 125 MW of wind and 25 MW of solar.

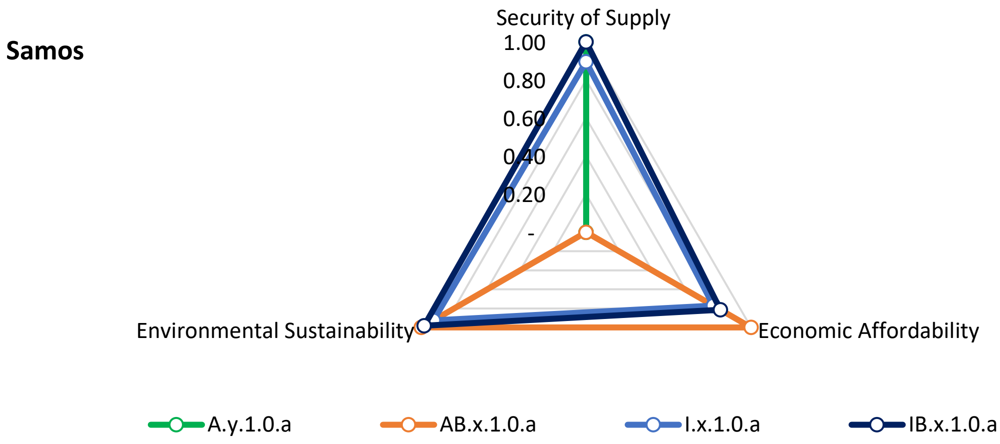


Figure 6.8: ETI performance - Samos

Skyros belongs to the Sporades region, where the remaining islands have already been interconnected. Due to the lack of demand data for Skyros, it has been grouped for the sake of this analysis with the Northern Aegean Sea region considering correlation in historical data. According to Figure 6.9, both Interconnection scenarios present equal scores, with the I.x.1.0.a case experiencing minor power shortage incidents until 2030 mainly related to the submarine cable installation. Both scenarios succeed in reducing local generation costs to 69 €/MWh. However emissions are sustained at 3.4 $ktCO_2eq$/year compared to the 0.25 $ktCO_2eq$/year in AB.x.1.0.a as the island becomes interconnected only by 2030, whereas in the AB case, the gradual replacement of thermal stations with RES commences from 2020. Under such a scenario, unserved demand exceeds 23% of the annual load, which makes it unsuitable for the island of Skyros mainly because of the limited expansion of renewables, especially solar. On the other hand, 7.5 MW of solar and 335 MW of wind are foreseen in the interconnection scenarios. Such a large-scale flagship project could be converted to a floating offshore installation to avoid high visual impact, providing clean power to the NGS under high-efficiency levels with net capacity factors exceeding 38%.

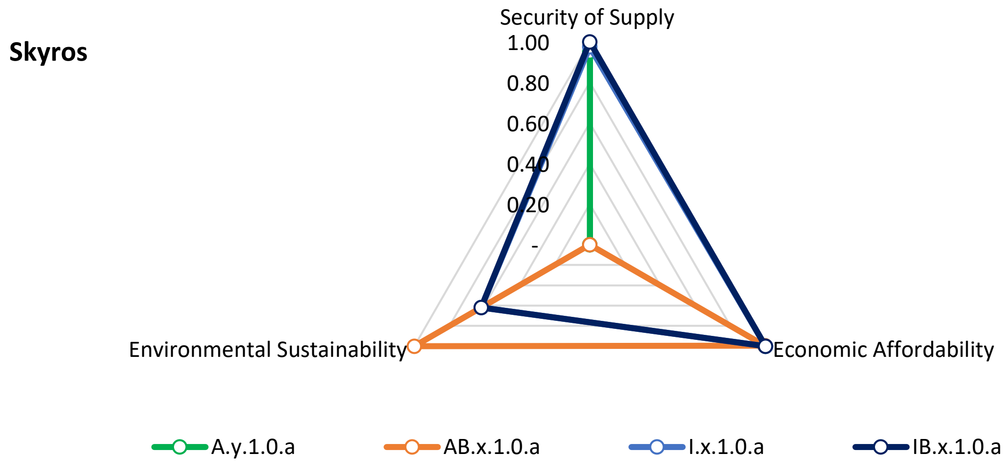


Figure 6.9: ETI performance - Skyros

6.2.2.2 *Dodecanese Islands*

The small island of Kasos is connected since 1984 with MV submarine cables with Karpathos, which operates the local thermal power plant. This electrical system shows that it may not remain independent as the Autonomous-Batteries scenario experiences multiple outages on an annual basis. Therefore, as Kasos-Karpathos system is located in the critical interconnection path of Crete with the Dodecanese region, its interconnection with the rest of the islands becomes essential. The IB.x.1.0.a guarantees the continuous power supply with flexibility support while recording the lowest emissions decline up to 66% compared to A.y.1.0.a and costs below 102 €/MWh (Figure 6.10). The local wind is increased to 38 MW and solar to 4.5 MW while 34 MW/136 MWh BESS is built, with a gradual deterioration as replaced by the dispatchable geothermal station on the island of Nisyros. To avoid unnecessary investment costs in storage, the I.x.0.1.a could also be a viable solution following 2030 if more dispatchable stations, including geothermal and bioenergy, are commissioned or by allocating higher shares of ancillary services provision of the existing operational stations. In that case, I.x.1.0.a could be qualified to propose 30.45 MW of wind farms and 7 MW of solar.

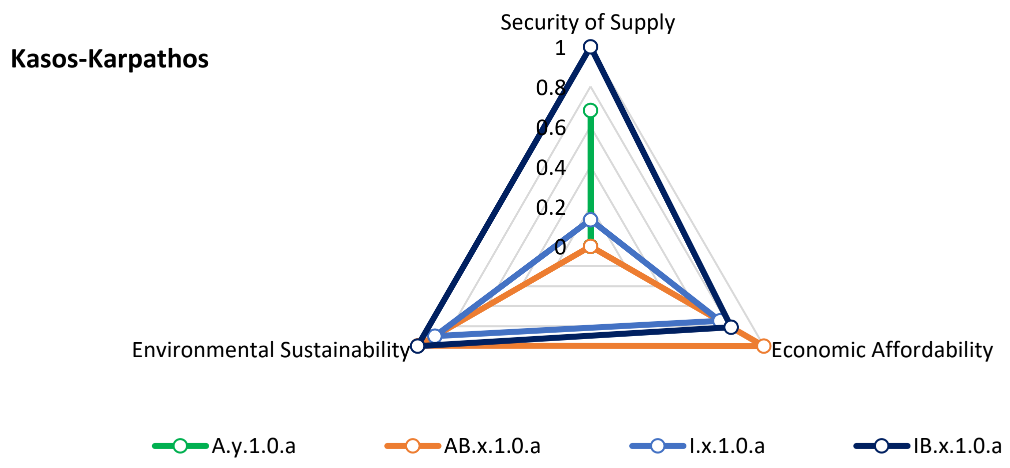


Figure 6.10: ETI performance - Kasos-Karpathos

Kos-Kalymnos medium-sized system beyond the islands of Kos and Kalymnos comprises several other smaller islands such as Leipsi, Telos, Telendos, Gyali, Pserimos, Leros and Nisyros. Particularly, the island of Telos exemplifies a best practice while being the first island in Greece to become energy independent with the use of solar and BESS. The results illustrated in Figure 6.11 show that interconnections demonstrate the optimum option for securing a reliable and clean electricity system in this region. While A.y.1.0.a, AB.x1.0.a and I.x.1.0.A scenario records power shortages at 8-10%, mainly experienced on Kos system, the IB.x.1.0.a succeeds in balancing demand and supply effectively with a battery located on the island of Kalymnos. Under such a scenario, a combination of 38 MW/380 MWh of BESS, 247 MW wind, 28.4 MW of solar, and 40 MW of dispatchable geothermal capacity located on the small island of Nisyros will allow the optimal operation of the interconnected system.

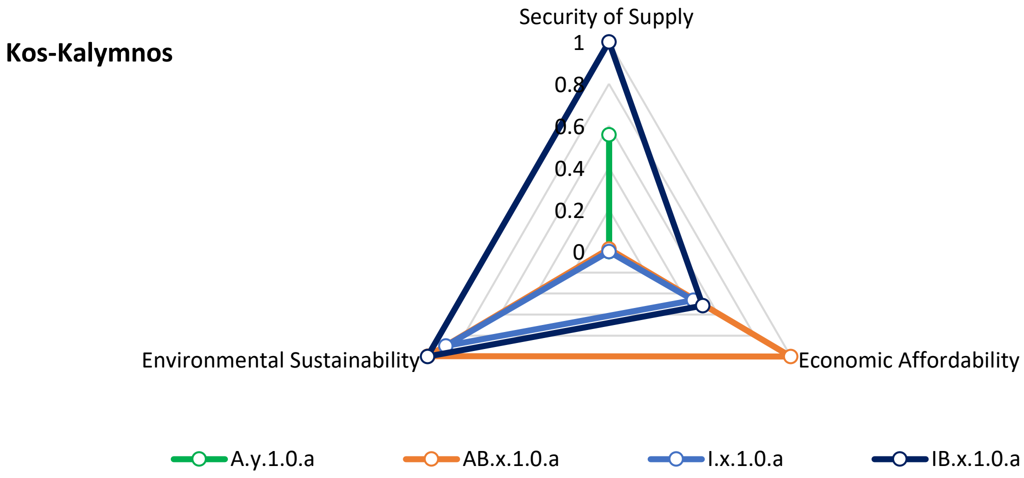


Figure 6.11: ETI performance - Kos-Kalymnos

The results for the small electrical system of Patmos show an overlap between I.x.1.0.a and IB.x.1.0.a according to Figure 6.12. Therefore, the most favourable solution for the electrical system of Patmos, with average costs of 131 €/MWh and reduced LCOE, is the interconnection without the employment of BESS on the island, despite its intensive use will not contribute noticeably to the system's techno-economic performance. Alternatively, if the system remained autonomous while relying on BESS, it would record severe power shortages up to 20% due to summer peaks. Therefore, the Interconnection scenario suggests that Patmos mainly relies on electricity imports to install 0.5 MW of Solar PV.

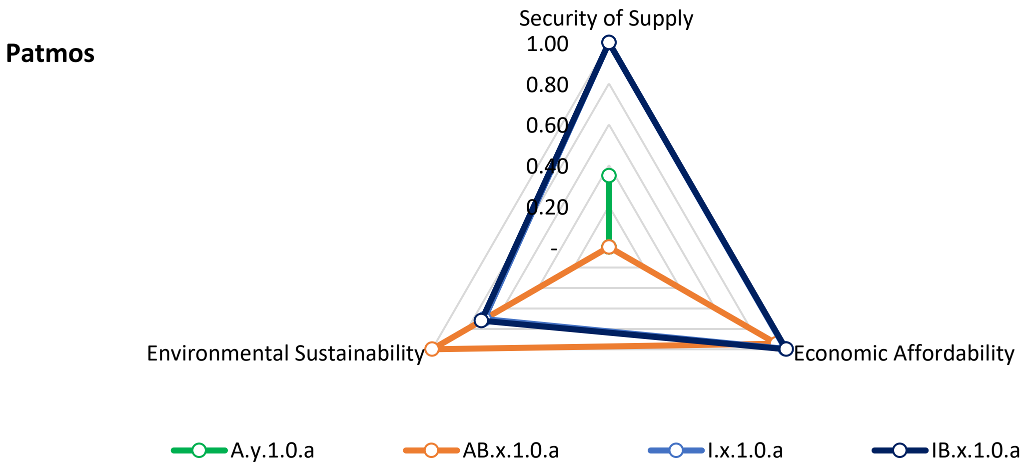


Figure 6.12: ETI performance - Patmos

The island of Rhodes, connected with the small island of Chalki, comprises the second-largest electrical system in the non-interconnected region and will serve as a key power supplier to the rest of the Dodecanese region once the interconnection is realised. The modelling results in Figure 6.13 show that there is no optimal scenario as the Autonomous-Batteries case, which records by far the lowest generation costs of 60 €/MWh and emissions close to zero. However, they will not cover extreme summer evening peaks, recording short but frequent periods of unserved demand. Such a scenario will deploy 417 MW/2,512 MWh of BESS, 644 MW of wind and 28 MW of solar, which is considered the largest amount of RES that could be deployed on the island of Rhodes. The second alternative is the Interconnection-Batteries scenario which generates higher costs of 103 €/MWh while maintaining some of the existing thermal stations on the island with zero power shortages. Herein, emissions drop by 66% compared to the BAU A.y.1.0.a. The IB.x.1.0.a proposes the installation of 358 MW/2,150 MWh of BESS alongside 350 MW of wind, 46 MW of solar PV, 33 MW of solar thermal and a 24 MW hydro pump unit. The main difference between the two scenarios is the timing as renewable capacity is installed as AB.x.1.0.a replaces oil-fired installation already from 2020 while in IB.x.1.0.a, it takes off following 2030 once the cable is submerged.

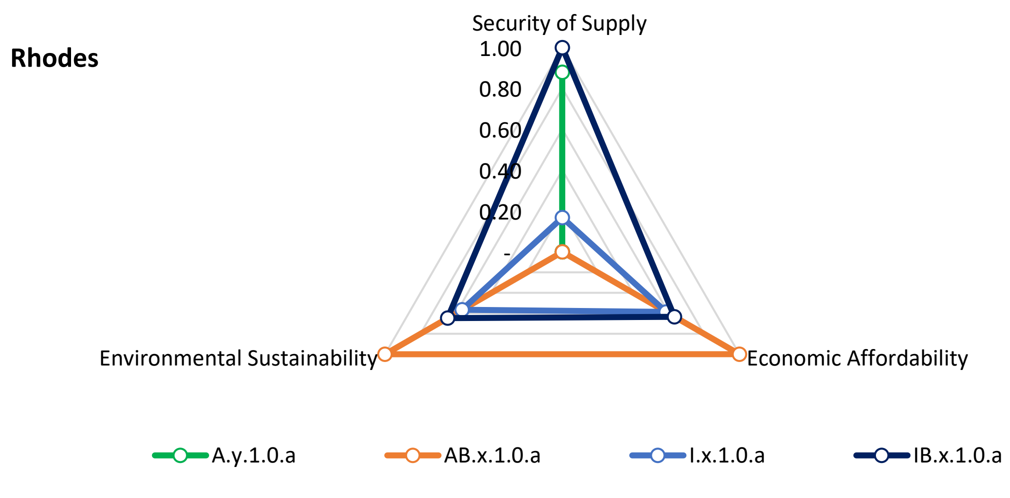


Figure 6.13: ETI performance - Rhodes

Symi is a small autonomous island system near Rhodes' proximity, which currently operates only 190 kW of solar PV. The island has been scheduled to become interconnected by 2029, whereas if BESS are deployed earlier, there will be multiple benefits, mainly in reducing emissions. The AB.x.1.0.a scenario scores 1 across all dimensions, according to Figure 6.14, as it allows the rapid acceleration of renewables. This scenario proposes the installation of 12.3 MW of wind and 0.5 MW of solar alongside a 10 MW/100 MWh BESS. Eventually, the I.x.1.0.a and IB.x.1.0.a scenarios will allow the deployment of similar renewable capacity, considering the space limitations of such small islands. All scenarios except the BAU (A.y.1.0.a) could facilitate a smooth transition for the island of Symi with the I.x.1.0.a presenting lower LCOE benefiting from the capacity reserve sharing mechanism and power flows exchange.

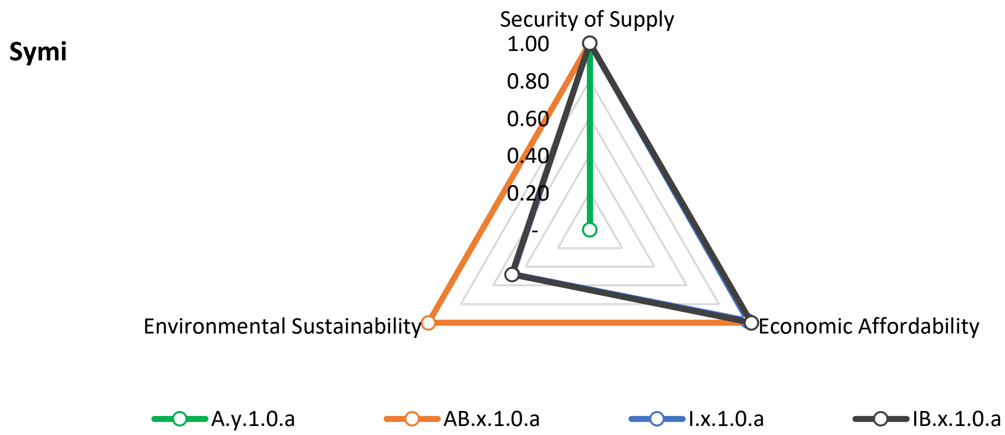


Figure 6.14: ETI performance - Symi

6.2.2.3 *Cycladic Islands*

Milos is a medium-sized electrical system located in the western part of the Cycladic islands. Milos processes an active geothermal field that has not been exploited yet, due to technical flaws of previous attempts. The island currently hosts 2.65 MW wind and 0.6 MW solar and has been scheduled to become interconnected in 2023 alongside the remaining Western Cycladic islands. The results prove that Milos could continue its autonomous operation while investing in BESS and benefiting from the local high enthalpy geothermal field, which could drop local generation costs by 62%, i.e., 69 €/MWh, compared to the Autonomous case. Furthermore, emissions are reduced by 65 % if large-scale hybrid systems are deployed (Figure 6.15). The final generation mix under the AB.x.1.0.a case, proposes installing a 23 MW/92 MWh BESS alongside 30 MW wind, 0.6 MW solar, and 2 MW geothermal with the potential to be expanded. Alternatively, the Interconnection-Batteries scenario (IB.x.1.0.a) records zero unserved demand levels, reducing costs by 32% and emissions by 70%. That scenario proposes only 1 MW solar and 2 MW of wind while being mainly dependable on imports from the mainland and supported by the BESS located on Serifos island. This could be an alternative if large-scale wind farms should be avoided on an island with particular natural beauty and a large protected NATURA 2000 area.

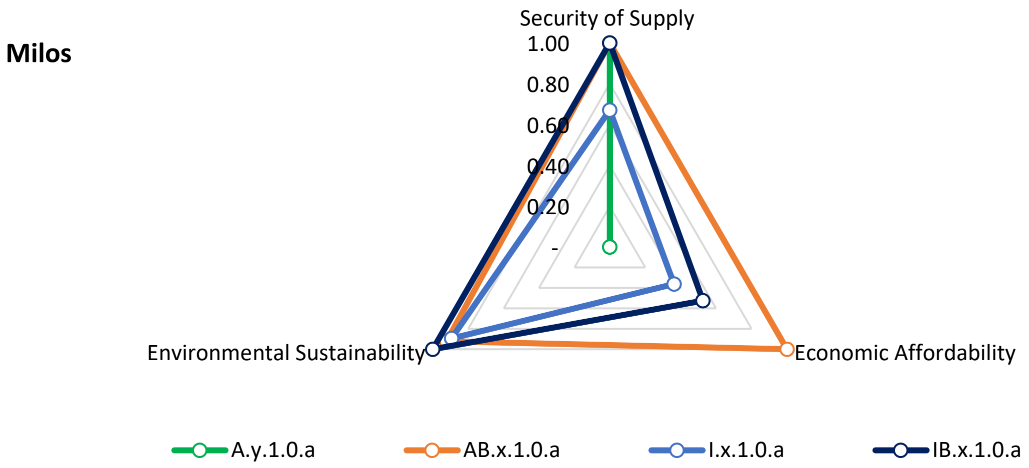


Figure 6.15: ETI performance - Milos

Mykonos island is highly popular, recording the largest number of tourists following Crete, Rhodes and Kos. Therefore, disparities arise during the year, with steep peaks over the summer months. Beyond a thermal station of 67 MW, which is kept mainly as a reserve following the island’s interconnection in 2020, a wind farm of 1.2 MW and a few small solar PV parks with a total capacity of almost 1 MW operate. The optimum scenario already employs interconnectors combined with a 51 MW BESS (Figure 6.16). The interconnectors and the 50 MW/150 MWh BESS will expand to 6.5 MW of wind and 3.25 MW of solar added to the existing capacity and support RES expansion across the Cycladic region. Despite the I.x.1.0.a scoring lower generation costs at 60.4 €/MWh, compared to 90.5 €/MWh in IB.x.1.0.a, the power shortages evidenced in the summer months following 2032 demand storage support. It has to be noted that Mykonos BESS provides flexibility and capacity reserves across the Cycladic region and particularly on islands such as Syros and Naxos, where a battery is not deployed to optimize costs.

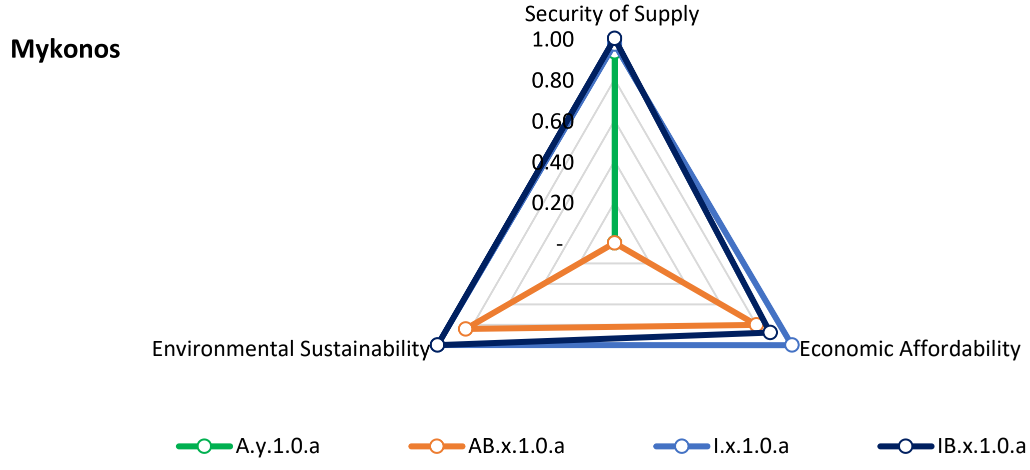


Figure 6.16: ETI performance - Mykonos

Paros' electrical system comprises the following islands: Paros, Antiparos, Naxos, Koufonisi, Shoinousa, Ios, Folegandros, Irakleia, and Sikinos interconnected with MV submarine cables. Paros interconnection was completed in 2020. Since then, it has mainly supplied electricity through the 150 kV subsea cable connecting the system with Syros and Mykonos and following on with Lavrio city in the Greek mainland. According to Figure 6.17, the best possible scenario is the IB.x.1.0.a with 78.8 €/MWh average generation cost and zero locally produced emissions, which proposes the enhancement of the recently installed cables with BESS. In particular, a 180 MW/720 MWh battery will be installed on Paros by 2040, supporting the whole Cycladic islands region, alongside 111 MW wind and 11 MW solar PV, with wind farms located only on Paros, Naxos and Ios islands. Additionally, a 1 MW PHS is deployed on Ios island. Regarding the rest of the scenarios, both AB.x.1.0.a and I.x.1.0.a will experience unserved demand, while the Autonomous BAU case is recording the highest emissions and generation costs exceeding 120 €/MWh.

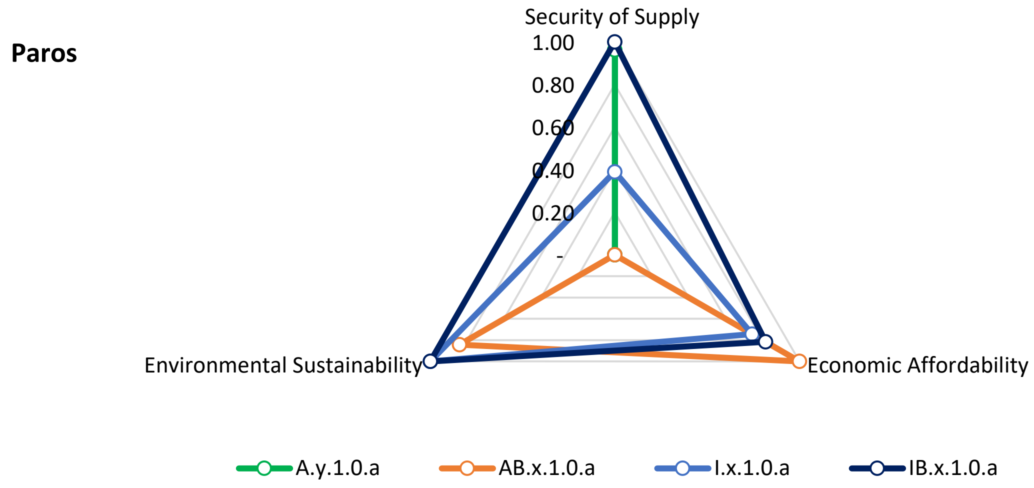


Figure 6.17: ETI performance - Paros

Serifos is a small electrical system in the western Cyclades, scheduled to become interconnected in 2023. The island currently operates only 100 kW of solar PVs. The system invests directly in BESS and RES while eliminating oil in the autonomy. The modelling results show that the optimum scenario could be the Autonomous-Batteries (AB.x.1.0.a) while phasing totally thermal power (Figure 6.18). Such a scenario would propose installing 1.8 MW solar and 6 MW wind, including 6 MW/58 MWh BESS providing flexible services to Milos. On the other hand, the interconnection scenario without storage deployment (I.x.1.0.a) will cause frequent power interruptions during the summer months, and the costs remain high at 192 €/MWh, whereas if BESS are deployed, costs marginally decline at 179 €/MWh.

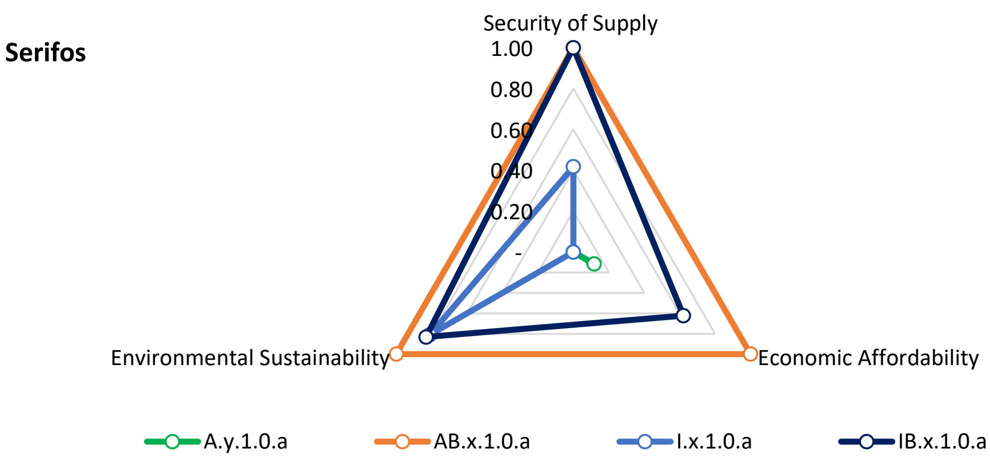


Figure 6.18: ETI performance - Serifos

Syros is the capital of the Cycladic region and the first island to become directly interconnected with Lavrio in central Greece as part of the Cycladic islands interconnection project (Zafeiratou and Spataru, 2016). Following the scenario assessment analysis, the AB.x.1.0.a, I.x.1.0.a and IB.x.1.0.a score similar results. With a marginal difference, the IB.x.1.0.a scores 1 in terms of security of supply and environmental sustainability while concerning economic affordability, it records 0.94 with generation costs at 80 €/MWh, versus 73 €/MWh in AB.x.1.0.a (Figure 6.19). The A.y.1.0.a scenario experiences the worst performance across all indicators except the security of supply. The ultimate IB.x.1.0.a scenario will eventually lead to 15 MW wind and 3 MW solar with BESS support from the islands of Paros and Mykonos.

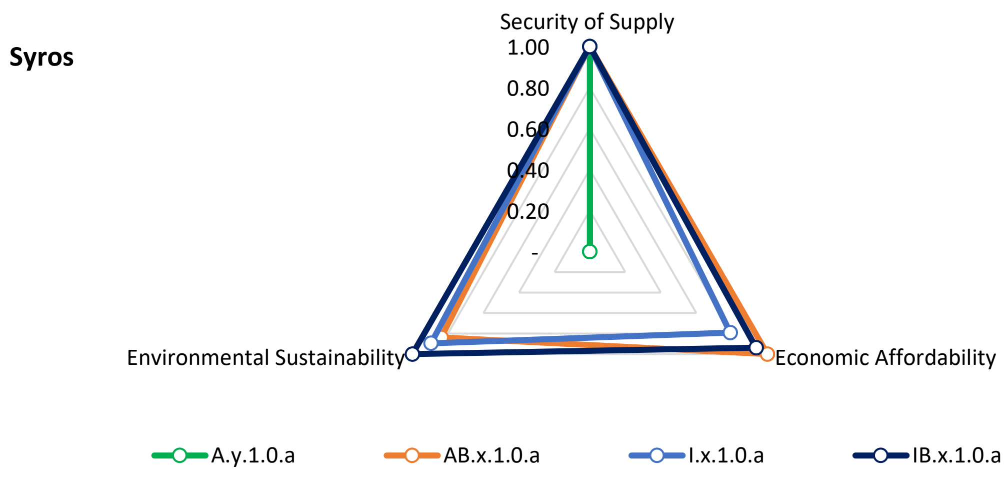


Figure 6.19: ETI performance - Syros

Thera or Santorini, one of the most popular islands in Greece, is connected via MV cable with Therasia, a neighbouring small island. The preferable option for this system is the interconnection combined with BESS, as I.x.1.0.a is recording considerable incidents of load shedding. The IB.x.1.0.a succeeds in securing smooth power supply even during excessive demand peaks while reducing emissions by 84% compared to A.y.1.0.a as depicted in Figure 6.20. Likewise, costs drop to 88 €/MWh compared to 290 €/MWh in a BAU scenario. Overall, 115 MW/460 MWh BESS, 35 MW of wind and 4.4 MW of solar are developed on the island of Thera under IB.x.1.0.a. On the other hand, in the Autonomous-Battery context, costs are further reduced to 60.5 €/MWh. Thera exploits its maximum capacity to deploy renewables with 120 MW wind, whilst BESS is underutilised in such a scenario. Therefore, power shortages are recorded between 19:00 and 23:00. It is worth noticing that Thera phases several complications at least by 2030, following its interconnection. It requires operating local oil-fired generators at the minimum nominal capacity, leading to high generation costs. Furthermore, it welcomes exceptionally high volumes of tourists across the year, with peaks experienced during July and August.

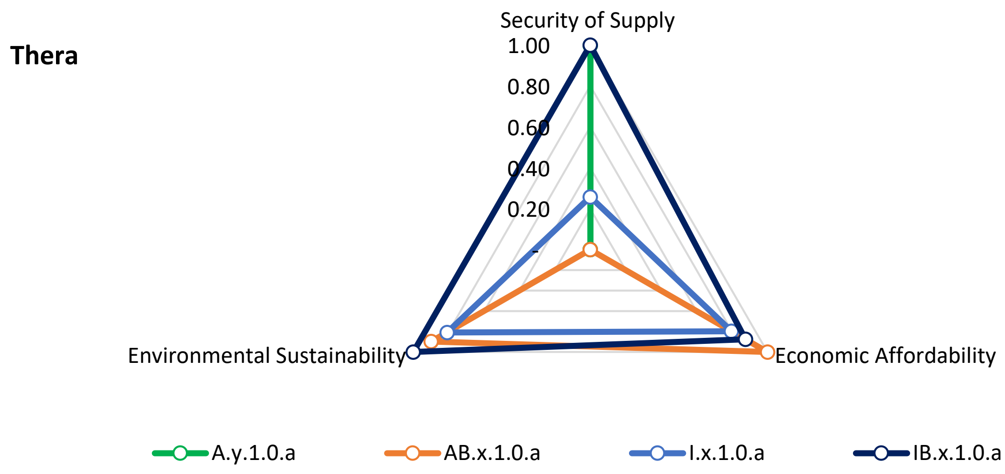


Figure 6.20: ETI performance – Thera

6.2.2.4 *Crete Island*

Crete is the largest non-interconnected island with the highest population and tourists' arrivals, resulting in the highest demand. Crete presents smaller demand fluctuations than other islands as it maintains an adequate load for residential, services and agricultural purposes over winter. Crete completed the first stage of its interconnection in 2021, and the second stage, which will allow its independence from oil-fired thermal generation, is scheduled to take place in 2024. According to Figure 6.21, the optimal solution suggests the interconnection of the island in parallel with the deployment of BESS. In this respect, to secure the system's resilience and reliability, the deployment of large-scale storage is necessary; beyond the 180 MW of PHS, 174 MW/1740 MWh of BESS will be deployed. Here, BESS will also contribute to the baseload compared to smaller systems where batteries inject power mainly in the peaks. Due to increased wind penetration, the western part of the island requires higher flexibility; therefore, 90% of the installed storage capacity is located there. The IB.x.1.0.a scenario also succeeds in recording the lowest emissions. Overall, such a scenario will deploy 1650 MW of wind, almost 500 MW of new solar capacity as well as 143 MW of solar thermal power, and 11 MW of biomass units. The I.x.1.0.a Interconnection scenario scores roughly equal across all indicators, except energy security, presenting minor power shortages during summer peaks. On the other hand, the autonomous options are deemed unsuitable for large-scale power systems such as Crete, with constantly high baseload supply.

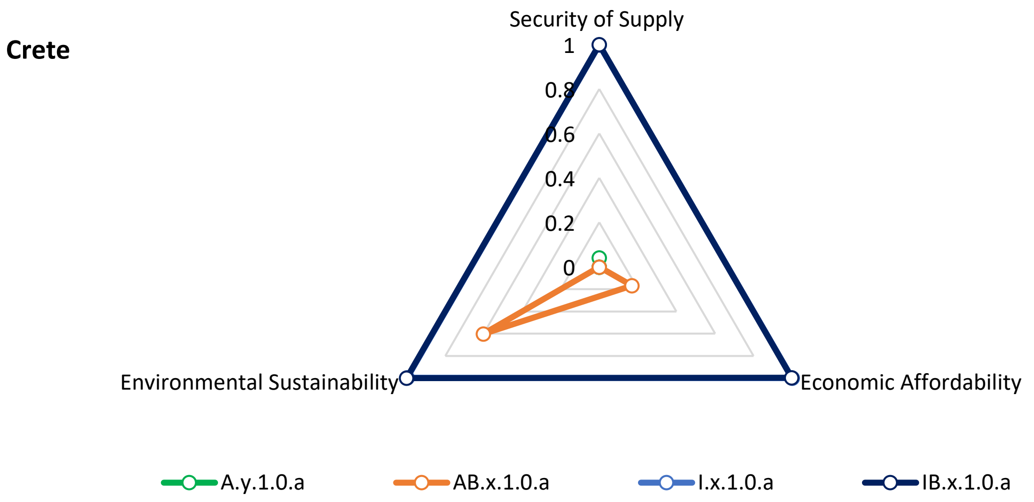


Figure 6.21: ETI performance – Crete

6.3 Key findings and recommendations

Long-term expansion planning and short-term operational simulation provide interesting insights and useful recommendations under the Energy Trilemma Index (ETI) about transforming the Greek islands' electricity generation mix. Among else, planning is a precondition to manage future electricity demand and supply and ensuring the effective operation of the electricity supply sector. Such a process occurs under large-scale RES penetration, new transmission line extensions, and storage technologies for the Greek islands.

PLEXOS software has been employed to build a model for simulating the Greek islands' electricity system. The model is based on the cost-optimisation principles to satisfy the equilibrium between electricity demand and supply in the islands region and conceptually in the Greek electricity system. Certain conditions and techno-economic constraints bind the operation also related to reducing CO_2eq emissions from power generation. The model combines long-term investment planning and short-term electricity dispatch scheduling with stochastic optimisation. Medium-term and PASA simulations are also used to complete the multifarious objectives of this thesis, impacting the system's reliability at various scales. The fundamental questions asked to configure the modelling input assumptions inserted in PLEXOS, which eventually will shape the future decision-making, are related to where what and how future generation, storage and transmission extensions will be optimally deployed and operated.

For all scenarios beyond the Autonomous trajectory, assumptions have been aligned with Greece's ambitious plan for decarbonising its electricity mix, as reflected in the NECP (Hellenic Republic - Ministry of the Environment and Energy, 2019c). These targets go even beyond the European commitments for GHG emissions reduction. Certain scenarios are diversified from the original plan to examine the impact of ambitious policies and strategies. Overall, the key research findings show a decreasing annual natural gas consumption in 2040 by 9% compared to 2016 and 13% compared to 2020 while eliminating lignite. This is attributed to the aggressive penetration of new RES plants, driven by the policy decarbonisation context, leading to high-RES shares that naturally restrict the electricity production of other resources, notwithstanding the increasing system load demand.

The results prove that if Greece needs to meet its EU and national commitments, certain interconnectors must be installed to benefit from renewable energy exports from the islands region. Islands interconnections allow the harmonious distribution of RES in Greece while prohibiting the creation of ‘two-speed territories’ with adverse socio-economic and environmental impacts by relocating 5 GW capacity from the mainland to the islands’ region, excluding offshore and existing installation. In addition, when supported by energy storage, interconnections reduce gaps between demand and supply. This can be particularly important in the current context where the ‘Market Reform Plan’ is applied in Greece, which aims to fully integrate demand response and storage in all the stages of the wholesale markets, including in the balancing (RAE, 2021b). Beyond the direct economic and technical benefits offered, interconnections create a regional super-grid with strategic geopolitical importance, as Greece will continue to be a net importer by 2040, according to the NEC. Therefore, such investments have a catalytic role in significantly reducing the required electricity imports from third countries.

The modelling outputs show that the islands region, which corresponds to 10.7% of the Greek electricity consumption, could facilitate the development of approximately 6.5 GW RES, which represent 29.5% of the total renewable energy capacity in Greece by 2040, corresponding to a 32% share in generation due to increased efficiencies. This potential can be unlocked only if HV submarine interconnectors are submerged across the Aegean Sea, combined with approximately 1.38 GW of battery storage. In this trajectory, the Greek islands transform from net importers in 2030 to net exporters in 2040 annually, with more than 7,000 GWh exports towards the mainland.

The key decarbonisation technologies are wind and solar, while hydro, bioenergy, geothermal and solar thermal could have a complementary role. Regarding energy storage, BESS prevail in terms of flexibility, commercial readiness and costs. Due to lack of space, wind farms are prioritised against solar across the islands. On the other hand, massive solar deployment is anticipated in Greece's central and Northern mainland due to suitable conditions. To optimize the spatial configuration of new installations, areas, where the existing substations lie, could host ‘in front of the meter’ BESS to minimise the land footprint. The renewable energy projects could also be combined with ‘behind the meter’ storage installations. Also, the areas where the existing thermal power stations lie could be restored while creating community energy projects or public recreational spaces. Concerning offshore wind development, it will be developed in specifically designated areas with low environmental and landscape visual impact, while they can benefit from the infrastructure of island interconnections and vice versa. In parallel, they secure the deployment of at least 934.15 MW of clean power with high-capacity factors exceeding 40% while displacing lower efficiency capacity from the mainland.

Considering the high-RES efficiencies, the current underdeveloped state of this geographical area, and the additional costs due to its remoteness, it is of imperative importance to apply dedicated regulated auction schemes for RES aligned with the maximum interconnections transferred capacity. A multipurpose and multistakeholders’ permitting process needs to be established, as local administrations' interests are not often aligned with the national plans. Therefore, the local citizens and communities need to be actively engaged and educated regarding the multifarious benefits of the energy transition. Beyond optimising the ETI, there is also a socio-economic dimension involving mobilising investments on islands that could bring valuable longer-term skilled employed opportunities and regenerate depopulated islands. In this respect, a certain amount of the profits arising from the RES projects needs to be reinjected to the local communities supporting various health, education and infrastructure development activities. Furthermore, ownership models could be offered to the islanders, allowing them to invest in local RES projects through energy cooperatives, accelerating the region's clean energy transition.

6.3.1 Security of supply

An important dimension for sizing the cables beyond the peak summer load is the expected maximum renewable generation that will be transmitted. Aligned with Greece's decarbonisation strategy, a multicriteria analysis is deemed necessary to assess the maximum RES that could be accommodated per island. Small islands which have been scheduled to become interconnected in the short or long-term such as Serifos, Agios Efstratios, Symi or Milos, may not require the support of a submarine cable. Such systems can secure their local supply through flexible, hybrid units combining wind energy complemented by solar and BESS alongside dispatchable renewable energy technologies such as geothermal, which could act as a key balancing technology. BESS utilisation is highly efficient on these particular islands (but not limited to) with increased capacity factors. Besides, the role of BESS is catalytic for ensuring reliability and effective balancing of the islands' electricity systems. Therefore, the model invests in the region as it builds large-scale capacity while supporting the expansion of clean energy, eventually becoming the cheapest electricity source. According to the modelling results, BESS will play a strategic role in systems such as Lemnos, Mykonos, Paros, and Crete once interconnected with large-scale installations providing interregional support. Patmos, Chios, Kos, Skyros, Syros and Naxos are not deploying BESS under the interconnection scenarios relying on storage support installed on neighbouring islands.

To accelerate the development of BESS projects, the Greek government is currently preparing a legislation framework. Such a legislative piece should focus on BESS deployment on islands in conjunction with the recently approved budget of a €1.4 billion scheme to accelerate RES on the Greek islands via energy storage to multiply the benefits for the local systems (European Commission, 2021d). Hence, BESS deployment must be aligned with RES evolution while paving the way for efficient permitting and an uninterrupted power supply. On the technical end, the optimal operational framework should be designated considering the continuation of electrical autonomy or the submerging of new transmission extensions and the impact on the NGS as interconnections will be a considerable driver of electricity demand growth.

The results exposed inefficiencies in lines connecting Lesvos to Agios Efstratios and Lemnos. Furthermore, the cables between Naxos and Mykonos experience congestion issues exceeding 4,000 hours, escalating to 6,000 hours by 2040.

Such phenomenons require a capacity upgrade or an effective demand and supply management at the local level, using BESS and demand-side mechanisms supported under the Market Reform Plan. PLEXOS modelling outputs indicate that the new alternative proposal for a direct line between Kos and the central part of the Greek mainland (I.x.1.0.b) would reduce the region's exportable capacity; therefore, it is not recommended. Besides, under this scenario, additional unserved remand is recorded by 23% compared to I.x.1.0.a.

The imbalance between demand and supply is reflected by a variation in the system frequency, which prohibited the integration of high shares of variable RES in islands power systems. The existence of interconnections eliminates the barriers related to the technical minima of local oil-fired power stations and the dynamic constraints of renewable energy. Also, the reserves sharing option is enabled, allowing owner stations in the mainland to provide balancing services to the islands region and vice versa. Therefore, the risk of the ancillary service is reduced. However, replacement provision as highly interdependent to lignite-fired production is estimated to create 4,370 GWh of shortage unless electricity storage in the form of a hydro pump or BESS supports the system. Alternatively, although there is currently no regulation framework, less-stochastic RES, particularly those converter-interfaced, may provide the whole range of ancillary services to the system, including tertiary, under a relatively higher cost.

As interconnections facilitate renewables growth, the modelling results highlight that under a less-ambitious RES growth scenario where capacity is reduced to half, i.e., 2.6 GW, a 44% increase in unserved demand will be recorded considering the whole projection horizon compared to the original scenario. On the other hand, in the Autonomous Pathway, the inclusion of an additional 500 MW, increasing the local renewable capacity to 1.6 GW, will reduce unserved demand by 49%.

Reliability indicators such as the CRM increase across the Autonomous Battery scenarios exceeding the 50% threshold as significant RES capacity is added. The interconnection scenario demonstrates acceptable CRM except for Mykonos and Patmos islands due to relatively lower generation built by 2030. However, such a scenario still experiences high LOLP for several island systems. In contrast, through the decade of 2030-2040, reduced LOLP is observed on Crete and Paros, as considerable generation capacity is built. If storage systems are deployed alongside submarine transmission extensions, the LOLP lowers close to zero across all islands by 2040, except for Patmos, Symi and Syros, where little impact is evidenced if BESS or additional RES capacity is invested without considering the impact of an interconnected network. On the contrary, the multi-regional LOLP reduces across all systems, although certain Dodecanese and Cycladic islands, as well as Crete, maintain a relative vulnerability if BESS are not coupled with interconnectors, requiring reinforcement in their generation or transmission capacities before 2030. Specifically, large-scale battery and pumped hydro systems become essential to secure the continuous power supply on the island of Crete by 2030. In light of these findings, there is a requirement to stream state aid urgently to Crete, according to the European Commission (2021d). Alternatively, NG, in conjunction with renewables, could balance the system without however abolishing emissions at the local level. The results demonstrate that using one reliability indicator is not always indicative given the requirement to measure the temporal variability and the qualitative and quantitative characteristics of the power system's elements for providing comprehensive conclusions.

6.3.2 Economic affordability

The monetised impact of future interconnections shows that 11€ billion could be saved compared to the continuation of the Autonomous operation (A.y.1.0.a) between 2020 and 2040. The involvement of 10.5 GWh of storage capacity under the Interconnection-Batteries Scenario (IB.x.1.0.a) increases expenses by 2€ billion. At the same time, it reduces the average generation costs at the national level by 3% compared to the Interconnection scenario (I.x.1.0.a), and by 10% compared to the BAU case with average prices of 66.4 €/MWh. The impact is intensified to 42% at the regional level, with an average cost of 94 €/MWh. The highest cost decline of 50% is recorded on Crete, Mykonos and Thera due to increased touristic demand creating a larger reduction margin. On the contrary, the respective Autonomous-Batteries Scenario (AB.x.1.0.a) triggers large-scale capital-intensive investments with additional costs of 12.4 € billion compared to the BAU Autonomous case. Nonetheless, a considerable drop above 70% is recorded on a few islands adopting the AB pathway, such as Symi, Serifos, and Skyros, with a large-scale RES penetration exported via interconnectors. There is a typical pattern for reducing the average levelised costs between 2030 and 2040, since the first bulky batch of renewable projects is anticipated following the submerge of the interconnection cables between 2025 and 2030, while a large segment is completed by 2040.

Crete and Rhodes, the two largest island systems, record lower local levelised costs concerning the generation capacity as they can deploy different technologies at larger scales. For Crete, the option to introduce locally NG facilities for electricity production and heating (I.x.1.0.f) could prove a strategic decision, with multiple economic benefits for the island, as the southern part of Crete is rich in hydrocarbons while reducing levelised costs by 24% at 91 €/MWh in 2040[50]. Following 2040, NG would avoid submerging the third cable between Central Greece and Crete in the long run. It also stabilises the local grid between the Dodecanese islands and Crete while providing further independence. On the downside, NG entails price vulnerability and considerable emissions while keeping Crete and Greece dependable on conventional fuels. For the Rhodes system, the Autonomous pathway with battery storage support considerably reduces power generation costs by 52 €/MWh, at 65 €/MWh, as it allows a double wind penetration to the local system compared to the I.x.1.0.a scenario.

A PSO scheme will remain pertinent if the Autonomous-Batteries or Interconnection pathways are not finally applied. The purpose of such a unified price system is to ensure fair prices and avoid inequity between the habitats of the mainland and the Greek islands; however, it does not enforce a pricing mechanism that reflects the actual cost of electricity and, consequently, supports the clean

[50] Considering fuel price forecasts as indicated in WEO 2018.

energy transition. Furthermore, uncertainty in fuel prices may lead to deficits and additional economic disincentives for the PPC, the only utility producing thermal generation and one of the few suppliers on the islands acting as the 'last resort'. PPC is also imposed to long delays before getting remunerated for the additional generation costs.

In this respect, the total PSO amounting to 22 billion € for 2020-2040 could be provided as a state subsidy to fund the construction and operation of new infrastructure, clean energy and storage projects. It could also support local energy cooperatives where citizens jointly own and participate in renewable energy or energy efficiency projects inspired by REScoop.EU (2021) through remuneration schemes or direct grants. When combined with state aid support, public funds could leverage European Regional Development and Structural funds that have already financed the interconnection of the Cycladic islands, Crete's interconnection, and Telos Astypalaia projects. Furthermore, support from organisations such as the European Investment Bank (EIB) and the European Bank for Reconstruction and Development (EBRD) could cover projects' financing requirements with reduced interest rates. In this context, Greece also has the chance to benefit from the recovery plan to help rebuild a post-COVID-19 greener, digital and resilient energy system on the Greek islands (European Commission, 2021c).

6.3.3 Environmental sustainability

Environmental sustainability measured in CO_2eq emissions shows that the electricity generation mix in the islands' region has been marginally more carbon-intensive by 7% than the mainland across the projection horizon. Exceptions are the non-CO_2 emissions such as NO_x and SO_2, which are 55-75% higher in the NGS due to the extensive use of lignite. In the past, CO_2 emissions prices remained low; therefore, there was no economic motive to switch to clean energy technologies. In parallel, there was an absence of a clear policy framework imposing the ban on carbon-intensive fuels for electricity purposes. If a BAU scenario continued beyond the economic consequences, it would also cause significant environmental impacts with more than 64 $MtCO_2$eq emissions released from power generation on the Greek islands over the 20-year projection period. In

2040, the Autonomous-Batteries scenario successfully lowers emissions at a regional level up to 52% compared to the BAU case and 79% compared to 1990. Nonetheless, this is insufficient for reaching the EU and national targets, whereas wind deployment overrules spatial restrictions.

On the other hand, a scenario aligned with the NECP strategy, including interconnections and BESS (IB.x.1.0.a), may lead to 74% emissions reduction compared to the BAU in 2040 and 88% compared to 1990, demonstrating the only feasible option for reaching the national targets of 7 MtCO2eq in 2040. At the regional level, the gap intensifies to 99% between the two scenarios by 2040 and 74%, considering cumulative emissions between 2020 and 2040. Concerning NO_x and SO_2, a scenario imposing generation restrictions on carbon-intensive fuels when combined with transmission extensions and rapid RES acceleration may succeed in an 88% decline for NO_x and SO_2 compared to 2016 on islands. Beyond Crete, with a considerable margin for emissions reduction up to 80%, Samos, Lesvos, Milos, Mykonos, Paros, Syros and Serifos attain more than 70% carbon emissions decline compared to the BAU case.

6.3.4 Demand impact

Little effort has been placed on successfully implementing energy efficiency policies concerning buildings and transportation on the islands. The Greek government practices focused on subsiding modular diesel units over the summer months to cover excessive peaks. That could have been alleviated if flexible balancing mechanisms were promoted in parallel with economic support and incentives (e.g., tax relieves) for deep renovations in the tourism sector, eventually reducing peak demand. However, the techno-economic and environmental benefits of infrastructure investments described before can only be valorised if they go hand in hand with incentives to promote energy efficiency. Such measures, particularly in buildings, could be a crucial catalyst for ensuring the systems' resilience and avoiding dispatching expensive peaking power units. Energy efficiency policies need to be customized at the local scale, considering the regional requirements mainly concerning the tourism industry. In parallel, although not modelled herein, smart energy systems and demand response mechanisms may play a key role in balancing demand and supply effectively under a high renewable share context while smoothening the ‘duck effect’ from the daily demand profiles.

Two principal scenarios were explored in the modelling exercise: the High-Efficiency Demand Scenario (High_Eff), with aggressive renovation rates also driven by relevant economic growth, and the Low-Efficiency Demand Scenario (Low_Eff), with moderate projections for efficiency improvement and medium renovation growths. The methodology applied proposes energy savings by replacing old inefficient appliances and lighting systems with new ones, by introducing clean and efficient systems in the heating, water heating and cooling sectors and by reinforcing the building envelope (introduced through the renovation parameter) with new insulation materials, shading systems, planted roofs etc. Finally, economic growth and consumers' behaviour towards more environmentally friendly practices are introduced in the model as additional parameters. These options were simulated in the ISLA_EGI model, and the results were introduced in PLEXOS through the respective Autonomous and Interconnection Scenarios.

The benefits of applying ambitious efficiency measures included in the High_Eff scenario may be reflected in lower generation costs, transmission capacity and generation deferments. The Greek islands have a large margin of 1,270 GWh/year which could be eventually saved. This is translated into a 26% improvement against the Low_Eff Scenario envisaged here in 2040 and 35% against the national demand projections from 2007 as published by the European Commission (2021a). Notably, the southern regions such as the Dodecanese, Cycladic and Crete demonstrate the highest potential in terms of energy savings ranging between 20 and 30% by 2040 compared to the BAU demand scenario. Nonetheless, the results highlighted that the margin for energy efficiency improvement on the Greek islands is relatively lower compared to the mainland, with targets exceeding 32.5% already in 2030 as the services sector is expanding more aggressively. This is anticipated given the higher socio-economic demand growth and increase in tourism arrivals, showcasing that technological improvement broadly impacts the commercial and tourism sub-sectors. Remarkably, the tourism sector exhibits sufficient margin for efficiency measures to rationalise demand for accommodation. In contrast, there is an imperative need for higher impact measures in the commercial sector.

Overall, considering the entire projection horizon, electricity generation costs could be reduced by 3% and emissions by 16.5 % in the region while almost eliminating unserved demand if energy efficiency practices are adopted rapidly on the Greek islands in the interconnected context. If energy autonomy continues, the impact is amplified to a 21% reduction in generation costs and 27% emissions. At the system level, the differences are limited to a 2.5% emissions decline if the islands' interconnection occurs, while a minor impact of 0.5% is recorded concerning the system's power generation costs. The impact is respectively 3% and 4.2% in the autonomous setting.

The Low_Eff approach will lead to high demand levels similar to the BAU figures projected previously by public authorities. The impact of tourism is exceptionally important as an increased volume of visitors is expected on the Greek islands distorting their seasonal demand profiles with extreme peaks over the summer months, especially when combined with increased temperatures. Therefore, following the islands' interconnection, the increasing demand growth trends force the system operators to call for investments in peaker plants, mainly in the mainland, to cover extreme loads recorded for cooling and other purposes.

6.3.5 EVs impact

The current trends show that EVs will be massively deployed over the coming years (European Alternative Fuels Observatory, 2021). Hence, additional loads will be stressing the system, necessitating smart charging and discharging techniques. The simulations show that the V2G scenarios are the principal charging patterns that bring optimum results by reducing load shedding and curtailment in the islands. Particularly, bidirectional (V2G) and, on certain occasions, scheduled charging could support smoothening the daily demand profiles on the Greek islands, showcasing that indirect, cost-driven charging patterns coincide with lower demand periods. Consequently, the results prove that electric mobility could increase the dispatch of renewables and mobilise additional capacity up to 720 MW by 2040 in the autonomous context, assuming an ambitious EV deployment plan (S2) and 600 MW if interconnections are realised.

As the renewable generation is highly seasonal and stochastic, there is not always one optimum solution, highlighting the benefits of a flexible, diverse charging system. The outcomes showcase that daily morning charging could support the injection of more solar power when the demand and the irradiation are relatively high, whereas the scheduled daily scenarios fit well during wintertime. In the interconnected context, the ultimate performance of the V2G scenarios increases RES participation to 12% in 2030 and 7% in 2040 under S1, while in S2, it is contained to 5% due to increased demand.

EVs' provision of ancillary services such as active power regulation and reactive power support is more regulated in the smart grid context, primarily if bidirectional technology is employed, to offer upward and downward services (Khan *et al.*, 2018). Aggregators need to be established representing EVs charging loads and potential power to be dispatched in ahead and real-time energy markets supervised by the distribution network operator (HEDNO). Users will charge and discharge their vehicles during the optimal designated periods through such an intelligent platform while providing ancillary services to the grid, such as frequency regulation. Coordinated control among EV users, aggregators and power plants will reduce costs and avoid extensive uninstructed energy deviations, which may cause system losses and imbalanced voltage profiles.

Most charging patterns will increase emissions across the years in the Autonomous context, coinciding with a relative reduction in RES share in the mix, up to 31% under S2 pubic charging during the summer. Exceptions remain the V2G scenario which restricts charging during peaks and reduces emissions on an annual scale under a moderate deployment scenario (S1). However, this is not possible when EVs increase fast (S2), leading to additional thermal power dispatch. By 2040, the increase is contained across most weeks but the winter months due to the requirement to commit oil-fired units. On the contrary, in the interconnected context, almost the majority of the charging patterns will lead to emissions reduction attributed to higher RES generation and low carbon power flows from the mainland. Once interconnected, the impact of electric mobility in the islands' region takes nationwide dimensions as a significant amount of demand is met by imported energy. Hence, scenarios such as the scheduled daily and V2G-restricted result in CO_2eq emissions reduction up to 5.9% at the system level, highlighting that if a high number of EVs is introduced on the Greek islands, a parallel generation and transmission capacity enhancement is required.

Beyond the direct benefits of EVs regarding electricity use, there is a positive environmental effect in the transport sector. This is evident only if there is high-RES share participation in the generation mix. For the effective contribution of EVs in the ETI, the Autonomous case sees limited benefit from EVs deployment, whereas, under the Interconnection scenario, emissions are reduced by 12,500 tCO_2eq under S1 and 150,800 tCO_2eq under S2 scenarios by 2040. The results prove that the carbon intensity threshold for a region is circa 460 kg/MWh, above which is preferable to adopt a non-electric mobility option.

Considering power generation costs, if EVs are deployed in the Autonomous context, the system will experience an increase in generation costs up to 31% in 2030 and approximately 18% in 2040 due to oil-fired generation. Nevertheless, charging scenarios such as morning and V2G can potentially lessen costs up to 20% under a moderate EV deployment and 18% under an aggressive S2 scenario by 2040. If interconnections are realised in most scenarios but the opportunistic ones drop costs up to 31%, mainly over the average week in 2030. The morning scenario minimises costs up to 14% during the maximum week in S1 and the V2G up to 13% during the minimum week in S2.

Overall, the results showcase that EVs may be deployed on the Greek islands under a secure, interconnected network in parallel with smart infrastructure deployment to facilitate scheduled and bidirectional charging. If an ambitious EV growth scenario is realised, the impact on the local grid is maximised; therefore, HEDNO and IPTO should include the EV loads gradually in their ten-year transmission plan. It is proved that electric mobility will have no positive environmental impact on the islands while keeping their energy autonomy, even under a high-RES scenario share. Suppose the autonomous state proceeds, the sizing of the hybrid systems has to be adjusted to meet EVs requirements in addition to the existing demand.

6.4 Contribution and novelty

The Greek islands' electricity system has drawn attention internationally due to its dependence on oil-fired generation, failing to meet electricity demand in a reliable, affordable and sustainable way. A thorough literature review has been carried out revealing the lack of integrated methodologies considering: the demand dynamics, coupling short and long-term modelling, spatiotemporal resolution, and the inclusion of innovative technologies such as BESS, electromobility, renewable resources and new infrastructure developments while respecting the individualities of each island electrical system.

Accordingly, a comprehensive, overarching methodological approach has been employed herein with high replicability due to its universal setup, assuming electricity is in the spotlight of the future decarbonisation strategy. The overall goal has been to reach general conclusions via scenario modelling on the impact of stochastic variables which mainly affect the electricity system operation (i.e., system load, RES and BESS capacity, submarine interconnections, fuels and CO_2 prices, etc.) usually influenced by policies and economic parameters against the Energy Trilemma Index (ETI).

To address the lack of data related to long-term demand forecasting, the ISLA model was employed, modified to ISLA_EGI to focus exclusively on the the Greek islands' electricity sector. The model integrates a broad set of policies and techno-economic assumptions capturing the technology transition as well as historical and socio-economic data through a hybrid approach. The methodology covers all electricity systems individually while building up a database from two household surveys conducted during the past decade (Hellenic Statistical Authority, 2013, 2016b). The framework adopted splits down demand into its main end-uses allowing for solid recommendations regarding the potential to reduce power consumption. Such a long-term demand forecasting approach accompanied by extensive data processing through data manipulation and algorithms built-in MS excel was applied for the first time.

The temporal resolution in PLEXOS modelling combines long and short-term dynamics while considering annual demand forecasts in conjunction with hourly load profiles. The results from the ISLA_EGI model are inserted as inputs in PLEXOS while coupling demand and supply scenarios by soft-linking the two models. Also, hourly variable RES dispatch profiles have been included to reflect their stochasticity.

Considering the spatial resolution, none of the reviewed studies has covered so far, the islands' systems at such a granular level, including a single node for every island in conjunction with the NGS represented by six nodes. Usually, modelling exercises examine one single or a group of islands, neglegting interlinkages between the islands and the mainland. Transmission expansion using the linearised DC-OPF method and generation expansion are implemented driven by cost-optimisation principles in PLEXOS bound by the modelling inputs and constraints. The entire interconnection plan is evaluated for the first time under a single modelling exercise against EU and national targets as reflected in the NECP and current operational standards. Sensitivity analysis is applied considering a wide range of socio-economic, technical and policy-driven assumptions. Energy storage in the form of batteries is addressed without excluding the parallel deployment of other storage technologies and submarine interconnections while emerging the benefits of their simultaneous deployment. Furthermore, the current study presents a complete, universal methodology to simulate EV loads in PLEXOS software while exploring deployment and charging strategies. The results provide the first-ever assessment of electromobility on the Greek islands' local grid.

The analysis succeeds in identifying the optimal solution within the ETI framework, which is the combination of interconnection infrastructure alongside energy storage at the utility-scale level across most islands. In contrast, certain smaller islands identified as outliers may remain non-interconnected. The IB.x.1.0.a scenario highlights the synergies between the two technologies while allowing the Greek islands to become net exporters by 2040 across certain weeks of the year. Once EVs are introduced, the system presents its optimum performance when applying bidirectional (V2G) charging.

Such an innovative methodological approach provides a suitable decision support framework for policymakers to assess the impact of future interconnections and novel technologies in the Greek islands' region and design inclusive strategies for their systems planning and operation under a wide range of scenarios. Additionally, the methods applied, including bottom-up and top-down approaches, the technical parameters and operational constraints, the sizing of BESS, and the EV charging simulations, have high replicability across other islands and regions with similar characteristics across the world.

6.5 Limitations and recommendations for future research

6.5.1 Demand modelling in ISLA_EGI

The baseline year reflected in the hourly demand profiles is 2016, as aggregated demand is usually made available to third parties with a time lag of 2 years. The demand database built to provide future household projections for that year relied on a 2012 survey complemented by 2016 data. This is due to the unavailability of more recent data as the census is repeated every ten years. A more recent and extensive database would increase accuracy while reflecting the latest trends in consumers' behaviour, the type and efficiency of appliances etc. For Skyros, there was a lack of demand data available.

Projections for residential demand profiles relied on regression analysis correlating historical national and regional figures around GDP, population, and the number of households considered as independent variables. However, in practice, all three variables and particularly the population and the hh number parameters are associated, causing multicollinearity, affecting the actual demand output vaguely. Regardless of the moderate degree of multicollinearity according to the variance inflation factor equal to 3, an alternative would be to eliminate or combine these two variables, perform principal components analysis or partial least squares regression to optimize the statistical accuracy (Frost, 2017).

Considering the services sector, the available data sources were extensively manipulated based on statistics deriving from energy performance certificates. Despite the sufficient coverage of buildings included, there is a higher degree of error related to the electricity consumption configuration than the residential profiles. Additionally, the data related to the public, industrial and agricultural sectors were inserted in ISLA_EGI at an aggregated level, without considering the end-uses breakdown, due to their small share in the total demand. The accuracy of ISLA_EGI can be improved by disaggregating these sectors when data become available. Also, demand inputs concerning all sectors relied on NUTS-2 and NUTS-3 regional level statistics, a limitation that could be addressed if more granulated data becomes available at the regional or nodal level.

The demand projections have been treated with an annual time step in this context. In future research, hourly or even sub-hourly modelling will be required to capture demand sensitivities while exploring the impact of end-uses energy efficiency, storage, EVs and demand response mechanisms daily, as extreme peaks are usually exhibited during summer evenings. Instead of investigating merely the impact of demand on electricity prices via PLEXOS, future work could also involve reciprocal analysis exploring the impact of electricity prices on demand through ISLA model. That could be achieved while increasing the number of scenarios to assess the acceleration of energy efficiency measures and clean energy investments in relation to electricity prices and therefore demand levels.

6.5.2 Scenario modelling in PLEXOS

Discrepancies were recorded during PLEXOS validation concerning the long-term expansion planning, related to the lack of exhaustive technical operation assumptions. Except for the Crete and Rhodes islands, where the fuel consumption performance at different operational levels was provided, most of the islands used assumptions identified in the literature. Additional reasons may be the lack of a detailed representation of the HV grid at the island level and the use of rounded relaxation, which reduces the accuracy as well as other limitations failing to capture unforeseen real-life events.

Consumption demand profiles were inserted per transmission region (AES). Hence, load participation factors were assigned on each island/node based on tourism and local population consumption assumptions. Such limitations could be addressed if access was granted to consumption data at each MV or HV substation per island. Other possible ways to enhance accuracy would be to increase the LDC time-slices or the dispatch granularity from quarterly to monthly or weekly; however, significantly higher computational time would be required, which could be addressed mainly with the use of supercomputers. Additionally, expanding the projection horizon to 2050 is possible where the longer-term benefits of interconnections and other technologies will be unfolded.

Regarding scenario analysis, despite the large number of trajectories deployed, interlinkages between certain indicators could be further explored. For example, the impact of fuel prices on electricity demand and supply is not endogenously analysed. Future research could combine fuel price scenarios and their impact on the development of RES as the cost of fossil fuels, in the given context, affects electricity prices considerably and, consequently, the CAPEX of renewables. In this respect, sensitivity analysis on the cost of renewables and battery storage technologies could capture the interrelations between electricity prices and renewables growth, directly linked to the electricity fuel mix. PLEXOS allows the use of shadow prices and complex functions to link these variables. Beyond the impact of electricity prices, the scenarios adopted herein could be combined with different technology learning curves affecting the cost of RES, storage but also submarine transmission lines to reflect the various trends and the effect on renewable energy growth. Other useful approaches could sensitize the inflation or WACC factors and their impact on the Greek islands' transition.

It would also have been preferable to optimize the full calendar year instead of selecting three representative weeks capturing the main seasonal variations concerning short-term dispatch scheduling. Such a case would have allowed emulating seasonality and extreme weather conditions more effectively across the year while enforcing fully operational constraints concerning thermal synchronous generators and BESS. For example, modelling instant and unforeseeable demand for cooling and heating preceded by periods of moderate loads would allow capturing weather uncertainty and the needs for capacity and spinning reserves in such events.

Future research could focus on testing demand response techniques combined with hourly and sub-hourly modelling under such events straining the system or during periods of low-RES availability. Demand response through smart systems could be incorporated in PLEXOS via flexible loads such as EVs already captured but also through regulated peak shaving and shifting techniques to low-cost periods for specific non-essential processes. The implementation of such activities could be adopted again through shadow price-driven mechanisms in PLEXOS using reflective incentive payments. Such a case would lead to smoother demand profiles, reducing unserved demand and curtailments, leading to lower costs and fewer investments in generation storage and transmission capacity. The most applicable sectors are related to the industry with a limited impact on islands. Also, residential and services sectors could be incorporated as long as the flexible loads do not impact their operations. Although market balancing is not incorporated, it would have allowed exploring the system's dynamics while providing ancillary services under high-RES penetration conditions. It can also test the specificities of the islands' participation in the national day-ahead market following their interconnection.

Further limitations could be related to the capacity factors considered for hydro units, which do not reflect the reality as there are deviations related to weather data through time not captured in the model. The 30-35% constraint of RES penetration on small island systems is nowadays considered conventional, while the modelling exercise could have incorporated this limitation on a more flexible basis in relation to the size of the system through the involvement of power electronics such as smart energy controllers beyond storage. The parameterisation of controllers and BESS could allow the introduction of larger levels on RES, which traditionally do not provide spinning reserves under the autonomous state; this could be further elaborated in future work. Last but not least, the actual impact of power flow exchanges with third countries was out of scope; therefore, the model incorporated imports as inputs. A more extended version of the current model would test the interconnection impact with neighbouring countries in an interconnected Greek islands' system.

Regarding the operation of the EVs, the transmission and distribution networks are not included, resulting in a loss of accuracy regarding the actual impact of EVs on the grid and the necessary upgrades required. Here EVs operate considering only the HV transmission lines between the nodes at the system level. Moreover, islands' operation at the electricity market level would have emerged interesting insights around the optimum bidding strategies for maximizing their revenue streams and their impact on the wholesale prices.

This research project emphasized storage technologies such as battery electricity storage, hydro-pump and thermal storage combined with solar thermal technology. Hydrogen technology could be included in future work as PLEXOS tailor-made tools were recently launched to measure Power-to-X and sector coupling impact. Future work could also involve enhancing PLEXOS objective function with more external categories related to the socio-economic factors such as employment, national and regional welfare and health.

Finally, learnings from other systems under rapid transition expose criticalities due to an increase in the systems' complexity and low inertia levels, highlighting that the current (N-1) security standard with an additional reserve may not suffice future systems' security at a global scale (Bialek, 2020). Hence, the thesis results may serve as the basis for future work regarding improvements in monitoring and controlling the islands' power systems and the overall systems' design criteria.

6.6 Concluding remarks

The work described in this thesis was inspired by the meticulous characteristics and structural weaknesses encountered in the Greek islands' region resulting in the absence of a reliable, clean and affordable electricity system. Among other practical handicaps, this is translated into low-RES penetration, far behind the national and EU average, frequent power cuts and high generation costs remunerated via the PSO. In light of the major reforms across Europe to combat the climate crisis, the Greek islands shall not remain inactive as they offer high wind and solar potential that could replace conventional fuels used currently for power generation. However, infrastructure upgrades and investments in storage solutions were only recently approved due to the oil-fired generation restrictions imposed at the European level.

This research project focuses on the Greek islands' electricity system, which is responsible for more than 30% of the final energy consumption in the region while exploring scenarios aligned with the Energy Trilemma Index. The underlying objectives are: to assess the impact of future demand scenarios incorporating energy efficiency policies and EVs penetration, how submarine interconnections and BESS could contribute to the future electricity security and supply of islands power systems, to detect the least-cost electricity mix, and to calculate emissions. Also, sensitivity analysis is applied considering a wide range of stochastic assumptions that test the system under various techno-economic conditions.

As part of the methodological approach adopted, energy planning and operational assessment were applied to provide a conceptual and methodological framework to design energy transition on the Greek islands strategically. Two models were employed and further developed: I) the ISLA_EGI model was adapted after the ISLA model as described in Chapter 3 to produce two demand scenarios (High_Eff and Low_Eff), and II) PLEXOS, a commercialized tool for planning, simulating and optimising electricity and gas markets presented in Chapter 4. PLEXOS has been developed for the Greek islands for expansion planning to secure the necessary investments for the future electricity system. Also short-term dispatch was employed to simulate with hourly resolution the dispatch of the generation capacity under four principal Scenarios: Autonomous (A.y.1.0.a), Autonomous-Batteries (AB.x.1.0.a), Interconnection (I.x.1.0.a) and finally Interconnection-Batteries (AB.x.1.0.a).

Overall, one of the key conclusions of this research project is that Greece will align with its national and EU commitments only through investments in submarine transmission infrastructure coupled with storage for balancing the local grids. These investments are considered strategic, capital-intensive, and essential interventions to support the islands region and, consequently, Greece becoming a net power exporter. This projection points out the consequent economic and environmental benefits of reducing generation prices by 42% at the regional level and 10% at the national level compared to a BAU (A.y.1.0.a) scenario and in parallel avoiding a total of 22€ billion representing the state oil subsidy - PSO. Emissions are reduced by 74% nationally and 99% regionally under the IB.x.1.0.a scenario while reaching national and EU targets by 2040. Also, any severe power outage event is abolished. The ultimate benefits of a High-Efficiency demand scenario in the region show further reductions of 2.5% in emissions over the projection horizon at the system level. Overall, the reduction in contrast to the 1990 levels shows a decline of 88% under the Interconnection-Batteries (IB.x.1.0.a) Scenario considering the whole Greek electricity system. The results also proved the importance of multifarious energy planning in certain small islands such as Agios Efstratios, Milos, Serifos and Symi, an autonomous BESS system proposed under the AB.x.1.0.a scenario proves more profitable than interconnections while securing a smooth power supply.

In complementarity, the operation of EVs on the Greek islands highlights that only V2G scenarios and, in some cases, scheduled unidirectional charging can reduce carbon emissions up to 5.9% while supporting further renewable energy investments when combined with interconnections and utility-scale storage. Also, in the same context, replacing ICEVs with EVs will lead to 150,800 tCO_2eq emissions savings under the S2 ambitious scenario by 2040.

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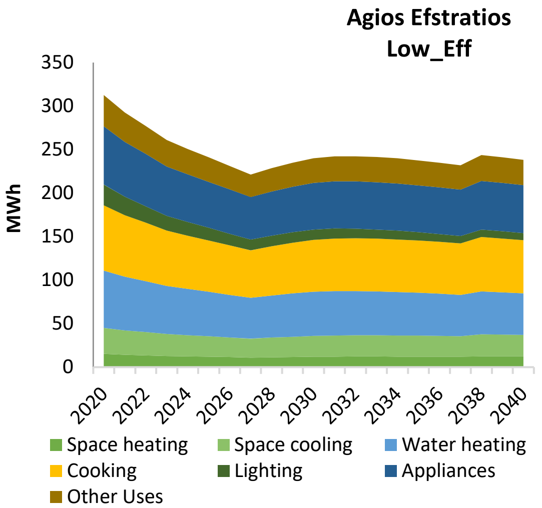
ANNEX I.a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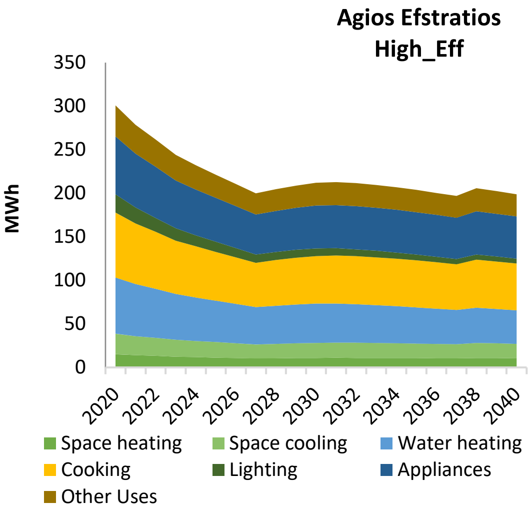
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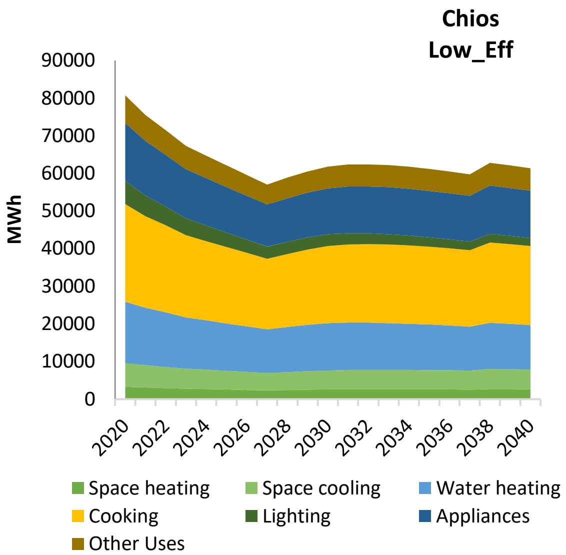
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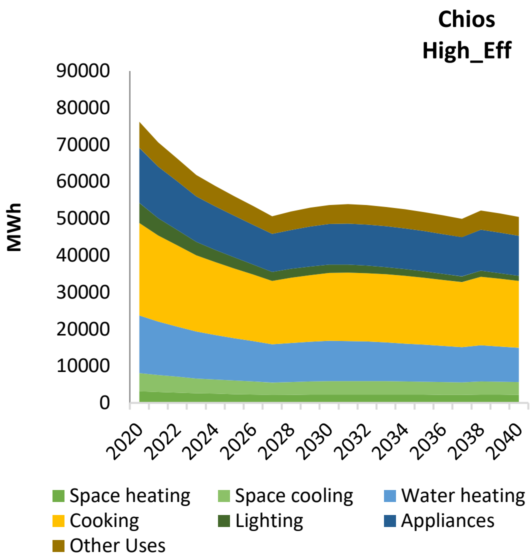
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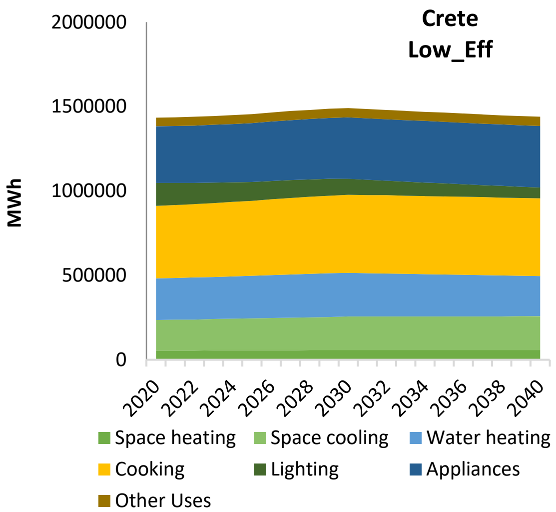
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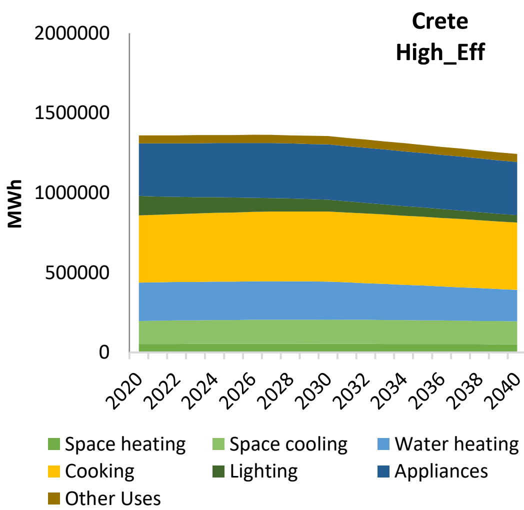
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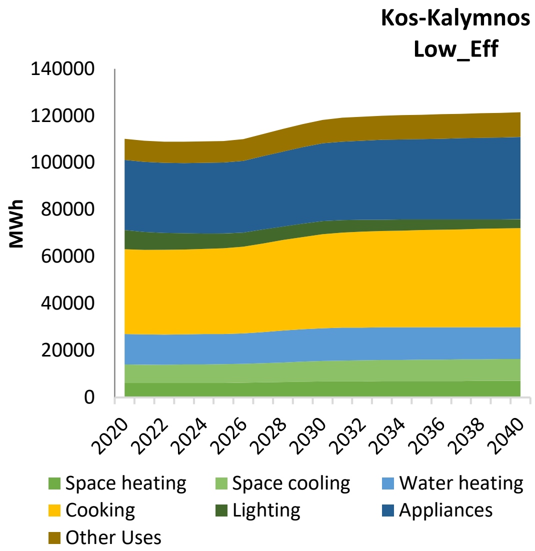
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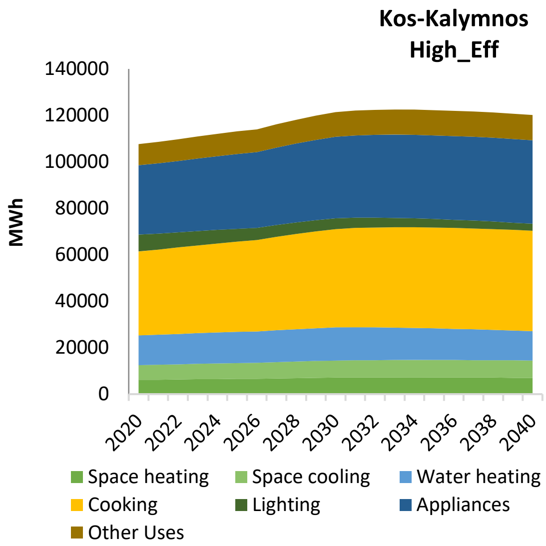
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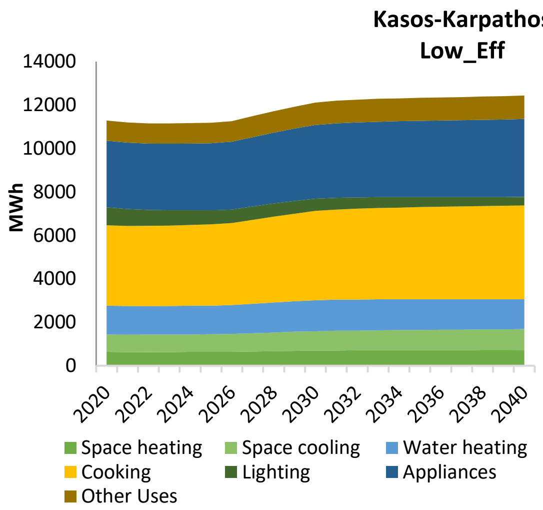
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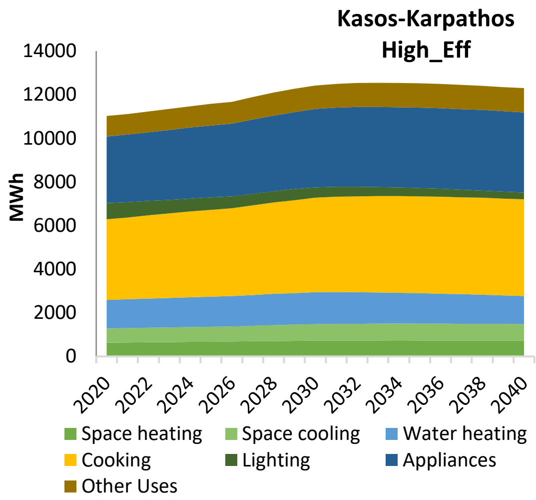
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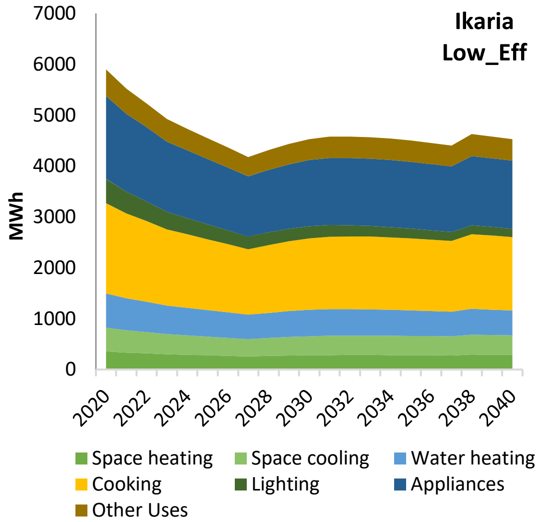
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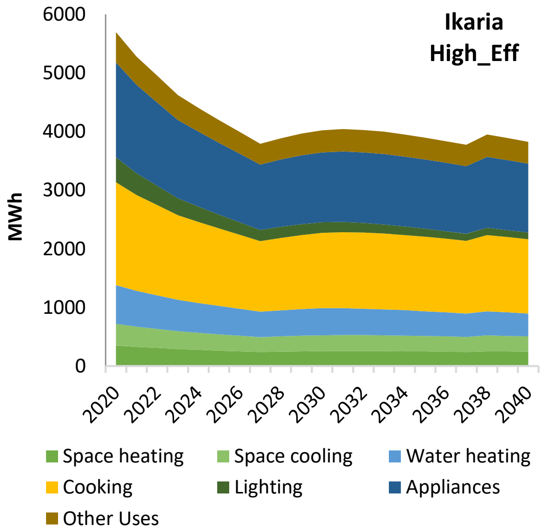
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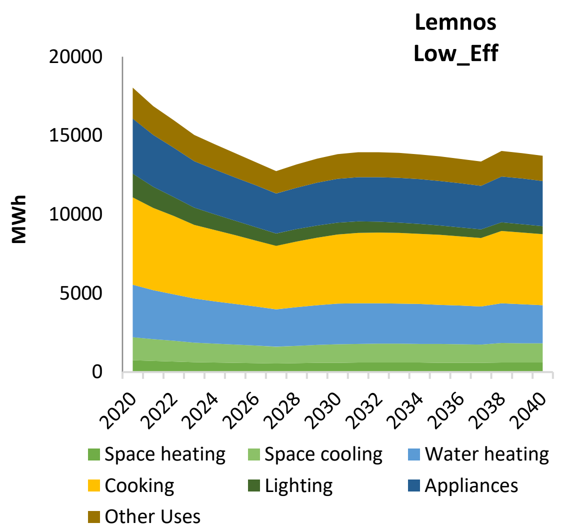
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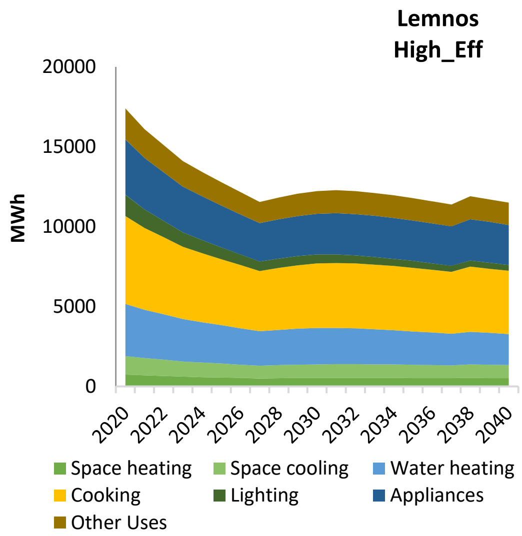
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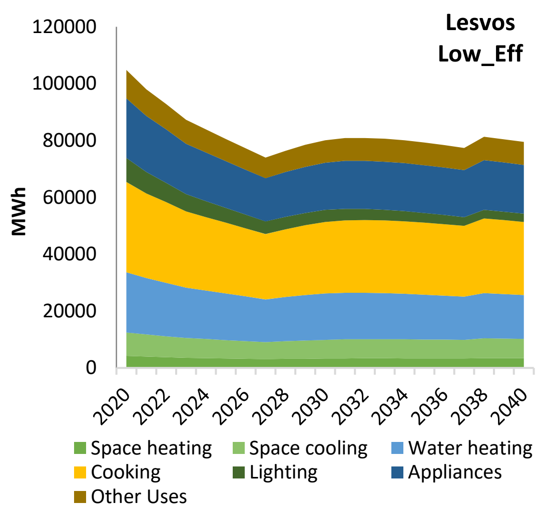
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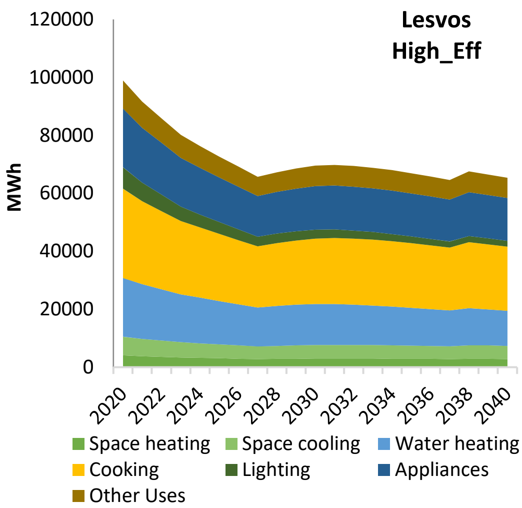
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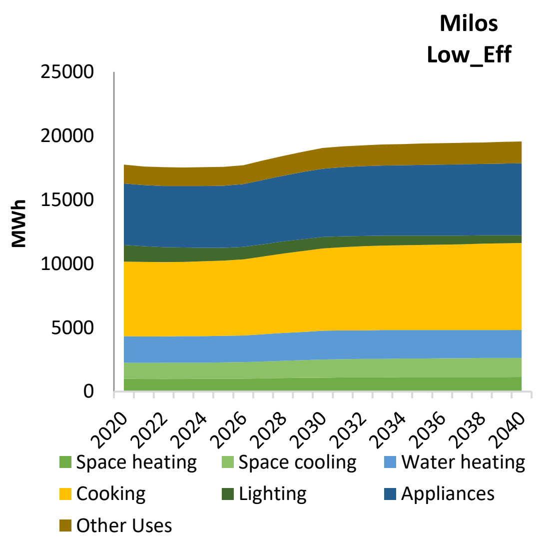
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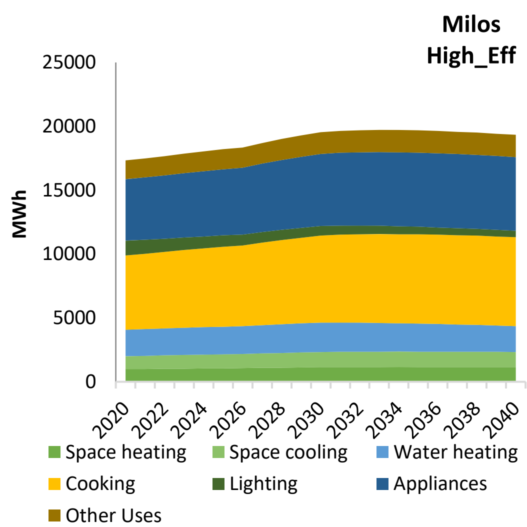
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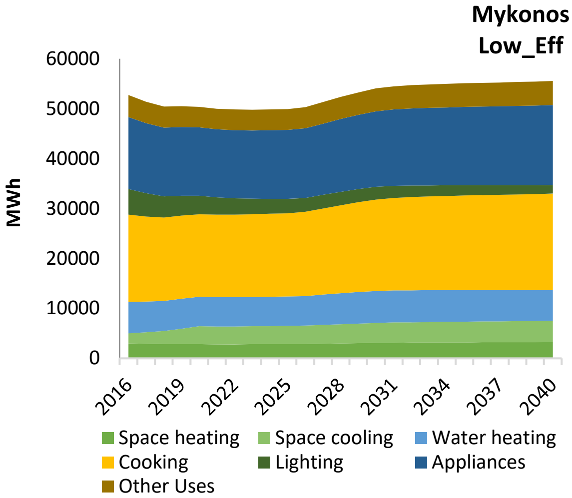
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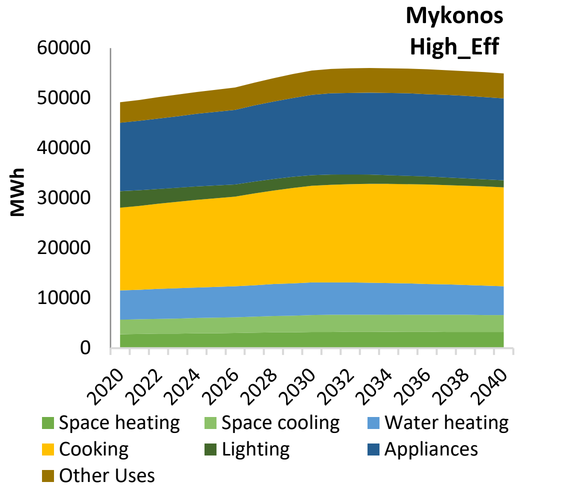
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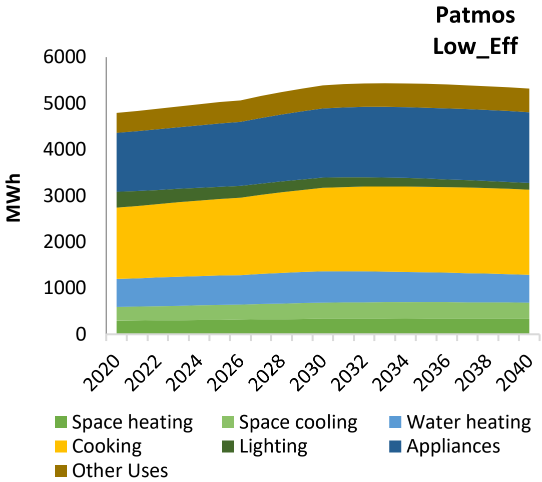
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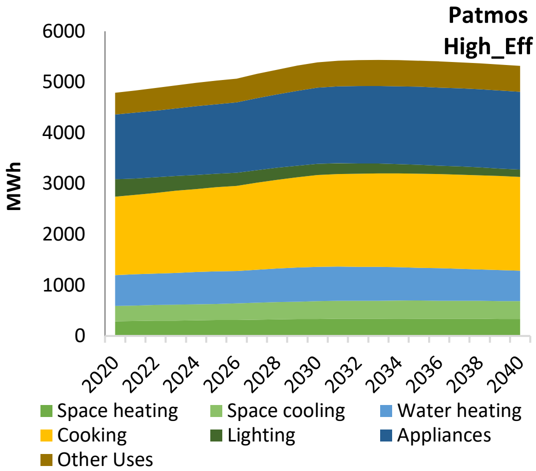
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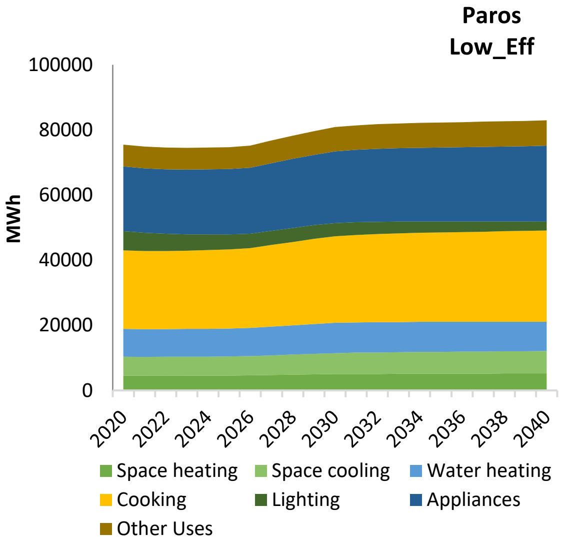
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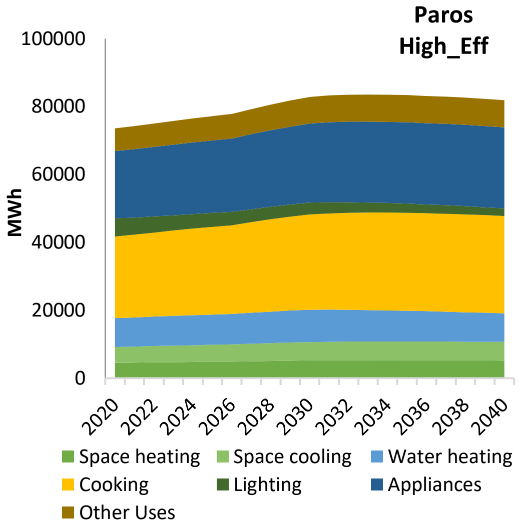
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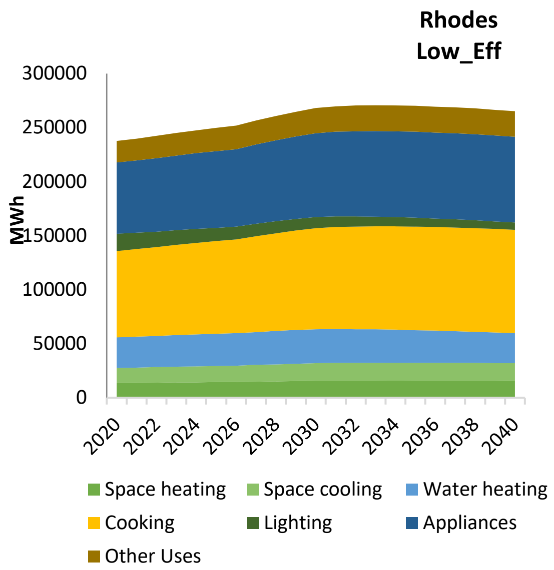
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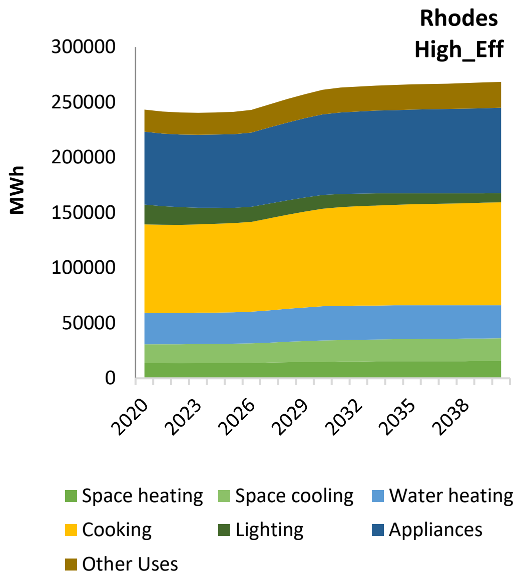
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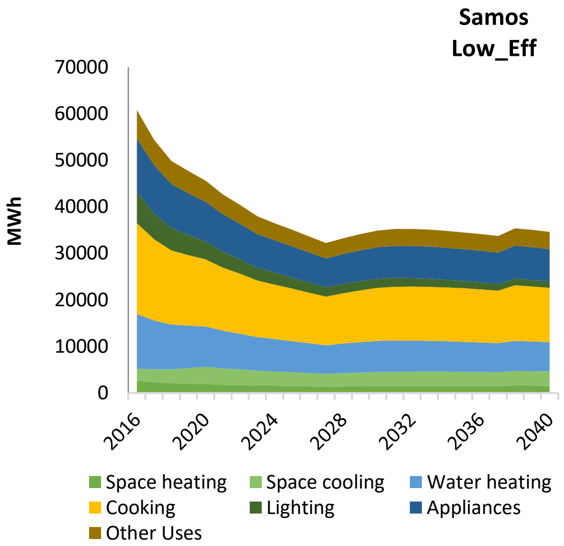
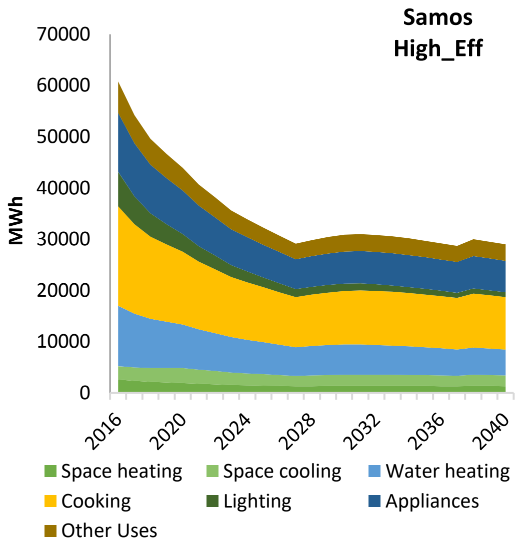
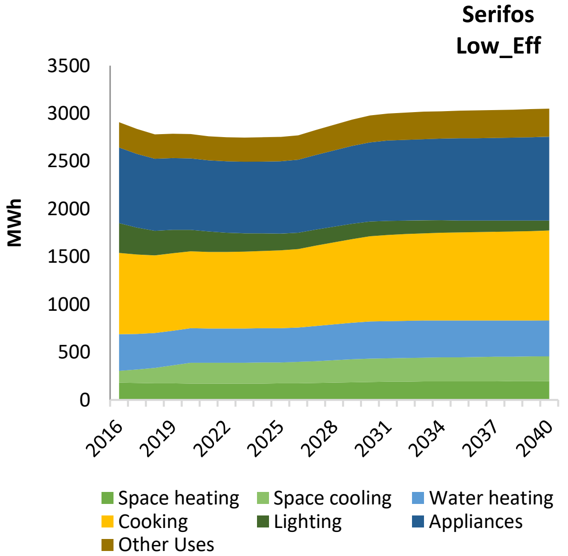
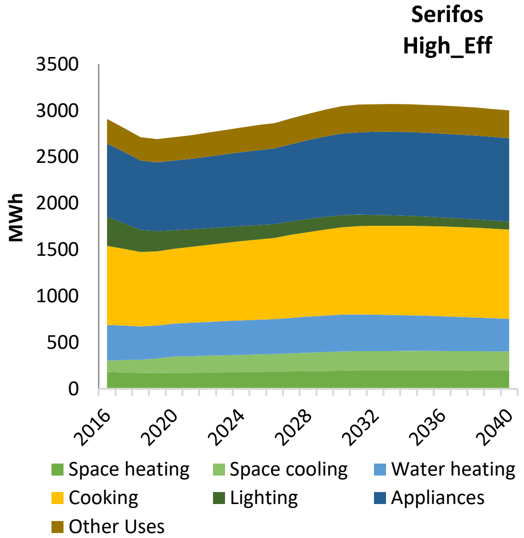
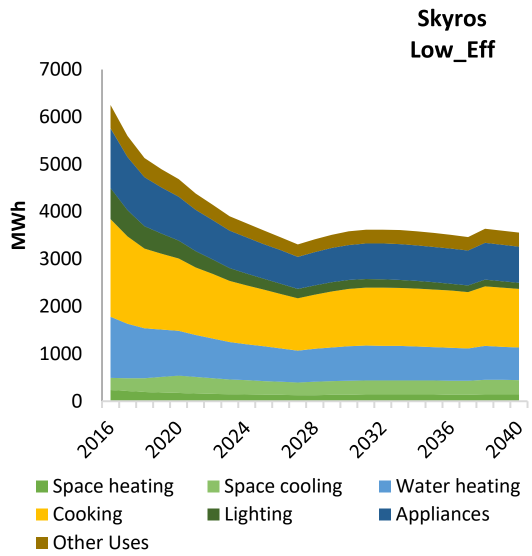
Appliances
Other Uses

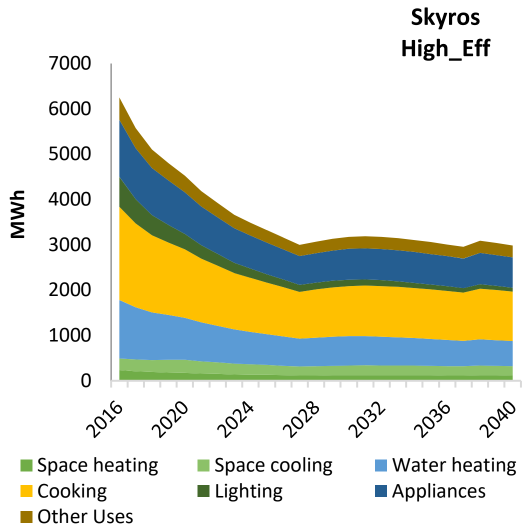

Samos
Low_Eff
MWh
70000
60000
50000
40000
30000
20000
10000
0
2016
2020
2024
2028
2032
2036
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses

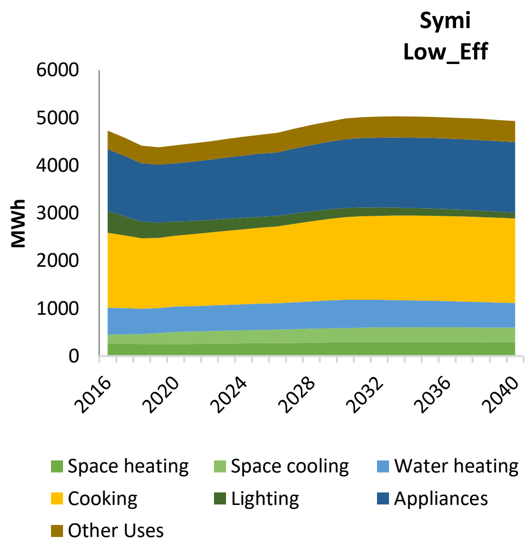

Samos
High_Eff
MWh
70000
60000
50000
40000
30000
20000
10000
0
2016
2020
2024
2028
2032
2036
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses

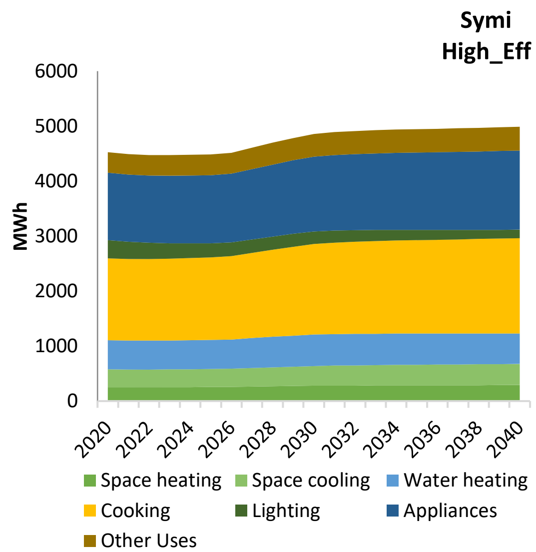

Serifos
Low_Eff
MWh
3500
3000
2500
2000
1500
1000
500
0
2016
2019
2022
2025
2028
2031
2034
2037
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses

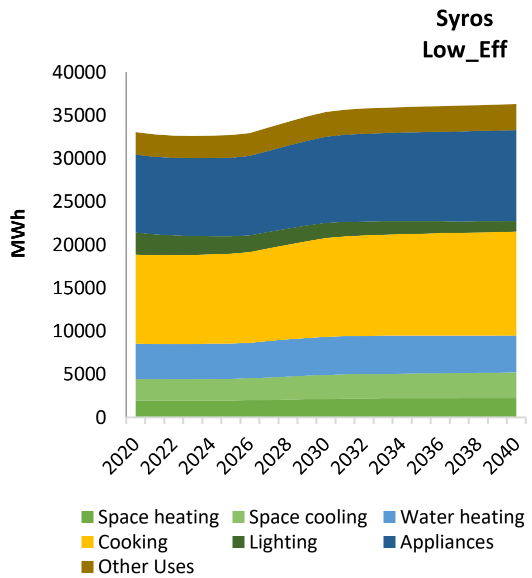

Serifos
High_Eff
MWh
3500
3000
2500
2000
1500
1000
500
0
2016
2020
2024
2028
2032
2036
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses

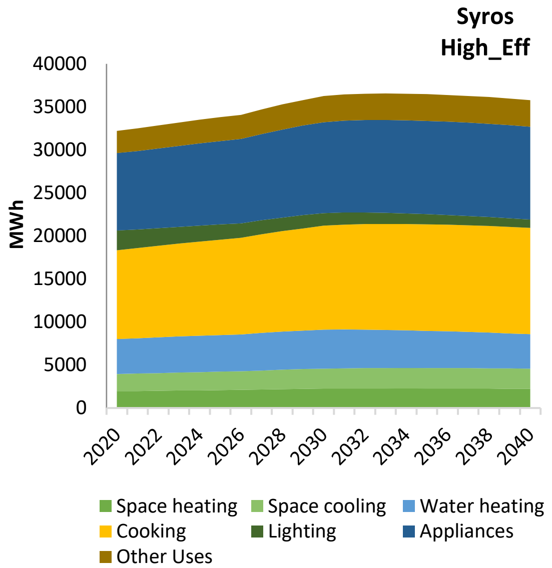

Skyros
Low_Eff
MWh
7000
6000
5000
4000
3000
2000
1000
0
2016
2020
2024
2028
2032
2036
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses

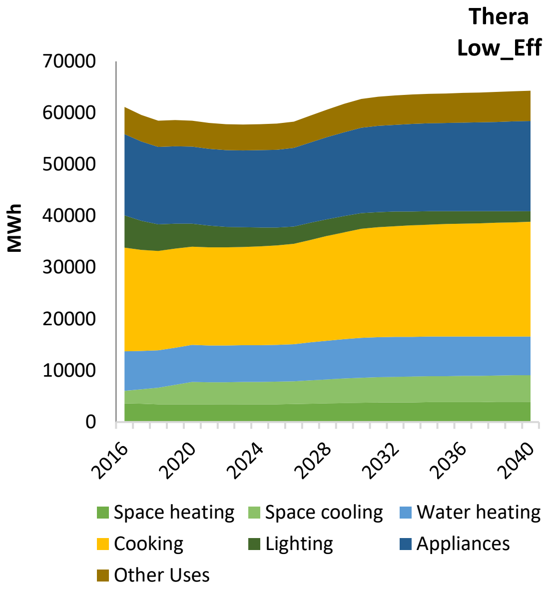

Skyros
High_Eff
MWh
7000
6000
5000
4000
3000
2000
1000
0
2016
2020
2024
2028
2032
2036
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses


Symi
Low_Eff
MWh
6000
5000
4000
3000
2000
1000
0
2016
2020
2024
2028
2032
2036
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses


Symi
High_Eff
MWh
6000
5000
4000
3000
2000
1000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses


Syros
Low_Eff
MWh
40000
35000
30000
25000
20000
15000
10000
5000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses


Syros
High_Eff
MWh
40000
35000
30000
25000
20000
15000
10000
5000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Cooking
Lighting
Appliances
Other Uses



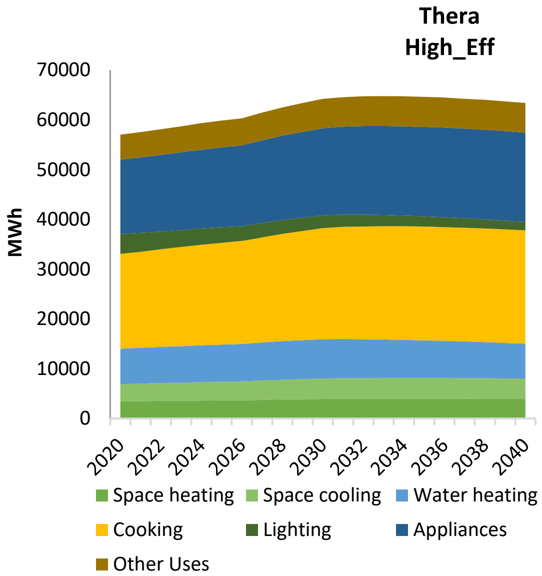
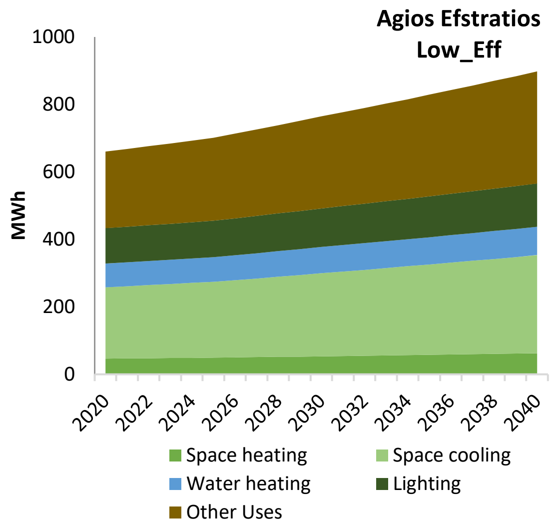
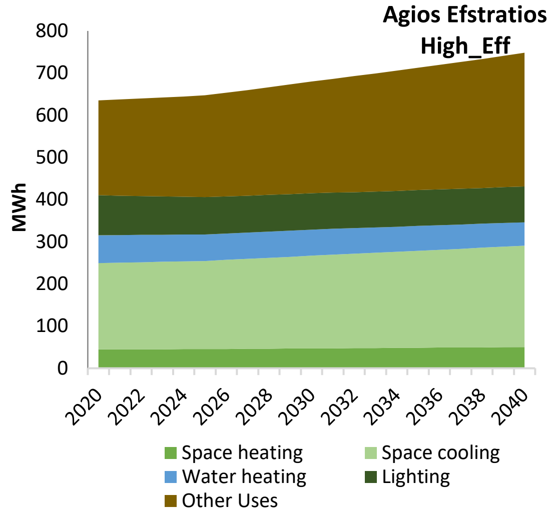
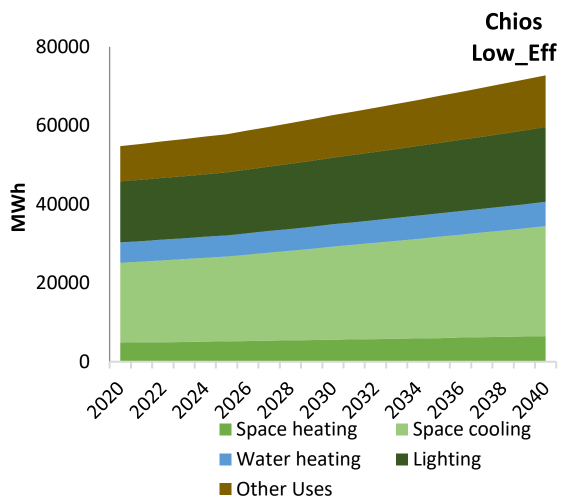


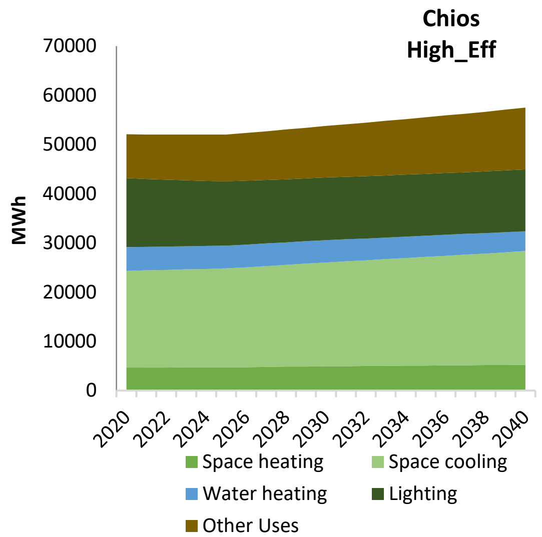
Figure I.a: Residential demand end-uses for Low_Eff and High_Eff scenarios on the Greek islands

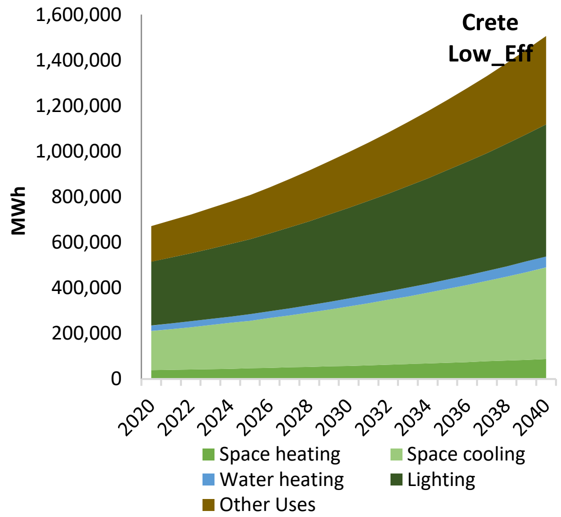
ANNEX I.b

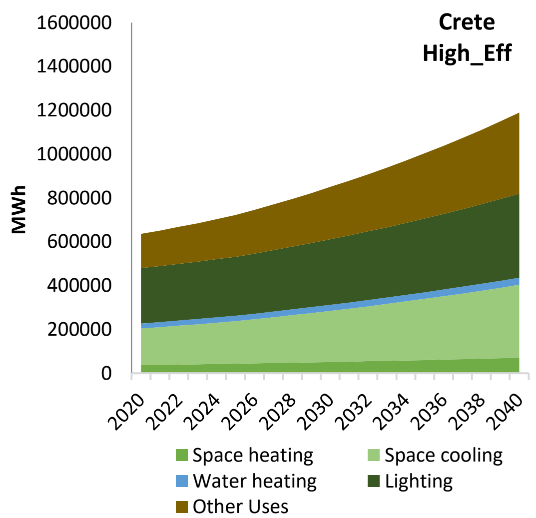

Agios Efstratios
Low_Eff
MWh
1000
800
600
400
200
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

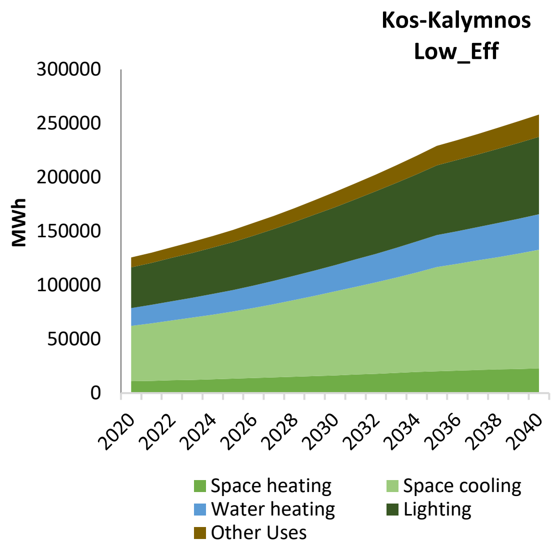

Agios Efstratios
High_Eff
MWh
800
700
600
500
400
300
200
100
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

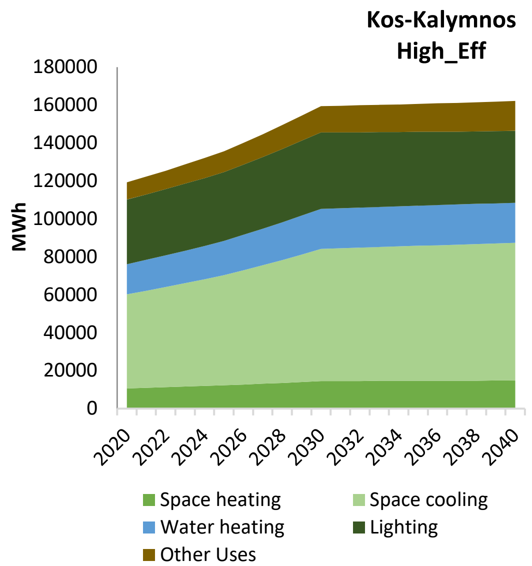

Chios
Low_Eff
MWh
80000
60000
40000
20000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

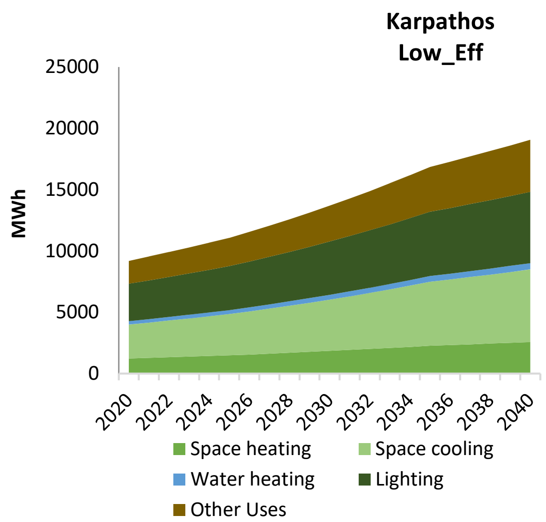

Chios
High_Eff
MWh
70000
60000
50000
40000
30000
20000
10000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

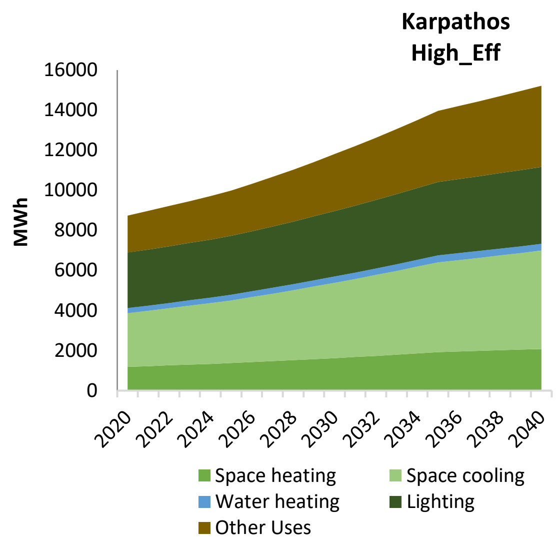

Crete
Low_Eff
MWh
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

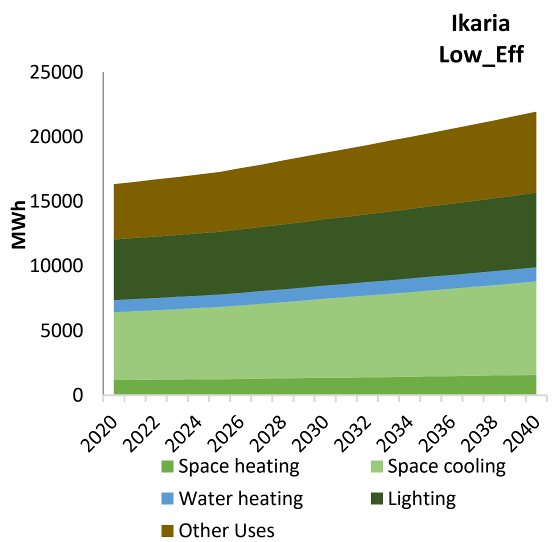

Crete
High_Eff
MWh
1600000
1400000
1200000
1000000
800000
600000
400000
200000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

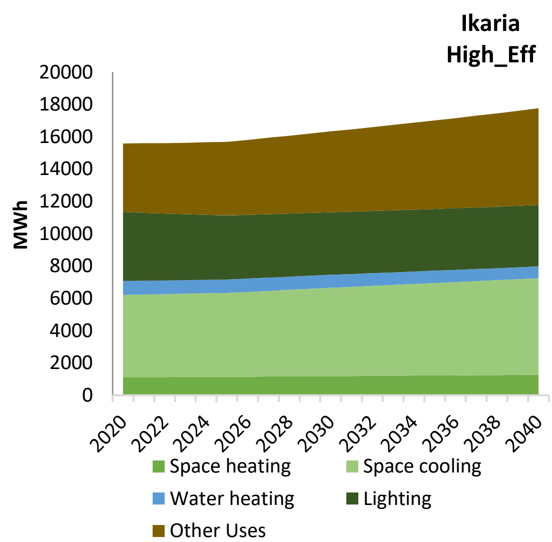

Kos-Kalymnos
Low_Eff
300000
250000
200000
150000
100000
50000
0
MWh
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Kos-Kalymnos
High_Eff
180000
160000
140000
120000
100000
80000
60000
40000
20000
0
MWh
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Karpathos
Low_Eff
25000
20000
15000
10000
5000
0
MWh
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Karpathos
High_Eff
16000
14000
12000
10000
8000
6000
4000
2000
0
MWh
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Ikaria
Low_Eff
25000
20000
15000
10000
5000
0
MWh
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Ikaria
High_Eff
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
MWh
2020
2022
2024
2026
2028
2030
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2034
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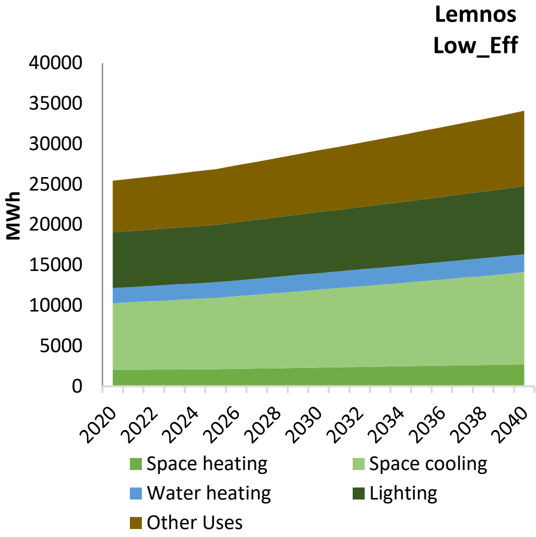
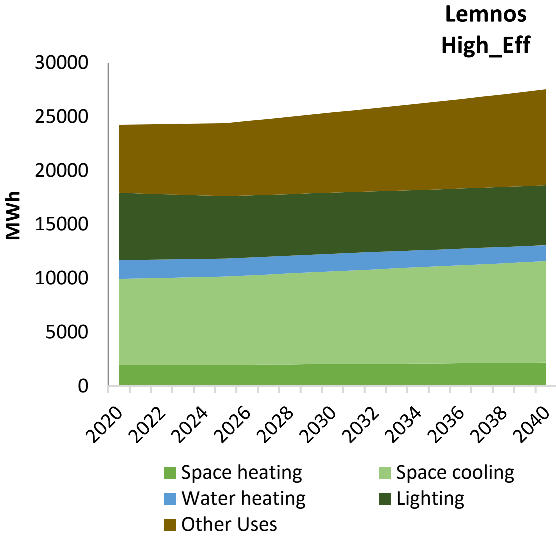
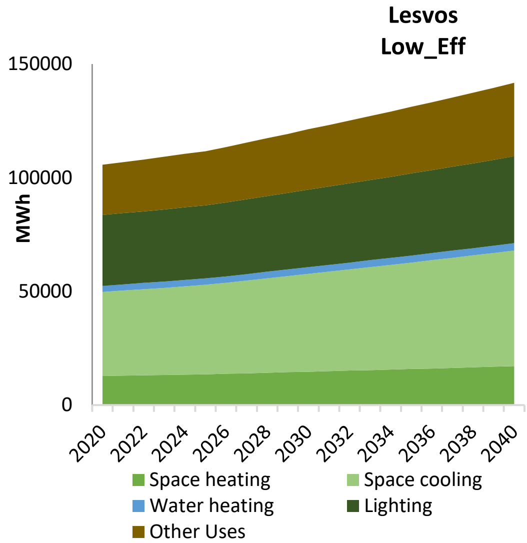
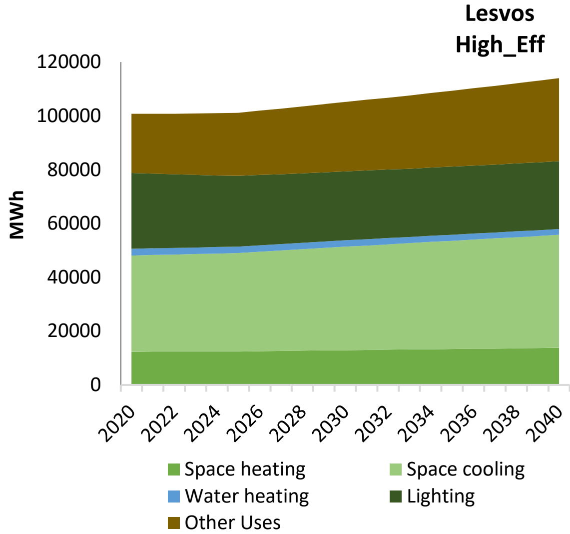
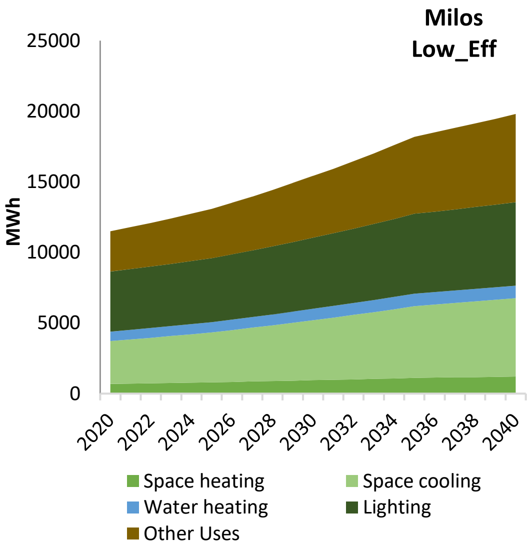
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

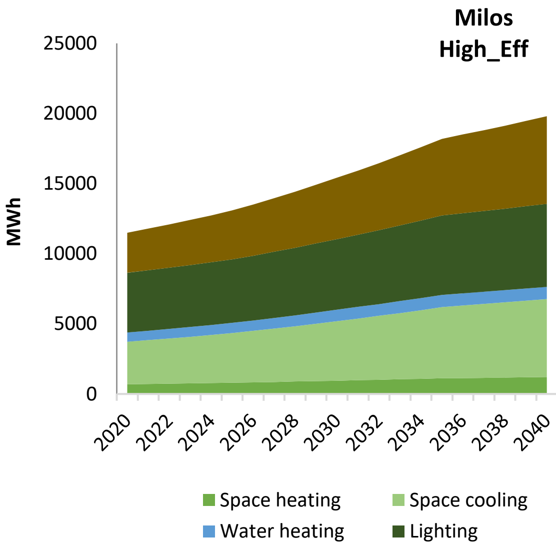

Lemnos
Low_Eff
MWh
40000
35000
30000
25000
20000
15000
10000
5000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

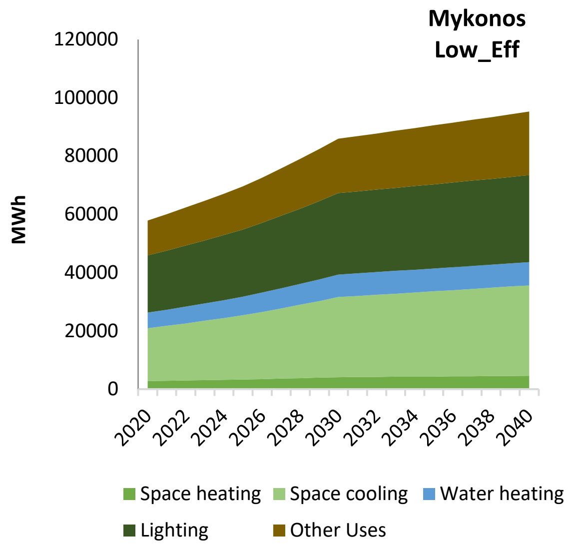

Lemnos
High_Eff
MWh
30000
25000
20000
15000
10000
5000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

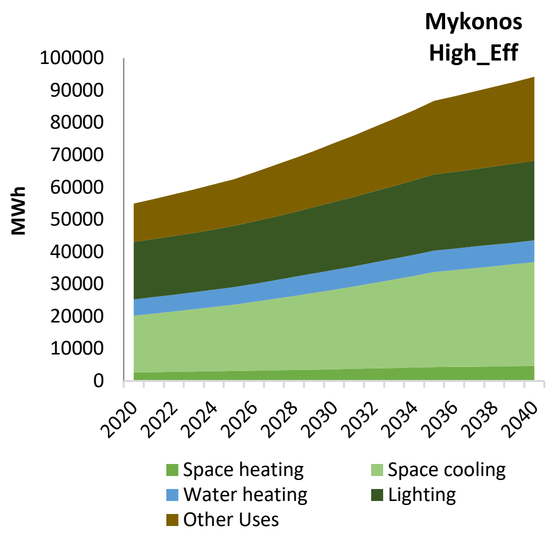

Lesvos
Low_Eff
MWh
150000
100000
50000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

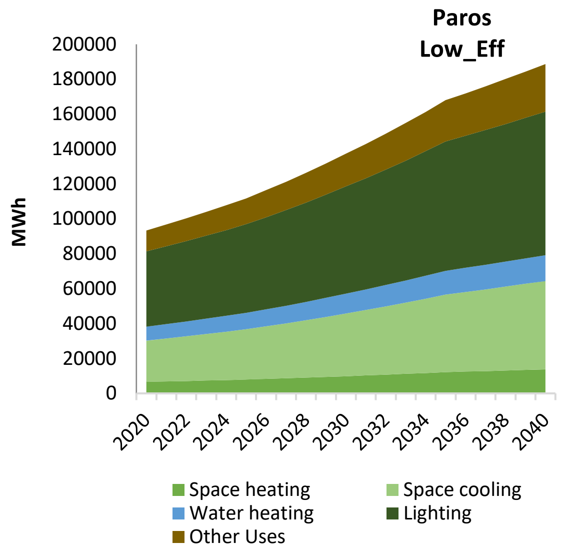

Lesvos
High_Eff
MWh
120000
100000
80000
60000
40000
20000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

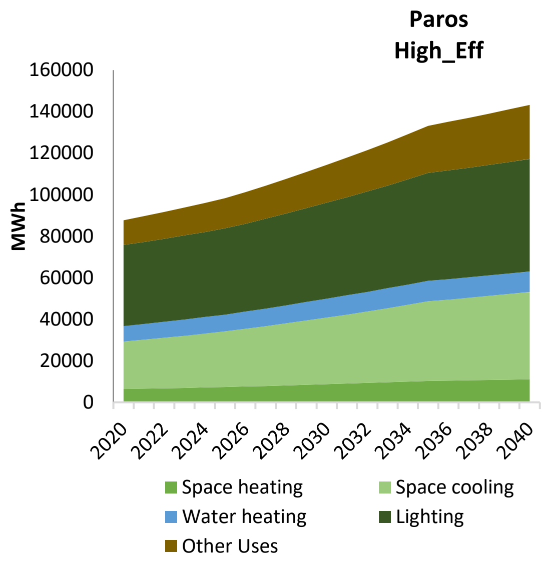

Milos
Low_Eff
MWh
25000
20000
15000
10000
5000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

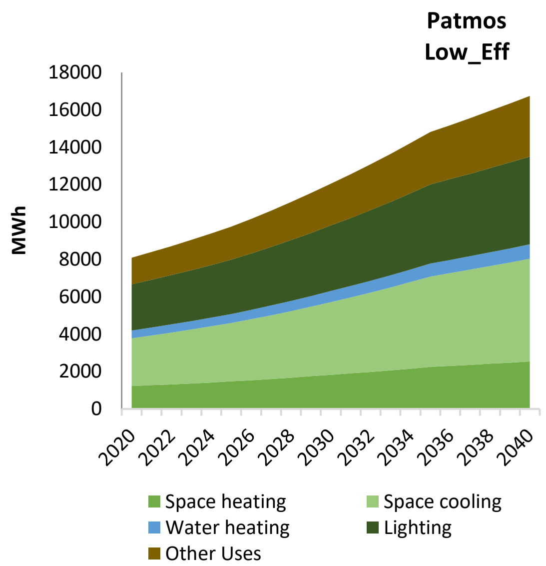

Milos
High_Eff
MWh
25000
20000
15000
10000
5000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting

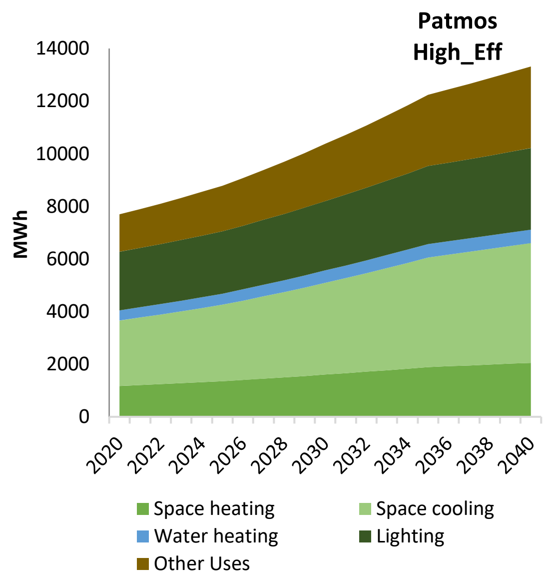

Mykonos
Low_Eff
MWh
120000
100000
80000
60000
40000
20000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

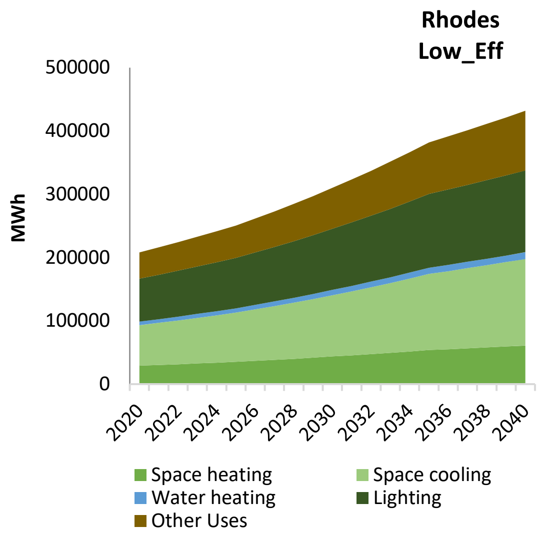

Mykonos
High_Eff
MWh
100000
90000
80000
70000
60000
50000
40000
30000
20000
10000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

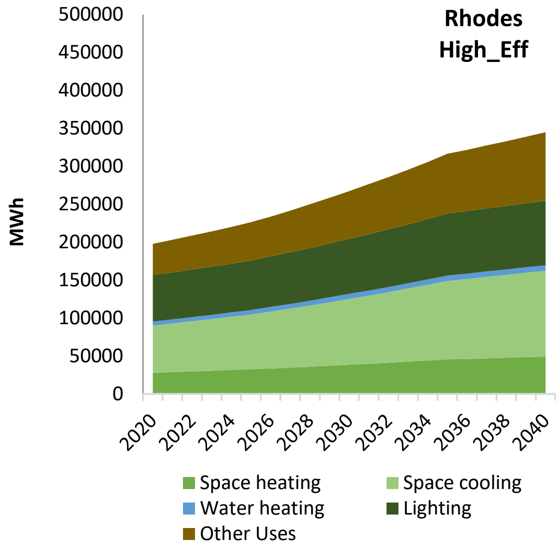

Paros
Low_Eff
MWh
200000
180000
160000
140000
120000
100000
80000
60000
40000
20000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

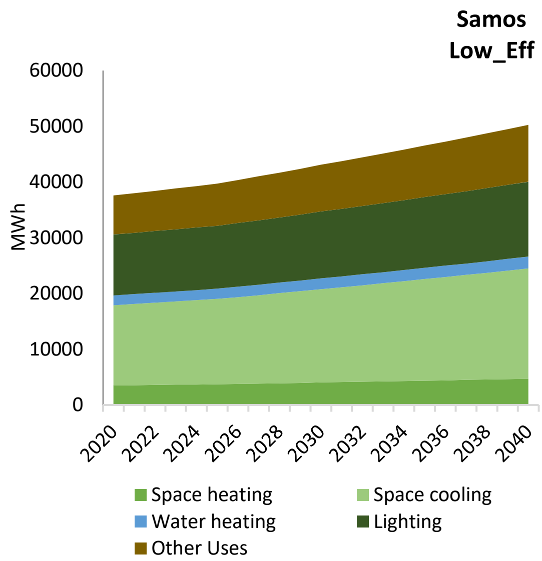

Paros
High_Eff
MWh
160000
140000
120000
100000
80000
60000
40000
20000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

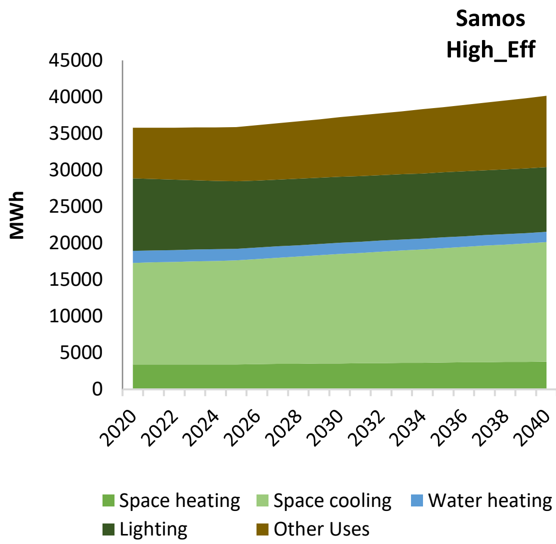

Patmos
Low_Eff
MWh
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

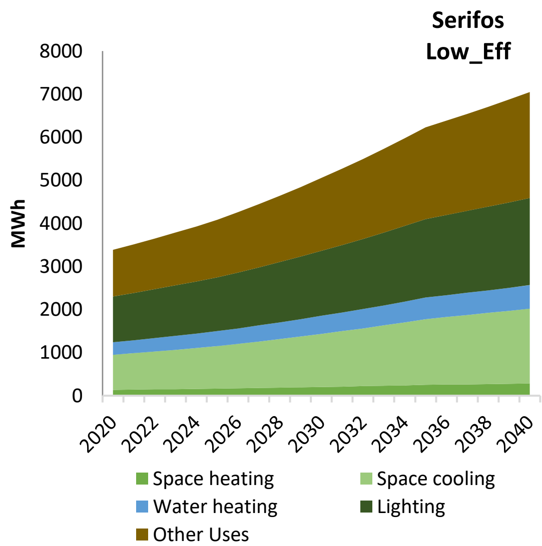

Patmos
High_Eff
MWh
14000
12000
10000
8000
6000
4000
2000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

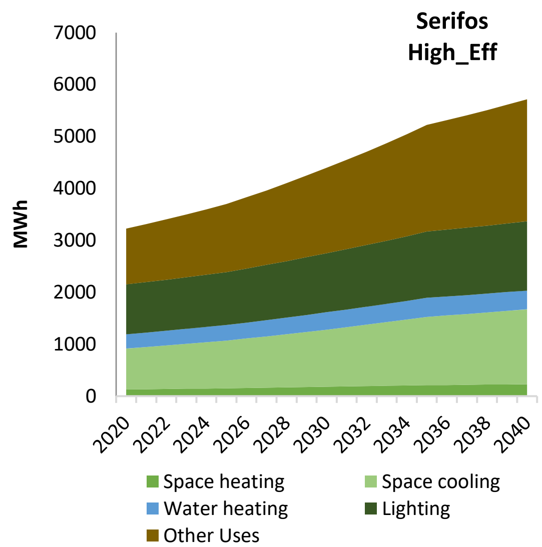

Rhodes
Low_Eff
MWh
500000
400000
300000
200000
100000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

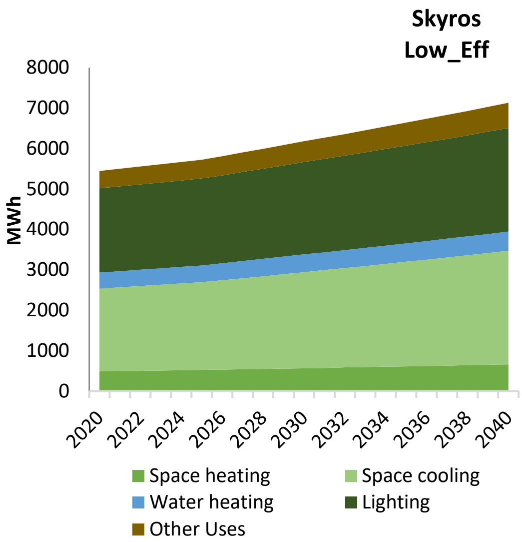

Rhodes
High_Eff
MWh
500000
450000
400000
350000
300000
250000
200000
150000
100000
50000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Samos
Low_Eff
MWh
60000
50000
40000
30000
20000
10000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

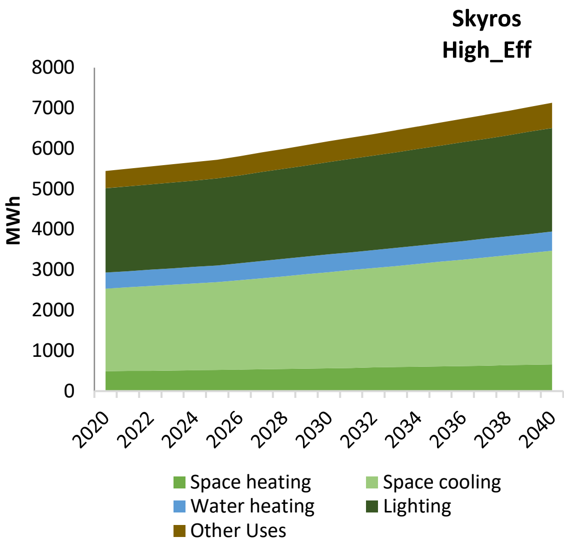

Samos
High_Eff
MWh
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Serifos
Low_Eff
MWh
8000
7000
6000
5000
4000
3000
2000
1000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

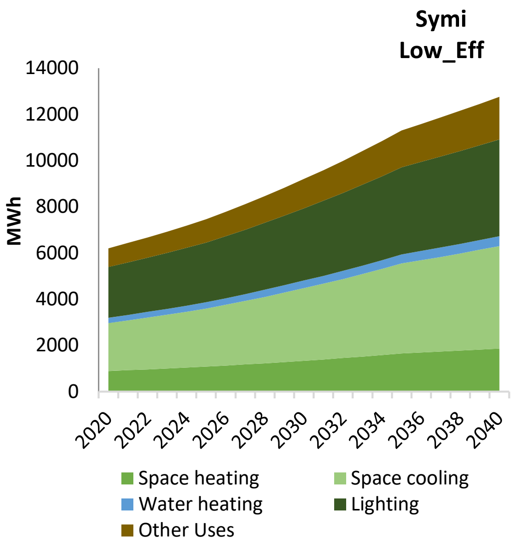

Serifos
High_Eff
MWh
7000
6000
5000
4000
3000
2000
1000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses



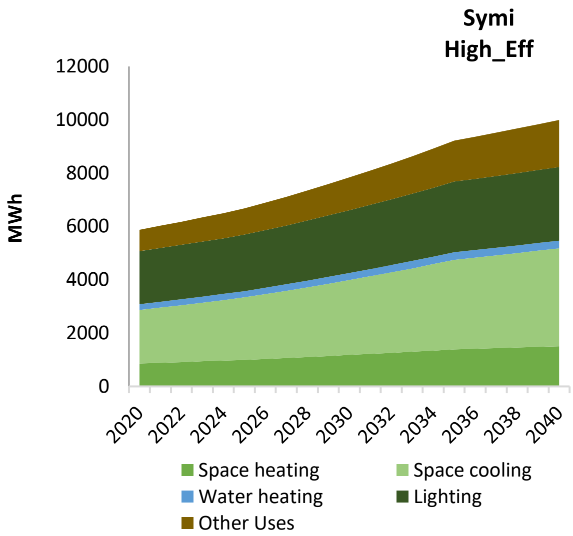
Skyros
Low_Eff
MWh
8000
7000
6000
5000
4000
3000
2000
1000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses



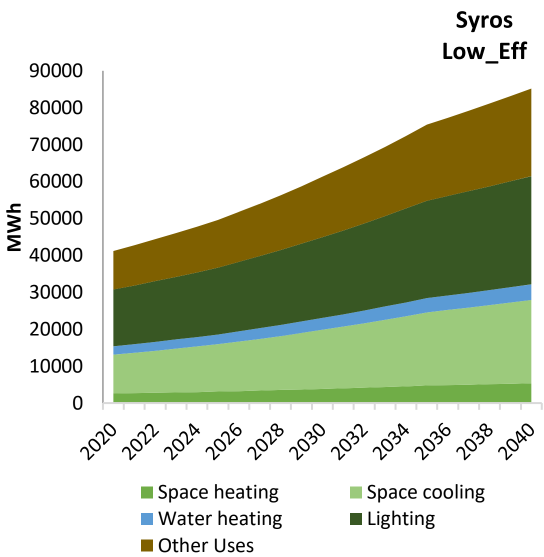
Skyros
High_Eff
MWh
8000
7000
6000
5000
4000
3000
2000
1000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses



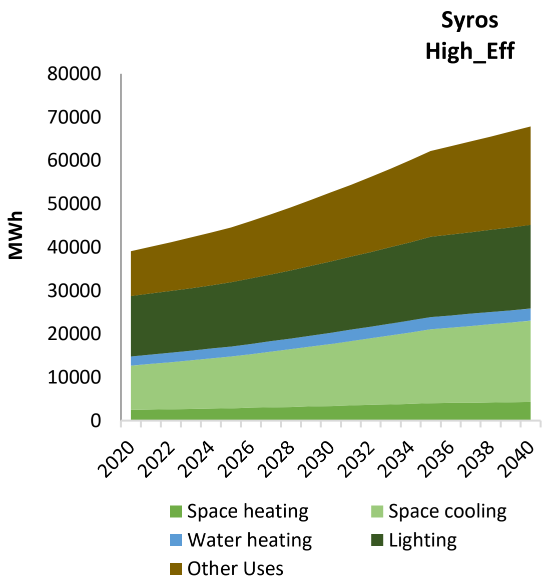
Symi
Low_Eff
MWh
14000
12000
10000
8000
6000
4000
2000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses



Symi
High_Eff
MWh
12000
10000
8000
6000
4000
2000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses



Syros
Low_Eff
MWh
90000
80000
70000
60000
50000
40000
30000
20000
10000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses



Syros
High_Eff
MWh
80000
70000
60000
50000
40000
30000
20000
10000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

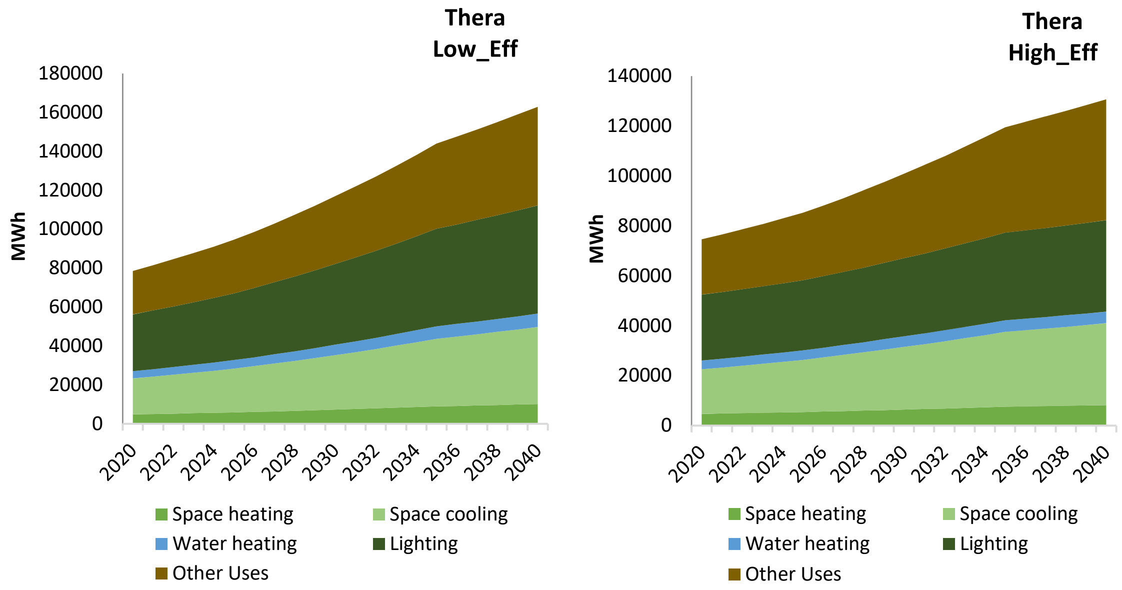
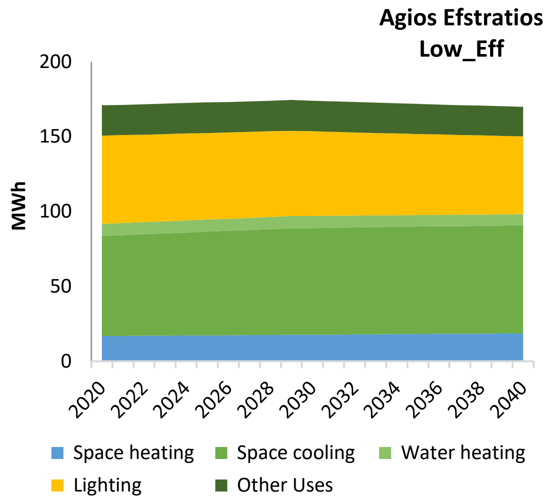
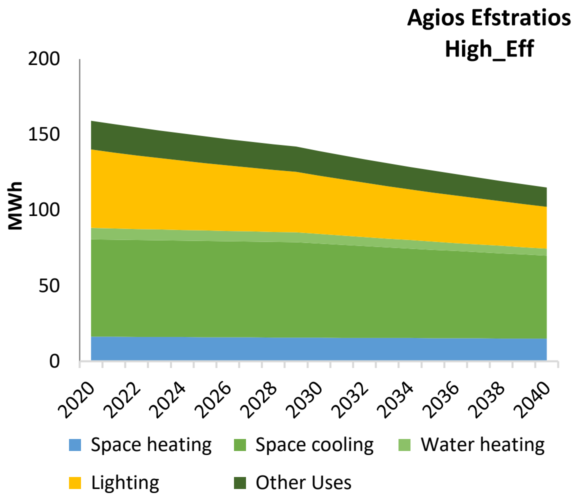
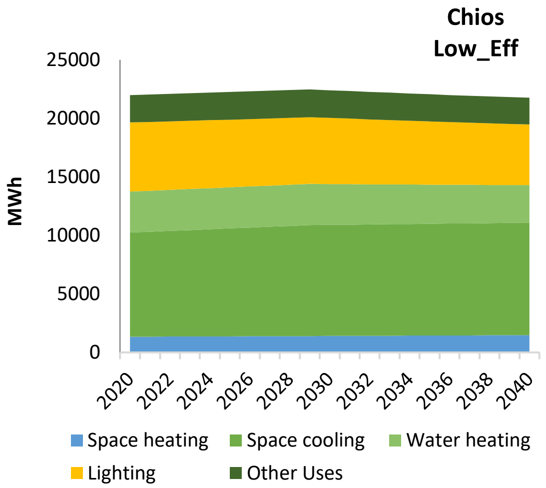


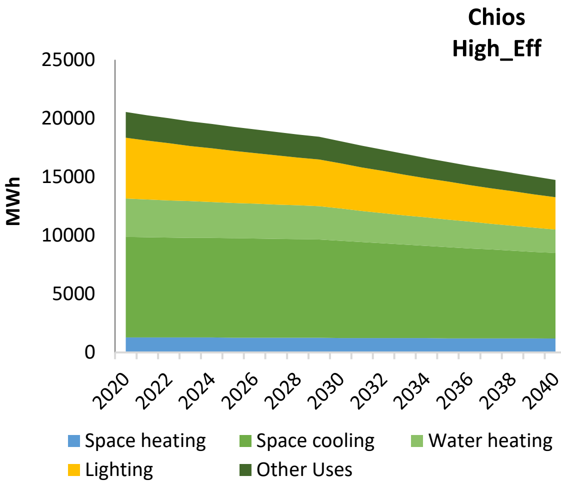
Figure I.b: Commercial demand end-uses for Low_Eff and High_Eff scenarios on the Greek islands

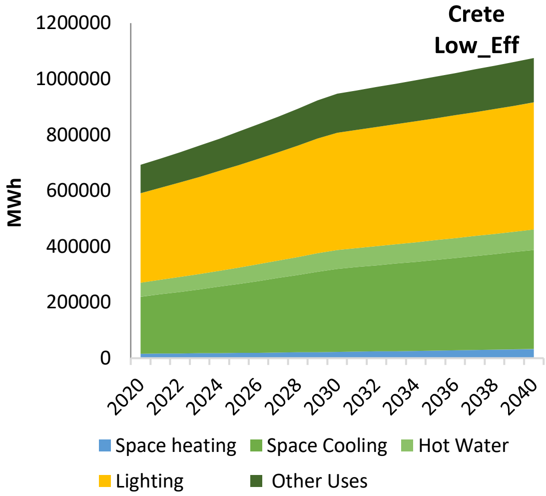
ANNEX I.c

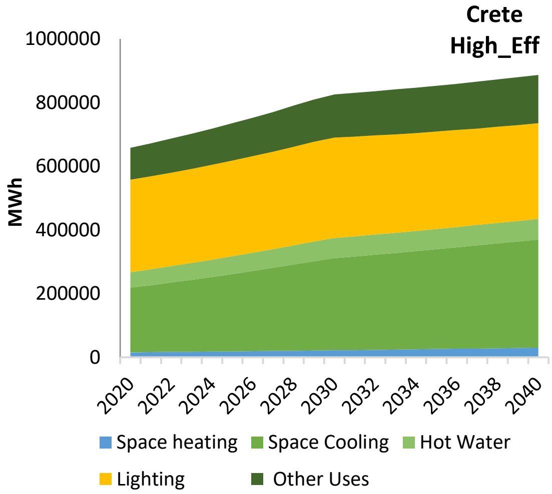

Agios Efstratios
Low_Eff
MWh
200
150
100
50
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

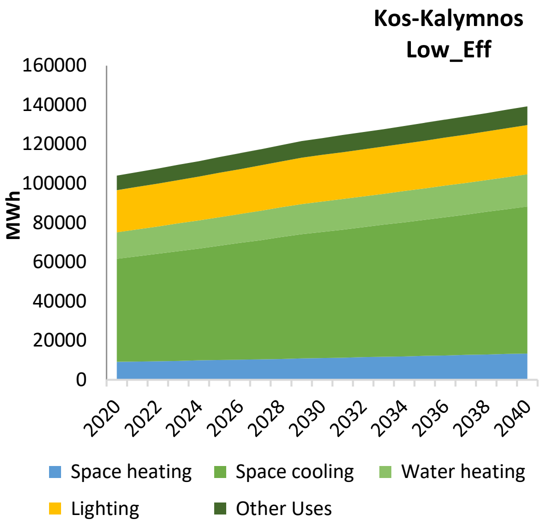

Agios Efstratios
High_Eff
MWh
200
150
100
50
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

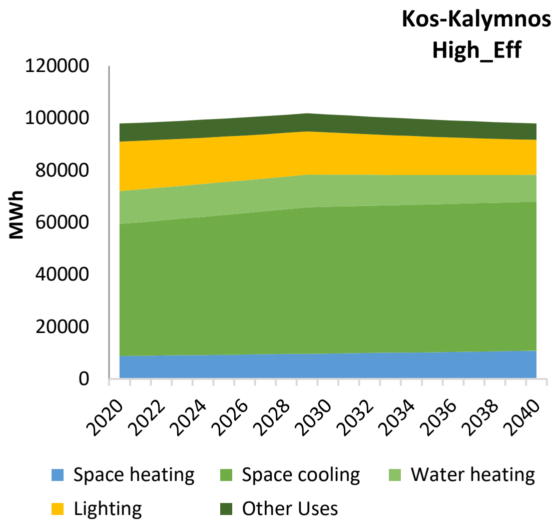

Chios
Low_Eff
MWh
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

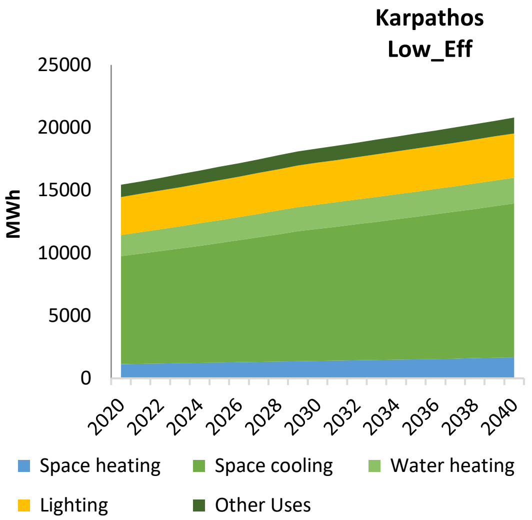

Chios
High_Eff
MWh
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

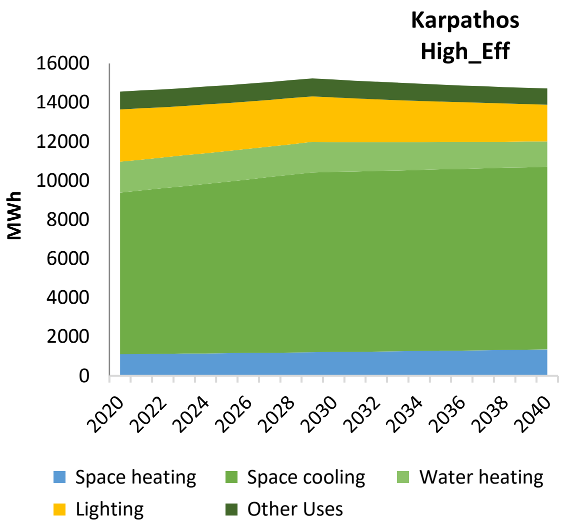

Crete
Low_Eff
MWh
1200000
1000000
800000
600000
400000
200000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space Cooling
Hot Water
Lighting
Other Uses

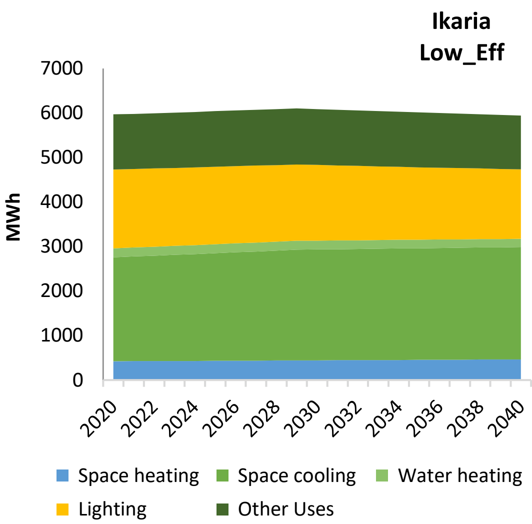

Crete
High_Eff
MWh
1000000
800000
600000
400000
200000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space Cooling
Hot Water
Lighting
Other Uses

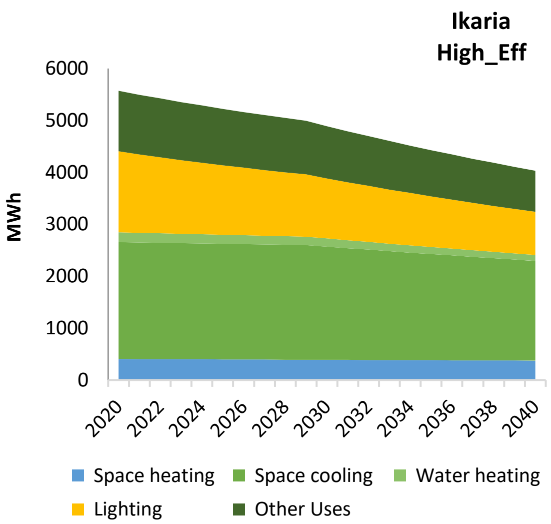

Kos-Kalymnos
Low_Eff
MWh
160000
140000
120000
100000
80000
60000
40000
20000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

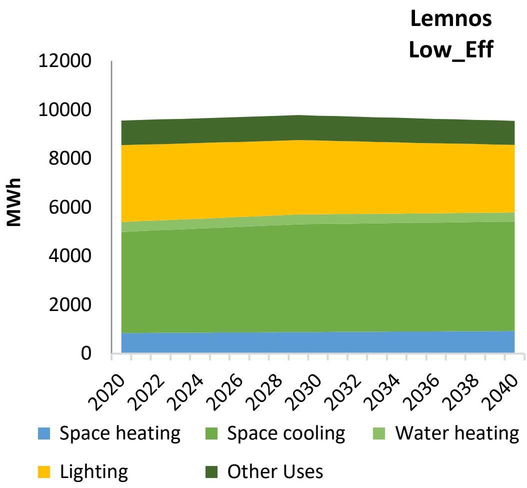

Kos-Kalymnos
High_Eff
MWh
120000
100000
80000
60000
40000
20000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

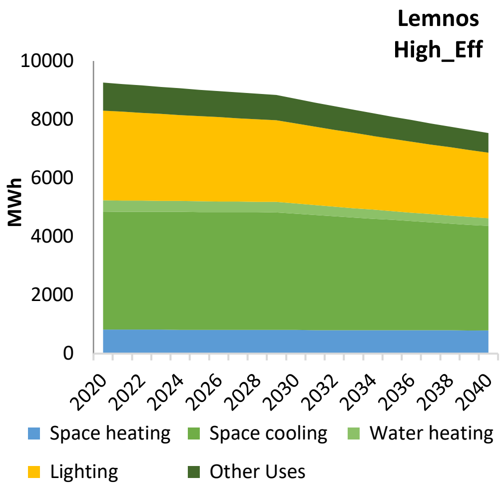

Karpathos
Low_Eff
MWh
25000
20000
15000
10000
5000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

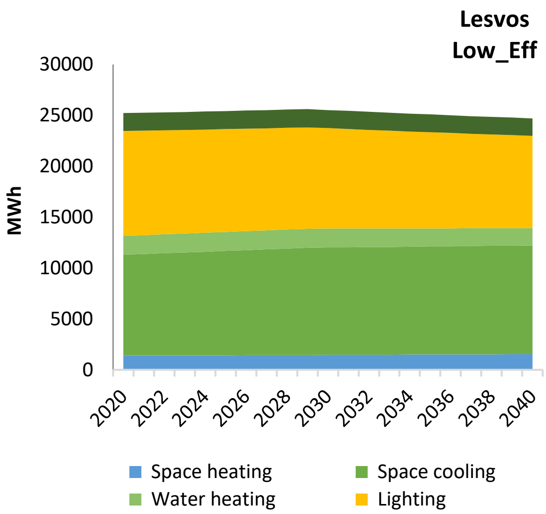

Karpathos
High_Eff
MWh
16000
14000
12000
10000
8000
6000
4000
2000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

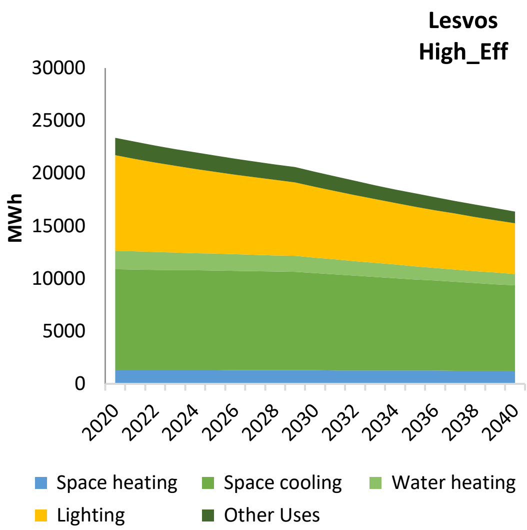

Ikaria
Low_Eff
MWh
7000
6000
5000
4000
3000
2000
1000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

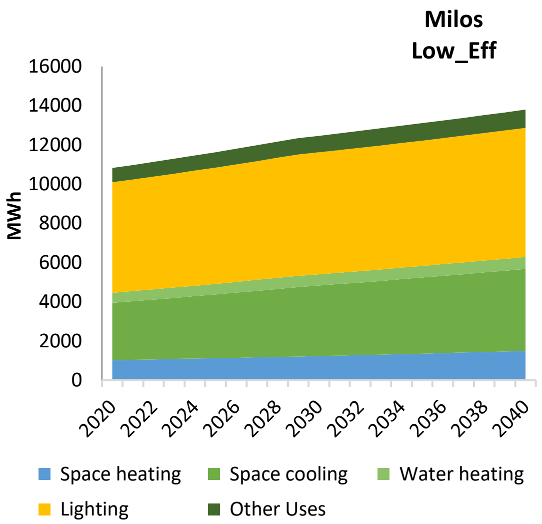

Ikaria
High_Eff
MWh
6000
5000
4000
3000
2000
1000
0
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

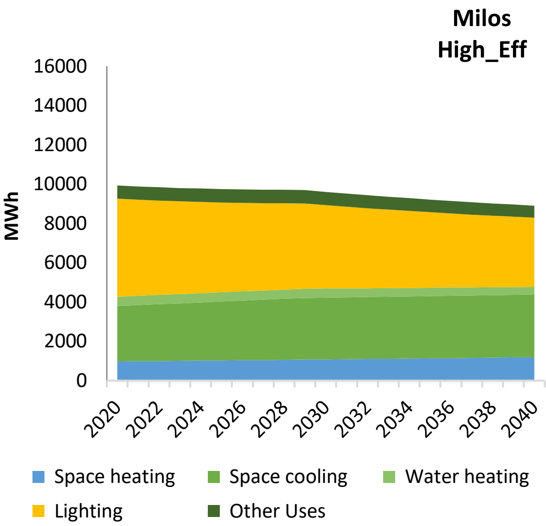

Lemnos
Low_Eff
MWh
12000
10000
8000
6000
4000
2000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

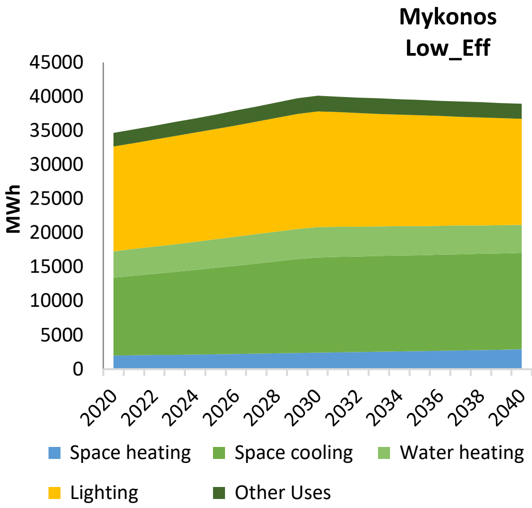

Lemnos
High_Eff
MWh
10000
8000
6000
4000
2000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

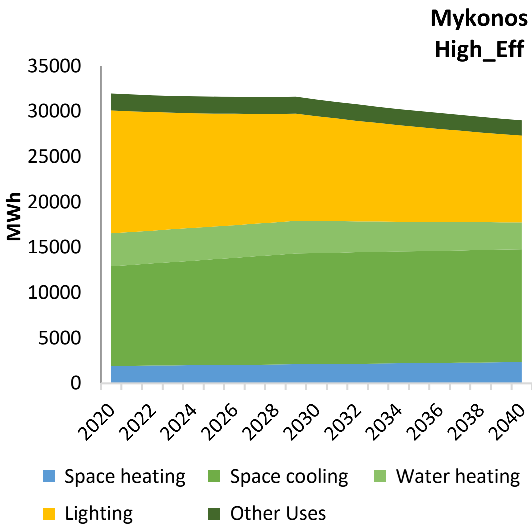

Lesvos
Low_Eff
MWh
30000
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting

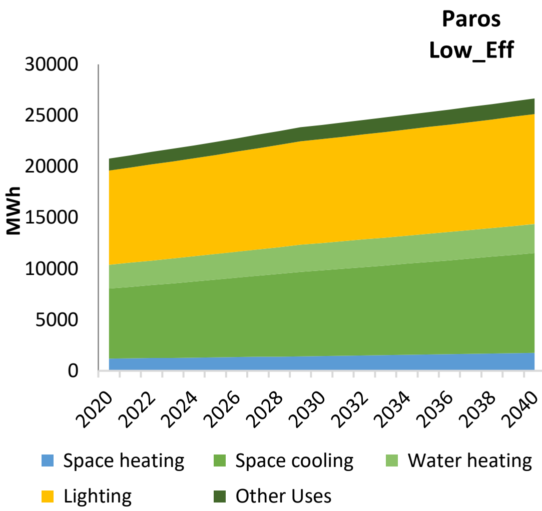

Lesvos
High_Eff
MWh
30000
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

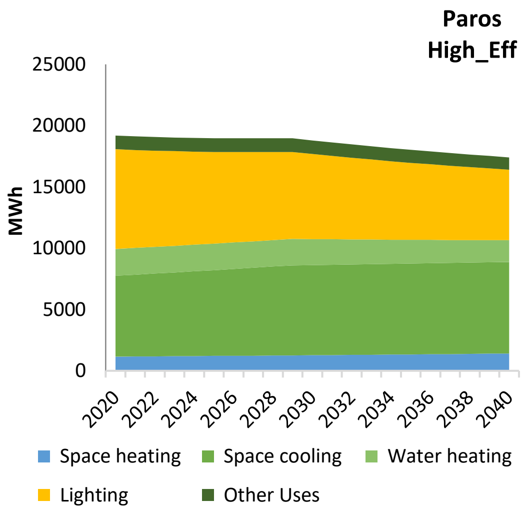

Milos
Low_Eff
MWh
16000
14000
12000
10000
8000
6000
4000
2000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

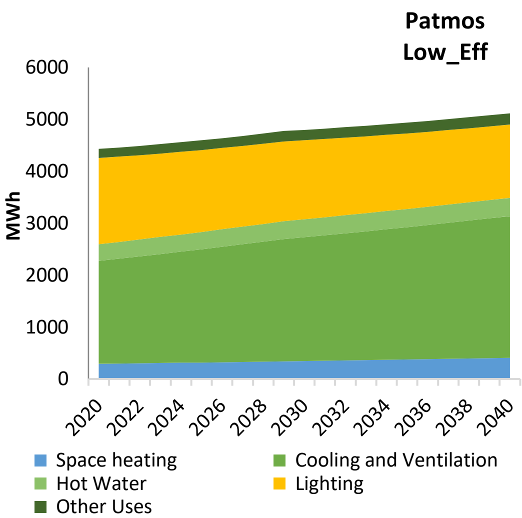

Milos
High_Eff
MWh
16000
14000
12000
10000
8000
6000
4000
2000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

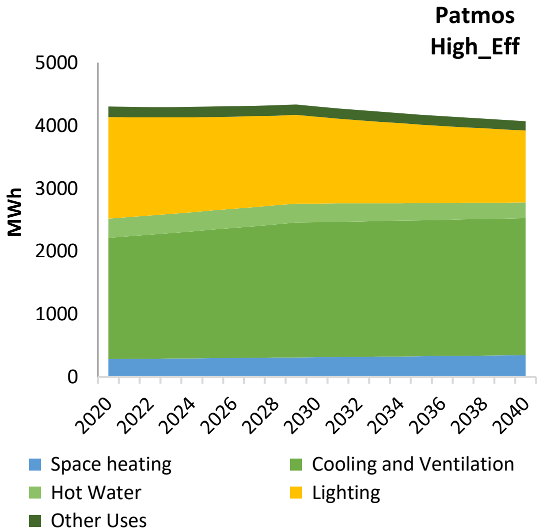

Mykonos
Low_Eff
MWh
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

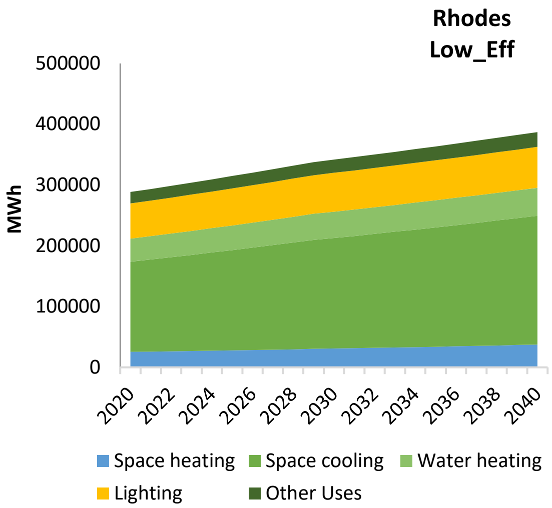

Mykonos
High_Eff
MWh
35000
30000
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

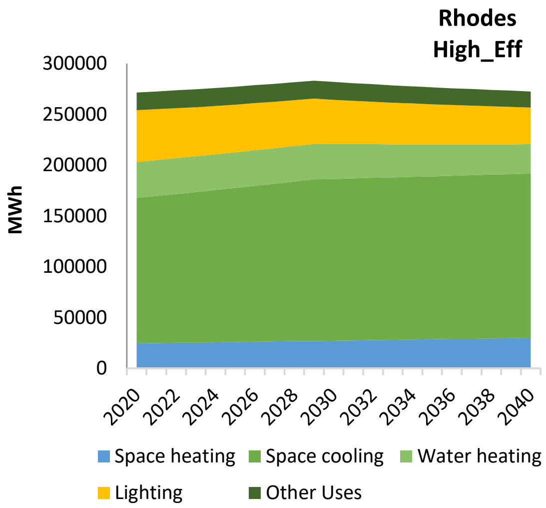

Paros
Low_Eff
MWh
30000
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

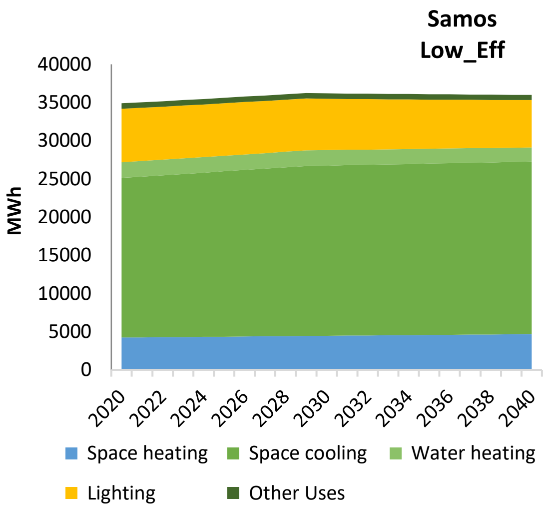

Paros
High_Eff
MWh
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

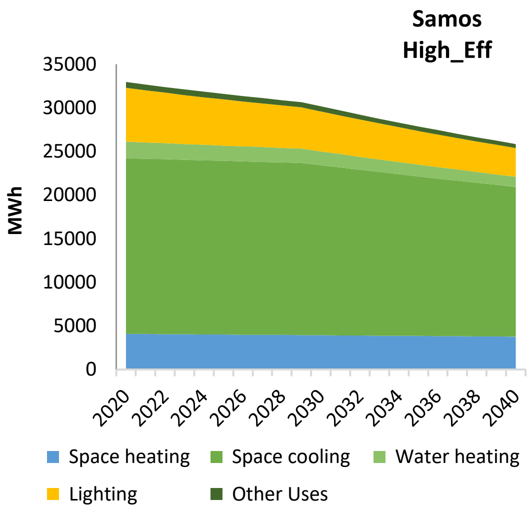

Patmos
Low_Eff
MWh
6000
5000
4000
3000
2000
1000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Cooling and Ventilation
Hot Water
Lighting
Other Uses

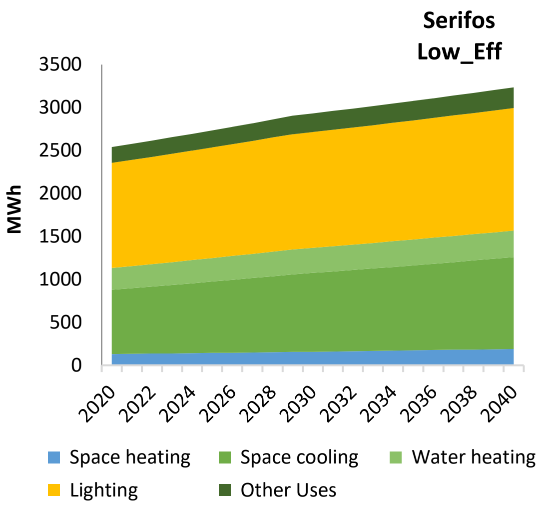

Patmos
High_Eff
MWh
5000
4000
3000
2000
1000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Cooling and Ventilation
Hot Water
Lighting
Other Uses

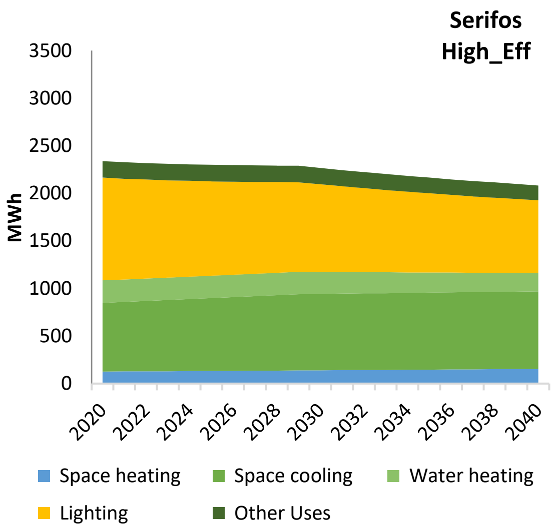

Rhodes
Low_Eff
MWh
500000
400000
300000
200000
100000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

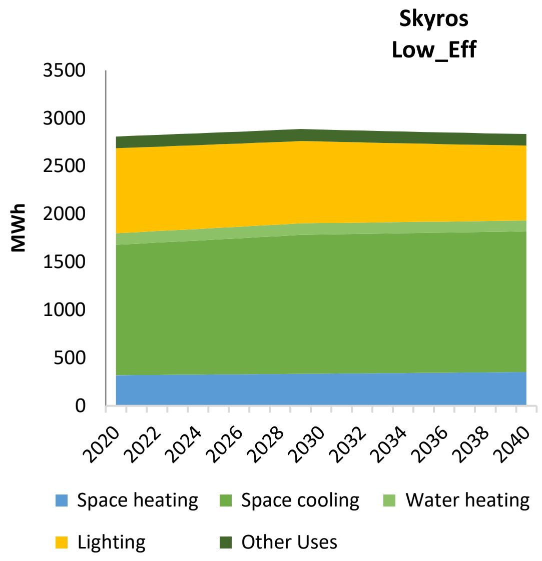

Rhodes
High_Eff
MWh
300000
250000
200000
150000
100000
50000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

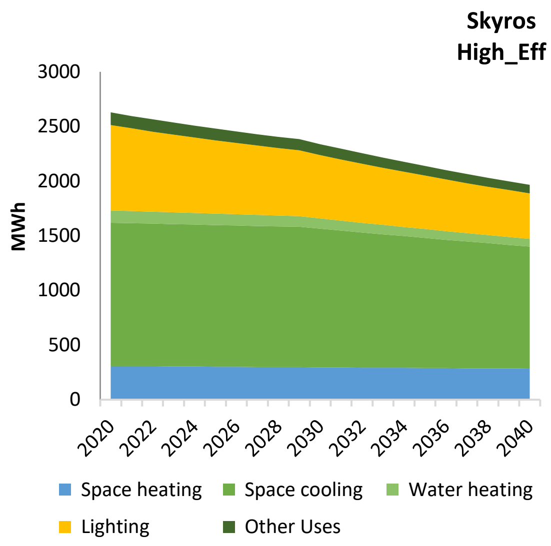

Samos
Low_Eff
MWh
40000
35000
30000
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

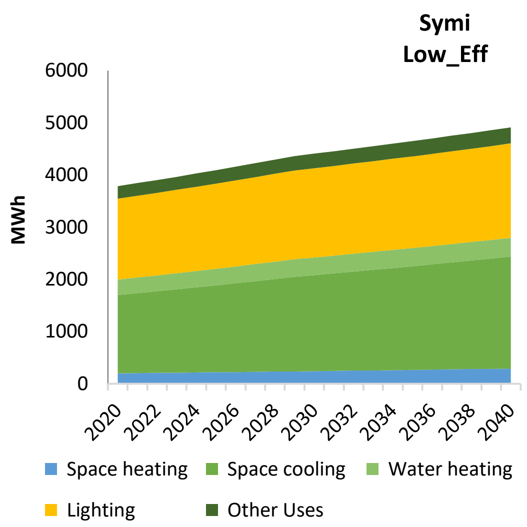

Samos
High_Eff
MWh
35000
30000
25000
20000
15000
10000
5000
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

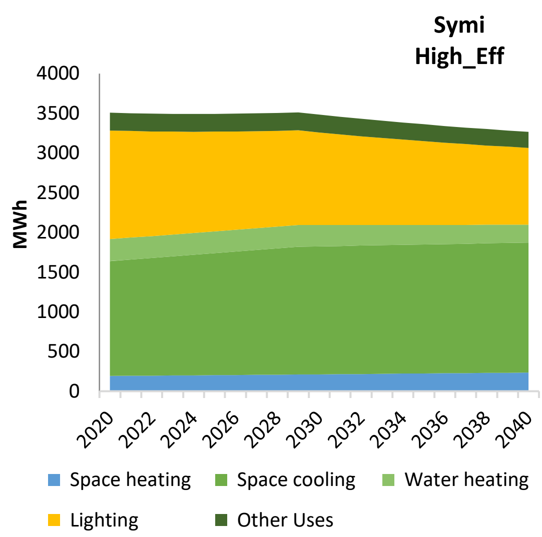

Serifos
Low_Eff
MWh
3500
3000
2500
2000
1500
1000
500
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

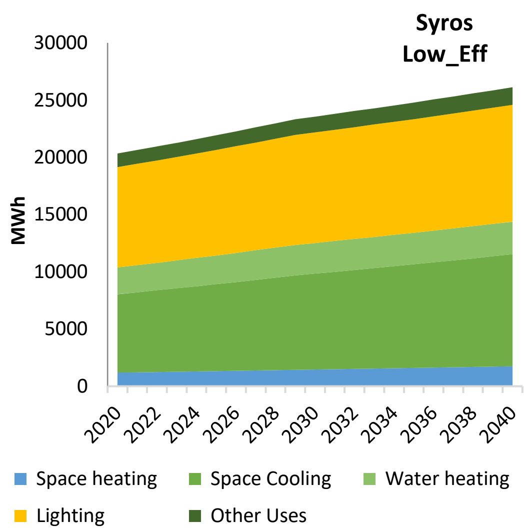

Serifos
High_Eff
MWh
3500
3000
2500
2000
1500
1000
500
0
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

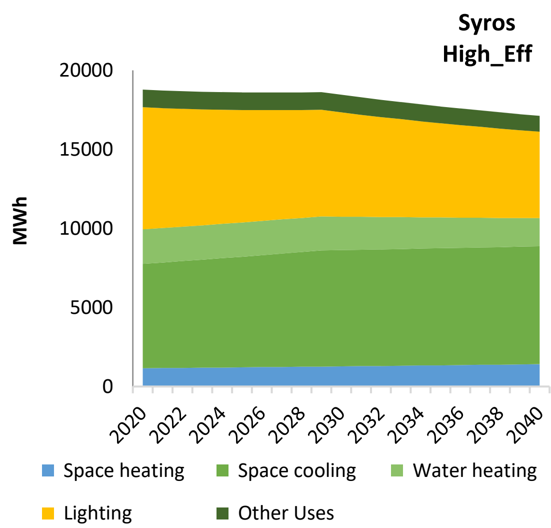

Skyros
Low_Eff
3500
3000
2500
2000
1500
1000
500
0
MWh
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Skyros
High_Eff
3000
2500
2000
1500
1000
500
0
MWh
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Symi
Low_Eff
6000
5000
4000
3000
2000
1000
0
MWh
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Symi
High_Eff
4000
3500
3000
2500
2000
1500
1000
500
0
MWh
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses


Syros
Low_Eff
30000
25000
20000
15000
10000
5000
0
MWh
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space Cooling
Water heating
Lighting
Other Uses


Syros
High_Eff
20000
15000
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MWh
2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Space heating
Space cooling
Water heating
Lighting
Other Uses

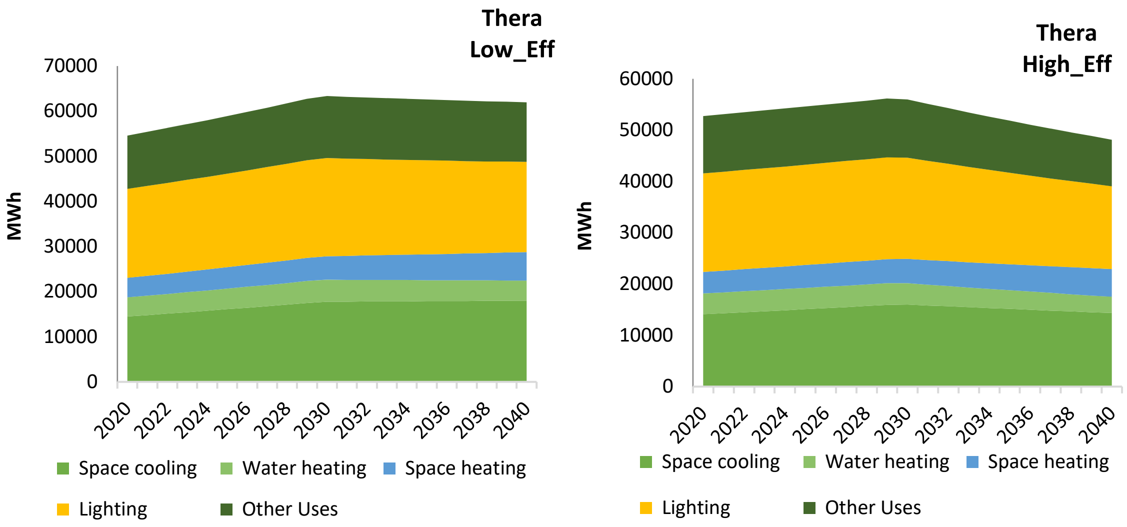

Figure I.c Tourism demand end-uses for Low_Eff and High_Eff scenarios on the Greek islands

ANNEX II.a

Table II.a Thermal power generators on the NIIs (2016)

Power Generators Units											
NII System	**Power Station**	**Unit**	**Unit Type**	**Fuel**	**Capacity Gross (MW)**	**Capacity Net (MW)**	**Technical Minimum (MW)**	**Commission Year**	**Decommission**	**Maint, Rate (%)**	**FOR (%)**
Crete	**Atherinolakkos Power Station**	FOSTER WHEELER SD-36, SKODA MTD40C	Steam Turbine	Mazut	46,500	46,500	27,000	2004	2034	1.47	1.63
		FOSTER WHEELER SD-36, SKODA MTD40C	Steam Turbine	Mazut	46,500	46,500	27,000	2004	2034	1.47	1.63
		MITSUI MAN B&W 12K90MC-S Mk6	Internal Combustion Engine	Mazut	51,120	49,230	30,000	2007	2047	1.47	1.63
		MITSUI MAN B&W 12K90MC-S Mk6	Internal Combustion Engine	Mazut	51,120	49,230	30,000	2008	2048	1.47	1.63
	Linoperamata Power Station	K1400-2 (T5001)	Steam Turbine	Mazut	14,000	13,200	7,000	1971	2020	1.1	1.15
		K1400-2 (T5002)	Steam Turbine	Mazut	14,000	13,200	7,000	1971	2020	1.1	1.15

		RAFAKO 00-110 type - JUGOTURBINA O-KD-25	Steam Turbine	Mazut	24,500	23,300	16,000	1977	2020	1.1	1.15
		BREDA two-pass Puertollamno - C,N,R, 100C	Steam Turbine	Mazut	24,000	22,500	10,000	1981	2021	1.1	1.15
		BREDA two-pass Puertollamno - C,N,R, 100C	Steam Turbine	Mazut	24,000	22,500	10,000	1981	2021	1.1	1.15
		SULZER 9RTAF58	Internal Combustion Engine	Mazut	11,000	10,500	4,800	1989	2020	1.1	1.15
		SULZER 9RTAF58	Internal Combustion Engine	Mazut	11,000	10,500	4,800	1989	2020	1.1	1.15
		SULZER 9RTAF58	Internal Combustion Engine	Mazut	11,000	10,500	4,800	1990	2020	1.1	1.15
		SULZER 9RTAF58	Internal Combustion Engine	Mazut	11,000	10,500	4,800	1990	2020	1.1	1.15
		General Electric MS 5001 (LA)	Gas Turbine	Diesel	14,000	13,800	2,000	1987	2020	1.1	1.15
		General Electric MS 5001 (LA)	Gas Turbine	Diesel	14,000	13,800	2,000	1988	2020	1.1	1.15

		GE LM6000 -PC -NLW -G12, aeroderivative	Gas Turbine	Diesel	39,000	38,300	5,000	2002	2027	1.1	1.15
		ABB GT 35C1 - Siemens SGT 500	Gas Turbine	Diesel	14,500	14,300	2,000	2001	2026	1.1	1.15
		GE LM2500+HSPT, aeroderivative	Gas Turbine	Diesel	27,950	27,300	5,000	2003	2018	1.1	1.15
	Chania Power Station	ABB V63 + 2xABBGT8	Combined Cycle	Diesel	132,300	130,300	40,000	1995	2030	3.9	1.25
		THOMASSEN PG 5341	Gas Turbine	Diesel	20,000	19,750	1,000	1985	2020	3.9	1.25
		FIAT TG20	Gas Turbine	Diesel	30,000	29,200	2,000	1986	2020	3.9	1.25
		ANSALDO 64,3	Gas Turbine	Diesel	59,370	58,000	5,000	1998	2023	3.9	1.25
		ANSALDO 64,3	Gas Turbine	Diesel	59,370	58,000	5,000	1998	2023	3.9	1.25
		GE LM2500+HSPT	Gas Turbine	Diesel	27,950	27,200	2,000	2003	2018	3.9	1.25
Rhodes	**Rhodes Power Station**	ELECTRIM - JUGOTURBINA	Steam Turbine	Mazut	14,500	13,700	10,000	1976	2020	1.2	1.29
		ELECTRIM - JUGOTURBINA	Steam Turbine	Mazut	14,500	13,700	10,000	1976	2020	1.2	1.29
		CEGIELSKI B&W 9RTA58	Internal Combustion Engine	Mazut	10,500	10,100	4,900	1990	2020	1.2	1.29

		CEGIELSKI B&W 9RTA58	Internal Combustion Engine	Mazut	10,500	10,100	4,900	1991	2021	1.2	1.29
		PIELSTICK 18VPC4,2-B	Internal Combustion Engine	Mazut	18,000	17,300	14,000	1997	2027	1.2	1.29
		PIELSTICK 18VPC4,2-B	Internal Combustion Engine	Mazut	18,000	17,300	14,000	1997	2027	1.2	1.29
		PIELSTICK 18VPC4,2-B	Internal Combustion Engine	Mazut	18,000	17,300	14,000	1997	2027	1.2	1.29
		THOMASSEN PG5341	Gas Turbine	Diesel	17,500	17,250	4,000	1986	2020	1.2	1.29
		GE TM2500	Gas Turbine	Diesel	22,000	21,700	4,500	2011	2036	1.2	1.29
		SIEMENS SGT 600	Gas Turbine	Diesel	20,000	19,600	3,000	1996	2021	1.2	1.29
		GE LM2500+HSPT	Gas Turbine	Diesel	27,000	26,400	5,000	2005	2028	1.2	1.29
		20 x MITSUBISHI S16R	Diesel Genset	Diesel	25,500	25,180	8,000	2010	2017	1.2	1.29
St, Efstratios	**Ag, Efstratios**	MAN D2566ME	Internal Combustion Engine	Diesel	0,080	0,077	0,045	1988	2020	1.36	1.51

	Power Station	MAN D2566ME	Internal Combustion Engine	Diesel	0,080	0,077	0,045	1988	2020	1.36	1.51
		HYUNDAI KD8AX	Internal Combustion Engine	Diesel	0,200	0,193	0,110	2002	2038	1.36	1.51
		HYUNDAI KD8AX	Internal Combustion Engine	Diesel	0,200	0,193	0,110	2002	2038	1.36	1.51
		HYUNDAI KD8AX	Internal Combustion Engine	Diesel	0,200	0,193	0,110	2002	2032	1.36	1.51
Thera	**Thera Power Station**	MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,635	2014	2039	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,635	2014	2039	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,635	2014	2039	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,635	2014	2039	1.12	1.17
		GE10B1	Gas Turbine	Diesel	10,647	10,327	4,000	2014	2039	1.12	1.17
		TURBOMACH TITAN 130	Gas Turbine	Diesel	13,192	12,796	5,000	2014	2019	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2014	2044	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,635	2007	2044	1.12	1.17

		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,635	2007	2044	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,635	2007	2044	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,635	2007	2044	1.12	1.17
		WARTSILA W18V32	Internal Combustion Engine	Mazut	8,032	7,791	4,016	2006	2035	1.12	1.17
		WARTSILA W18V32	Internal Combustion Engine	Mazut	8,032	7,791	4,016	2006	2035	1.12	1.17
		WARTSILA 12V32D	Internal Combustion Engine	Mazut	4,100	3,977	2,235	1987	2020	1.12	1.17
		WARTSILA 12V32D	Internal Combustion Engine	Mazut	4,100	3,977	2,235	1987	2020	1.12	1.17
		WARTSILA 12V32D	Internal Combustion Engine	Mazut	4,100	3,977	2,235	1987	2020	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2014	2044	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2014	2044	1.12	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2014	2044	1.12	1.17

		WARTSILA W18V32D	Internal Combustion Engine	Mazut	6,514	6,318	3,257	1998	2028	1.12	1.17
Ikaria	**Ikaria Power Station**	FIAT B308ESS	Internal Combustion Engine	Mazut	0,750	0,693	0,487	1967	2020	2.2	1.8
		CEG,-SULZER 12ATV 25H	Internal Combustion Engine	Mazut	2,260	2,090	1,130	2005	2035	2.2	1.8
		FIAT B308ESS	Internal Combustion Engine	Mazut	0,750	0,693	0,487	1967	2020	2.2	1.8
		FIAT B308ESS	Internal Combustion Engine	Mazut	0,750	0,693	0,487	1967	2020	2.2	1.8
		CKD 6-27,5 B8S	Internal Combustion Engine	Diesel	1,100	1,017	0,640	1994	2024	2.2	1.8
		CKD 6-27,5 B8S	Internal Combustion Engine	Diesel	1,100	1,017	0,640	1994	2024	2.2	1.8
		CEG,-SULZER 16ATV25H	Diesel Genset	Mazut	3,104	2,871	1,552	2001	2023	2.2	1.8
		SACM AGO12DSHR	Diesel Genset	Diesel	0,800	0,740	0,600	1978	2020	2.2	1.8
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.2	1.8

		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.2	1.8
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.2	1.8
Karpathos	**Karpathos Power Station**	WARTSILA W12V32	Internal Combustion Engine	Mazut	5,327	5,060	2,663	2005	2035	1.41	1.43
		WARTSILA W12V32	Internal Combustion Engine	Mazut	5,327	5,060	2,664	2007	2037	1.41	1.43
		DAIHATSU 8DV-26	Internal Combustion Engine	Diesel	1,800	1,710	1,050	1984	2029	1.41	1.43
		DAIHATSU 8DV-26	Internal Combustion Engine	Diesel	1,800	1,710	1,050	1984	2029	1.41	1.43
		WARTSILA VASA 8R22MD	Diesel Genset	Diesel	0,850	0,807	0,600	1985	2020	1.41	1.43
		MITSUBISHI	Diesel Genset	Diesel	1,100	1,075	0,638	2007	2037	1.41	1.43
		MITSUBISHI	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2039	1.41	1.43
Kos-Kalymnos	**Kalymnos Power Station**	GMT C426ESS	Internal Combustion Engine	Mazut	1,800	1,728	1,152	1976	2026	1.1	1.11
		GMT C426ESS	Internal Combustion Engine	Mazut	1,800	1,728	1,152	1976	2026	1.1	1.11

		GMT C426ESS	Internal Combustion Engine	Mazut	1,800	1,728	1,152	1976	2026	1.1	1.11
		GMT C426ESS	Internal Combustion Engine	Mazut	1,800	1,728	1,152	1976	2026	1.1	1.11
		GMT C4212ESS	Internal Combustion Engine	Mazut	2,700	2,592	2,000	1976	2026	1.1	1.11
		WARTSILA W32-18V	Internal Combustion Engine	Mazut	8,250	8,027	4,125	2011	2040	1.1	1.11
	Kos Power Station	MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2005	2033	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2005	2033	1.33	1.41
		SULZER-FINCANTIERI 18ZAV40S	Internal Combustion Engine	Mazut	8,000	7,600	5,360	1995	2025	1.33	1.41
		HANJUNG-MAN 7K60MC-S	Internal Combustion Engine	Mazut	11,600	11,020	5,800	1994	2024	1.33	1.41
		HANJUNG-MAN 7K60MC-S	Internal Combustion Engine	Mazut	11,600	11,020	5,800	1994	2024	1.33	1.41
		HANJUNG-MAN 7K60MC-S	Internal Combustion Engine	Mazut	11,600	11,020	5,800	1994	2024	1.33	1.41

		H,S,D/MAN 9K60MC-S	Internal Combustion Engine	Mazut	16,500	15,675	8,250	2005	2035	1.33	1.41
		H,S,D/MAN 9K60MC-S	Internal Combustion Engine	Mazut	16,500	15,675	8,250	2005	2035	1.33	1.41
		STAL GT35C	Gas Turbine	Diesel	12,500	11,875	5,000	1994	2020	1.33	1.41
		MTU 16V 4000G60F	Internal Combustion Engine	Diesel	1,600	1,520	0,800	2002	2032	1.33	1.41
		MTU 16V 4000G60F	Internal Combustion Engine	Diesel	1,600	1,520	0,800	2002	2032	1.33	1.41
		MTU 16V 4000G60F	Internal Combustion Engine	Diesel	1,600	1,520	0,800	2002	2033	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2036	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2036	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2036	1.33	1.41

		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2005	2033	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2005	2033	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2005	2033	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2005	2033	1.33	1.41
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2005	2033	1.33	1.41
Lesvos	**Lesvos Power Station**	GMT A420,12	Internal Combustion Engine	Mazut	4,500	4,275	2,925	1984	2029	2.45	0.59
		GMT A420,12	Internal Combustion Engine	Mazut	4,500	4,275	2,925	1984	2029	2.45	0.59
		FINCAN-SULZER 18ZAV40S	Internal Combustion Engine	Mazut	7,500	7,125	5,360	1998	2028	2.45	0.59
		WARTSILA 18V38A	Internal Combustion Engine	Mazut	11,000	10,450	5,500	2009	2039	2.45	0.59
		WARTSILA 18V38A	Internal Combustion Engine	Mazut	11,000	10,450	5,500	2009	2039	2.45	0.59
		WARTSILA 12V46B	Internal Combustion Engine	Mazut	10,360	9,842	5,180	2000	2030	2.45	0.59

		CEGIELSKI 9RTAF58	Internal Combustion Engine	Mazut	9,500	9,025	5,500	1988	2020	2.45	0.59
		ABB STAL GT35C	Gas Turbine	Diesel	12,500	11,875	5,000	1994	2020	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2014	2044	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2014	2044	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2014	2044	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2014	2044	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2014	2044	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2014	2044	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2014	2044	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2014	2044	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2015	2045	2.45	0.59
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2015	2045	2.45	0.59
Lemnos	**Limnos Power Station**	SUMITOMO-NIIGATA 8L40X	Internal Combustion Engine	Mazut	2,200	2,090	1,350	1980	2029	1.11	1.26

		SUMITOMO-NIIGATA 8L40X	Internal Combustion Engine	Mazut	2,200	2,090	1,350	1980	2029	1.11	1.26
		SUMITOMO-NIIGATA 8L40X	Internal Combustion Engine	Mazut	2,200	2,090	1,350	1980	2029	1.11	1.26
		WARTSILA NSD18V32LN	Internal Combustion Engine	Mazut	6,514	6,188	3,257	1998	2028	1.11	1.26
		WARTSILA NSD18V32LN	Internal Combustion Engine	Mazut	6,514	6,188	3,257	1998	2028	1.11	1.26
		WARTSILA VASA 8R22MD	Diesel Genset	Diesel	0,850	0,825	0,600	1985	2020	1.11	1.26
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2039	1.11	1.26
Mykonos	**Mykonos Power Station**	MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.32	1.17
		CEGIELSKI 16ATV25H	Internal Combustion Engine	Diesel	2,000	1,940	1,450	1988	2020	2.32	1.17
		MITSUBISHI 18KU30A	Internal Combustion Engine	Diesel	5,880	5,703	2,940	2008	2035	2.32	1.17
		MITSUBISHI 18KU30A	Internal Combustion Engine	Diesel	5,880	5,703	2,940	2011	2040	2.32	1.17

		MITSUBISHI 18KU30A	Internal Combustion Engine	Diesel	5,880	5,703	2,940	2009	2039	2.32	1.17
		WARTSILA 12V32D	Internal Combustion Engine	Diesel	4,100	3,977	2,235	1987	2020	2.32	1.17
		FINCANTIERI BL230,20P	Internal Combustion Engine	Diesel	2,100	2,037	0,750	1992	2022	2.32	1.17
		FINCANTIERI BL230,20P	Internal Combustion Engine	Diesel	2,100	2,037	0,750	1993	2023	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2006	2036	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2006	2036	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2006	2036	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2039	2.32	1.17

		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2039	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2039	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2039	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2039	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2039	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2039	2.32	1.17
		TURBOMACH TITAN 130	Gas Turbine	Diesel	13,060	12,668	5,000	2015	2039	2.32	1.17
		Cummins QSK60	Diesel Genset	Diesel	1,355	1,330	0,677	2015	2045	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2015	2045	2.32	1.17
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2015	2045	2.32	1.17
Paros	**Paros Power Station**	MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2005	2033	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2005	2033	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.87	1.14

		FINCANTIERI-SULZER18ZA V40S	Internal Combustion Engine	Mazut	9,000	8,640	5,360	1995	2025	2.87	1.14
		GMT-FIAT A420,8	Internal Combustion Engine	Mazut	3,400	3,264	1,960	1984	2029	2.87	1.14
		GMT-FIAT A420,8	Internal Combustion Engine	Mazut	3,400	3,264	1,960	1984	2029	2.87	1.14
		WARTSILA NSD-12V46	Internal Combustion Engine	Mazut	10,360	9,945	5,180	1998	2028	2.87	1.14
		WARTSILA NSD-12V46	Internal Combustion Engine	Mazut	10,360	9,945	5,180	1998	2028	2.87	1.14
		H,S,D/MAN 7K60MC-S	Internal Combustion Engine	Mazut	11,200	10,752	5,600	2005	2035	2.87	1.14
		CEGIELSKI 6RTAF58	Internal Combustion Engine	Mazut	6,000	5,760	3,150	1988	2020	2.87	1.14
		CEGIELSKI 16ATV25H	Diesel Genset	Diesel	2,500	2,400	1,450	1991	2021	2.87	1.14
		CEGIELSKI 16ATV25H	Diesel Genset	Diesel	3,104	2,979	1,552	2001	2031	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.87	1.14

		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2007	2037	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2038	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2038	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2038	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2038	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2038	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2038	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2038	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2008	2038	2.87	1.14
		MTU 4000	Diesel Genset	Diesel	1,200	1,175	0,675	2011	2040	2.87	1.14
		TURBOMACH TITAN 130	Gas Turbine	Diesel	13,060	12,537	5,000	2015	2033	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,625	2007	2037	2.87	1.14
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,625	2007	2037	2.87	1.14

Samos	**Samos Power Station**	WARTSILA W32 - 18V	Internal Combustion Engine	Mazut	8,250	7,840	4,125	2009	2037	1.38	1.51
		WARTSILA W32 - 18V	Internal Combustion Engine	Mazut	8,250	7,837	4,125	2009	2037	1.38	1.51
		WARTSILA W32 - 18V	Internal Combustion Engine	Mazut	8,250	7,837	4,125	2011	2040	1.38	1.51
		CEGIELSKI 6RTAF-58	Internal Combustion Engine	Mazut	6,000	5,700	3,150	1989	2020	1.38	1.51
		CEGIELSKI 6RTAF-58	Internal Combustion Engine	Mazut	6,000	5,700	3,125	1989	2020	1.38	1.51
		CEGIELSKI 9RTA-F58	Internal Combustion Engine	Mazut	11,000	10,450	6,140	1999	2020	1.38	1.51
Skyros	**Skyros Power Station**	USSR Г-72	Internal Combustion Engine	Diesel	0,700	0,672	0,400	1976	2026	1.28	1.39
		USSR Г-72	Internal Combustion Engine	Diesel	0,700	0,672	0,400	1976	2026	1.28	1.39
		MITSUBISHI S16R-PTA	Internal Combustion Engine	Diesel	1,100	1,075	0,637	2006	2036	1.28	1.39

		MITSUBISHI S16R-PTA	Internal Combustion Engine	Diesel	1,100	1,075	0,637	2006	2036	1.28	1.39
		MITSUBISHI S16R-PTA	Internal Combustion Engine	Diesel	1,100	1,075	0,637	2005	2034	1.28	1.39
		MITSUBISHI S16R-PTA	Internal Combustion Engine	Diesel	1,100	1,075	0,637	2005	2034	1.28	1.39
		MITSUBISHI S16R-PTA	Diesel Genset	Diesel	1,100	1,075	0,637	2009	2039	1.28	1.39
Syros	**Syros Power Station**	WARTSILA W32 - 18V	Internal Combustion Engine	Diesel	8,250	7,837	4,125	2010	2040	1.25	1.43
		WARTSILA W32 - 18V	Internal Combustion Engine	Mazut	8,250	7,837	4,125	2009	2035	1.25	1.43
		CEGIELSKI 6RTAF58	Internal Combustion Engine	Mazut	6,000	5,700	3,150	1991	2021	1.25	1.43
		GMT-FIAT C4212ESS	Internal Combustion Engine	Mazut	3,000	2,850	2,000	1976	2026	1.25	1.43
		GMT-FIAT C4212ESS	Internal Combustion Engine	Mazut	3,000	2,850	2,000	1976	2026	1.25	1.43

		GMT-FIAT A420,12	Internal Combustion Engine	Mazut	4,500	4,275	2,925	1983	2030	1.25	1.43
		CEGIELSKI 12ATV25H	Diesel Genset	Diesel	2,200	2,090	1,300	2002	2032	1.25	1.43
Chios	**Chios Power Station**	CEGIELSKI 9RTAF58	Internal Combustion Engine	Mazut	9,500	9,025	5,500	1988	2020	1.32	1.39
		CEGIELSKI 9RTAF58	Internal Combustion Engine	Mazut	11,280	10,716	6,140	1996	2026	1.32	1.39
		H,S,D/MAN 9K60	Internal Combustion Engine	Mazut	14,476	13,752	7,238	2008	2038	1.32	1.39
		H,S,D/MAN 9K60	Internal Combustion Engine	Mazut	14,476	13,752	7,238	2009	2037	1.32	1.39
		GMT A420,12	Internal Combustion Engine	Mazut	4,500	4,275	2,925	1983	2030	1.32	1.39
		GMT - FIAT C4212ESS	Internal Combustion Engine	Mazut	3,500	3,325	2,000	1976	2026	1.32	1.39
		GMT - FIAT C4212ESS	Internal Combustion Engine	Mazut	3,500	3,325	2,000	1976	2026	1.32	1.39

		GMT A420,12	Internal Combustion Engine	Mazut	4,500	4,275	2,925	1983	2030	1.32	1.39
		GMT A420,12	Internal Combustion Engine	Mazut	4,200	3,990	2,925	1983	2030	1.32	1.39

ANNEX II.b

Table II.b Thermal power generators list in the Greek NGS (2016)

Power Generators Units										
Region	**Power Station**	**Unit Type**	**Fuel**	**Capacity Gross (MW)**	**Capacity Net (MW)**	**Technical Minimum (MW)**	**Commission Year**	**Decommission Year**	**Maint. Rate (%)**	**FOR (%)**
Macedonia	Agios Dimitrios I	Steam Turbines	Lignite	300	274	136,5	1984	2022	49.32	18.377
	Agios Dimitrios II	Steam Turbines		300	274	136,5	1984	2022	3.84	16.795
	Agios Dimitrios III	Steam Turbines		310	283	137	1985	2022	21.23	16.424
	Agios Dimitrios IV	Steam Turbines		310	283	137	1986	2022	46.58	18.879
	Agios Dimitrios V	Steam Turbines		375	342	171	1997	2023	37.26	11.264
	Amyntaio I	Steam Turbines		300	273	136,5	1987	2020	23.01	14.099
	Amyntaio II	Steam Turbines		300	273	136,5	1987	2020	1.37	8.852
	Kardia I	Steam Turbines		300	275	137,5	1975	2020	18.49	18.583
	Kardia II	Steam Turbines		300	275	137,5	1975	2020	3.84	18.389

	Kardia III	Steam Turbines		306	280	150	1980	2021	3.84	15.564
	Kardia IV	Steam Turbines		306	280	150	1981	2021	1.92	13.958
	Liptol 1	Steam Turbines		35	30	17	1959	2020	28.34	14.234
	Liptol 2	Steam Turbines		10	8	4	1965	2020	28.34	15.678
	Megalopoli- III	Steam Turbines		300	270	135	1975	2022	2.88	10.61
	Megalopoli- IV	Steam Turbines		300	260	130	1991	2023	4.25	14.962
	Meliti	Steam Turbines		330	292	186	2007	2025	5.62	11.322
	Ptolemaida II	Steam Turbines		122	116	58	1991	2028	7.5	18.973
	Ptolemaida III	Steam Turbines		287	270	135	1965	2028	7.5	17.763
	Ptolemaida V	CCGT		660	620	300	2022	>2040	7.5	6.42
Central Greece	AHS Lavrio (CCGT)	Gas Turbine	Natural Gas	120	119	41,2	1996	2034	2.19	9.698
		Gas Turbine		120	119	41,2				
		Gas Turbine		120	119	41,2				
		Steam Turbine		200	193,2	67,6				

		Gas Turbine		250	242	145,2				
		Steam Turbine		140	135,6	81,4				
	ALIVERI (CCGT)	Gas Turbine		250	243	145,8	2006	2023	1.37	7.716
		Steam Turbine		140	137	82,2				
	Alouminio (CHP)	Gas Turbine		130	123	67,1	2008	> 2040	12.19	2.278
		Gas Turbine		130	123	67,1		> 2040		
		Steam Turbine		90	84	45,8		> 2040		
	Elpedison Enthes (CCGT)	Gas Turbine		250	243	145,3	2004	> 2040	11.92	3.894
		Gas Turbine		142	140,2	84,1		> 2040		
		Steam Turbine		421	410	180		> 2040		
	HRON (CCGT)	Gas Turbine		290	282	125	2001	> 2040	17.12	0.728
		Steam Turbine		145	143	80		> 2040		
Peloponnese	Korinthos Power (CCGT)	Gas Turbine		822	811	360	2004	> 2040	6.03	1.696
		Steam Turbine		147	146	88		> 2040		

	Megalopoli (CCGT)	Gas Turbine		270	270	110	2019	> 2040	2.88	5.67
		Gas Turbine		270	270	110		> 2040		
		Steam Turbine		271	271	132		> 2040		
Central Greece	Protergia (CCGT)	Gas Turbine		285	282	145	2011	> 2040	4.38	1.976
		Steam Turbine		145	143,5	66		> 2040		
	This HRON	Gas Turbine		50	49,3	20	2008	> 2040	17.12	0.728
		Gas Turbine		50	49,3	20		> 2040		
		Gas Turbine		50	49,3	20		> 2040		
Macedonia	TPS KOMOTINIS	Gas Turbine		175	162,3	56,8	2010	2035	4.11	5.034
		Gas Turbine		175	162,3	56,8				
		Steam Turbine		170	151,7	53,1				

ANNEX III

Table III.a Emissions comparison from EVs under a V2G – restricted scenario vs. ICEs – 2030, Autonomous Batteries (AB.y.1.0)

Region	Average Consumption	EVs S1	EVs S2	V2G restricted Intensity - S1	V2G restricted Intensity - S2	Emissions Conventional vehicles - S1	Emissions Conventional vehicles - S2	Emissions EVs - S1	Emissions EVs - S2	Emissions Saved - S1	Emissions Saved - S2
	MWh/year car	Number		kg/MWh		tCO2eq					
Chios	2.24	1094	4550	454.52	505.04	1.129.45	4.698.64	1.112.01	5.140.21	17.45	-441.57
Creta	2.91	12609	52409	451.53	458.86	16.925.26	70.351.68	16.554.24	69.925.49	371.02	426.19
Ikaria	2.24	180	749	545.30	560.14	185.88	773.04	219.56	937.95	-33.68	-164.91
Karpathos-Kasos	2.24	121	504	462.90	546.97	125.17	520.39	125.51	616.56	-0.34	-96.17
Kos-Kalymnos	2.24	1070	4449	428.03	420.64	1.104.55	4.593.51	1.024.12	4.185.44	80.43	408.06
Lemnos	2.46	333	1384	625.40	641.73	377.96	1.572.24	512.02	2.185.52	-134.06	-613.28
Lesvos	2.24	1613	6709	502.43	560.17	1.665.15	6.927.31	1.812.25	8.405.54	-147.10	-1.478.23
Milos	2.46	100	417	453.47	553.11	113.73	473.16	111.71	566.90	2.02	-93.74

Mykonos	1.57	160	661	396.61	341.56	115.61	477.46	99.32	353.25	16.29	124.21
Paros	2.24	336	1393	512.43	376.42	346.43	1.438.26	384.53	1.172.72	-38.10	265.54
Patmos	2.24	267	1107	377.50	545.30	275.85	1.143.09	225.57	1.350.20	50.29	-207.11
Rhodes	2.24	92	384	534.76	501.41	95.29	396.43	110.38	430.57	-15.09	-34.14
Samos	1.57	2447	10176	386.98	138.02	1.768.49	7.355.44	1.482.44	2.199.02	286.05	5.156.42
Skyros	2.24	691	2875	450.63	451.16	713.65	2.968.44	696.61	2.900.97	17.04	67.47
Symi	2.24	82	339	54.81	32.87	84.36	350.36	10.02	24.95	74.35	325.41
Syros	2.24	415	1724	379.82	458.64	428.01	1.780.11	352.15	1.768.49	75.87	11.62
Thera	2.01	309	1280	506.95	543.25	287.10	1.189.50	315.27	1.399.76	-28.17	-210.25

Table III.b Emissions comparison from EVs under a V2G – restricted scenario vs. ICEs – 2040, Autonomous Batteries (AB.y.1.0)

Region	Average Consumption	EVs S1	EVs S2	V2G restricted Intensity -S1	V2G restricted Intensity -S2	Emissions Conventional vehicles - S1	Emissions Conventional vehicles - S2	Emissions EVs - S1	Emissions EVs - S2	Emissions Saved - S1	Emissions Saved - S2
	MWh/year*car	Number		kg/MWh		tCO2eq					
Chios	2.24	6212	22709	536.7	463.70	6.414.74	23.448.45	7.457.02	23.552.43	-1.042.28	-103.98
Creta	2.91	70783	266599	520.9	524.93	95.015.63	357.868.53	107.199.60	406.917.01	-12.183.97	-49.048.48
Ikaria	2.24	1022	3912	572.6	476.48	1.055.26	4.039.53	1.308.84	4.169.29	-253.58	-129.75
Karpathos-Kasos	2.24	688	2674	511.8	406.56	710.28	2.760.63	787.42	2.431.15	-77.15	329.48
Kos-Kalymnos	2.24	6073	23283	377.7	402.01	6.270.39	24.041.14	5.129.43	20.935.11	1.140.96	3.106.03
Lemnos	2.46	1890	7151	630.1	556.44	2.146.43	8.122.22	2.929.55	9.789.90	-783.12	-1.667.68
Lesvos	2.24	9159	25697	568.8	545.95	9.457.44	26.533.80	11.653.22	31.379.02	-2.195.78	-4.845.22
Milos	2.46	569	2139	297.4	525.77	645.99	2.429.35	416.18	2.766.74	229.81	-337.39
Mykonos	1.57	823	4580	358.6	361.51	595.21	3.310.39	462.36	2.592.33	132.85	718.06
Paros	2.24	1855	7865	469.69	493.60	1.915.07	8.120.76	1.948.42	8.682.79	-33.35	-562.03

Patmos	2.24	1440	6761	364.95	286.97	1.487.26	6.981.58	1.175.72	4.339.87	311.54	2.641.71
Rhodes	2.24	524	1971	522.77	350.83	541.23	2.035.39	612.89	1.546.77	-71.65	488.62
Samos	1.57	13892	52985	476.54	422.93	10.041.01	38.297.83	10.364.84	35.085.38	-323.83	3.212.45
Serifos	2.24	3925	9987	454.22	453.72	4.052.39	10.312.16	3.987.12	10.134.98	65.28	177.18
Skyros	2.24	463	1888	326.51	238.50	478.01	1.949.93	338.08	1.007.38	139.93	942.55
Symi	2.24	2344	8991	579.33	405.10	2.420.84	9.283.60	3.037.93	8.146.36	-617.10	1.137.25
Syros	2.01	1662	7871	368.30	370.02	1.544.37	7.314.77	1.232.09	5.862.81	312.28	1.451.96
Thera	2.24	6212	22709	193.4	229.46	6.414.74	23.448.45	2.686.93	11.654.98	3.727.81	11.793.47

Table III.c Emissions comparison from EVs under a V2G – restricted scenario vs ICEs – 2030, Interconnected (I.x.1.0.a)

Region	Average Consumption	EVs S1	EVs S2	V2G restricted Intensity -S1	V2G restricted Intensity -S2	Emissions Conventional vehicles - S1	Emissions Conventional vehicles - S2	Emissions EVs - S1	Emissions EVs - S2	Emissions Saved - S1	Emissions Saved - S2
Unit	**MWh/year*car**	**Number**		**kg/MWh**		**tCO2eq**					
Chios	2.24	1094	4550	202.48	201.93	1.129.45	4.698.64	495.39	2.055.19	634.07	2.643.45
Creta	2.91	12609	52409	327.50	373.85	16.925.26	70.351.68	12.007.00	56.970.86	4.918.26	13.380.81
Ikaria	2.24	180	749	444.39	374.41	185.88	773.04	178.93	626.95	6.95	146.09
Karpathos-Kasos	2.24	121	504	439.95	262.77	125.17	520.39	119.29	296.21	5.88	224.18
Kos-Kalymnos	2.24	1070	4449	409.99	460.71	1.104.55	4.593.51	980.94	4.584.14	123.61	9.37
Lemnos	2.46	333	1384	440.95	413.06	377.96	1.572.24	361.00	1.406.77	16.95	165.48
Lesvos	2.24	1613	6709	457.33	201.93	1.665.15	6.927.31	1.649.58	3.030.01	15.58	3.897.29
Milos	2.46	100	417	445.47	352.54	113.73	473.16	109.74	361.33	3.99	111.83
Mykonos	1.57	160	661	202.48	207.17	115.61	477.46	50.71	214.26	64.90	263.20
Paros	2.24	336	1393	249.17	482.42	346.43	1.438.26	186.98	1.502.97	159.45	-64.70
Patmos	2.24	267	1107	358.34	290.35	275.85	1.143.09	214.12	718.92	61.73	424.17

Rhodes	2.24	92	384	484.27	312.94	95.29	396.43	99.95	268.73	-4.67	127.70
Samos	1.57	2447	10176	400.46	373.37	1.768.49	7.355.44	1.534.08	5.948.84	234.40	1.406.60
Serifos	2.24	691	2875	202.48	201.93	713.65	2.968.44	313.01	1.298.40	400.64	1.670.04
Skyros	2.24	82	339	409.83	270.86	84.36	350.36	74.89	205.57	9.47	144.80
Symi	2.24	415	1724	229.89	276.15	428.01	1.780.11	213.14	1.064.84	214.87	715.27
Syros	2.01	309	1280	438.10	408.12	287.10	1.189.50	272.46	1.051.58	14.65	137.92
Thera	2.24	1094	4550	202.48	201.93	1.129.45	4.698.64	495.39	2.055.19	634.07	2.643.45

Table III.d Emissions comparison from EVs under a V2G – restricted scenario vs ICEs – 2040, Interconnected (I.x.1.0.a)

Region	**Average Consumption**	**EVs S1**	**EVs S2**	**V2G restricted Intensity -S1**	**V2G restricted Intensity -S2**	**Emissions Conventional vehicles - S1**	**Emissions Conventional vehicles - S2**	**Emissions EVs - S1**	**Emissions EVs - S2**	**Emissions Saved - S1**	**Emissions Saved - S2**
Unit	**MWh/year*car**	**Number**		**kg/MWh**		**tCO2eq**					
Chios	2.24	6212	22709	193.4	229.46	6.414.74	23.448.45	2.686.93	11.654.98	3.727.81	11.793.47
Creta	2.91	70783	266599	481.5	324.83	95.015.63	357.868.53	99.104.82	251.801.84	-4.089.20	106.066.68
Ikaria	2.24	1022	3912	366.1	425.47	1.055.26	4.039.53	836.88	3.722.89	218.38	316.65
Karpathos-Kasos	2.24	688	2674	253.0	298.61	710.28	2.760.63	389.23	1.785.63	321.05	975.00
Kos-Kalymnos	2.24	6073	23283	417.9	423.54	6.270.39	24.041.14	5.676.66	22.056.11	593.73	1.985.03
Lemnos	2.46	1890	7151	443.7	469.39	2.146.43	8.122.22	2.062.89	8.258.38	83.54	-136.15
Lesvos	2.24	9159	25697	310.8	229.46	9.457.44	26.533.80	6.366.08	13.188.54	3.091.36	13.345.26
Milos	2.46	569	2139	337.0	400.62	645.99	2.429.35	471.51	2.108.17	174.49	321.18
Mykonos	1.57	823	4580	235.4	235.42	595.21	3.310.39	303.56	1.688.13	291.65	1.622.26
Paros	2.24	1855	7865	288.64	448.21	1.915.07	8.120.76	1.197.38	7.884.21	717.69	236.55
Patmos	2.24	1440	6761	317.76	329.94	1.487.26	6.981.58	1.023.70	4.989.66	463.56	1.991.92

Rhodes	2.24	524	1971	286.62	355.61	541.23	2.035.39	336.03	1.567.87	205.21	467.52
Samos	1.57	13892	52985	340.11	424.28	10.041.01	38.297.83	7.397.48	35.197.78	2.643.52	3.100.05
Skyros	2.24	3925	9987	185.61	229.46	4.052.39	10.312.16	1.629.29	5.125.62	2.423.10	5.186.53
Symi	2.24	463	1888	262.17	307.80	478.01	1.949.93	271.46	1.300.09	206.55	649.84
Syros	2.24	2344	8991	270.95	313.81	2.420.84	9.283.60	1.420.80	6.310.59	1.000.04	2.973.01
Thera	2.01	1662	7871	333.91	463.78	1.544.37	7.314.77	1.117.04	7.348.43	427.33	-33.66